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A Maharatna Company

Ministry of POWER
GOVERNMENT OF INDIA

Partnership to Advance Clean Energy – Deployment (PACE-D)

PACE-D Technical Assistance Program

Best Practices Manual for
Indian Supercritical Plants

February 2014

This report is made possible by the support of the American People through the United States Agency for International Development (USAID). The contents of this report are the sole responsibility of Nexant, Inc. and do not necessarily reflect the views of USAID or the United States Government. This report was prepared under Contract Number AID-386-C-12-00001.

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The report was prepared under the direction of Dr. Gerry Choi, Nexant's Vice President, along with a Nexant team comprising Peter du Pont, Kavita Kaur, Jem Porcaro and Jessica Pelham.

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FOREWORD

The U.S.-India bilateral partnership on clean coal technology plays an important role in the U.S.-India energy cooperation.

Cooperation on clean coal technologies, which started in 1982 with the Alternative Energy Research and Development program, has expanded over time with several programs including the Energy Management Consultation and Training Program (EMCAT); the Program for Accelerating Commercial Energy Research (ACER); the Program for Accelerating Commercial Energy Research (PACER); the Indo-U.S. Coal Preparation Program; and the Greenhouse Gas Pollution Prevention (GEP) project.

Building on the legacy of these previous programs, USAID, with the support from Department of State, is now working on a range of cleaner fossil activities under the Partnership to Advance Clean Energy – Deployment (PACE-D). The five year, USD 20 million PACE-D Technical Assistance Program aims to support India in deploying clean energy technologies, thereby reducing its greenhouse gas emissions.

As part of this program, USAID is collaborating with the Indian Ministry of Power (MOP), Central Electricity Authority (CEA) and NTPC, to improve the operational efficiency of supercritical thermal power plants. The focus is on knowledge exchange via different media including technical workshops, international conferences and publications.

This manual is a compilation of the lessons learned from operating supercritical (SC) plants in U.S. utilities over the last fifty years. It aims to share experiences and knowledge with the Indian thermal power professionals to enable them to adapt this information to operate their plants efficiently, reliably and safely.

The manual comprises specific sections focused on the operation, performance monitoring and maintenance of various plant components. The aspects related to safety, reliability, availability and efficiency of supercritical units are also addressed, including experience and case studies from some of the best performing units in United States.

I thank the MOP, CEA and NTPC for their support and guidance in preparing the manual, and hope it is helpful in assisting you in many functional areas.

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(भारत सरकार का उद्यम)
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केन्द्रीय कार्यालय/Corporate Centre

FOREWORD

Thermal power sector in India has entered into an era of supercritical technology.

Supercritical technology is not only more efficient but also more environment friendly with lower carbon emission intensity. NTPC, the largest power utility in India, is proud to initiate this transformation in Indian power sector with installation of first supercritical thermal power plant at Sipat. NTPC has aggressive plans to add capacities to meet national needs and future capacities will be based on supercritical technology. Other utilities, public and private, are also installing power plants based on supercritical technology.

NTPC has been adjudged one of the most efficient utilities in terms of capacity utilization in the world and has created benchmarks in Operation and Maintenance (O&M) of sub-critical thermal power plants and combined cycle plants. With large capacities of supercritical units, the capability of power sector to deliver will depend on how efficiently the capacities are operated and maintained. The experience of world community in operating and maintaining the supercritical capacities will be of great help to Indian power plants engineers in learning the problems faced particularly in boiler O&M, water chemistry requirements, O&M of turbines and safety. The quality start-up of units is critical for good health and reliable operation of supercritical machines.

U.S. utilities have been operating supercritical power plants for over 50 years. I am glad that under USAID's PACE-D Technical Assistance Program, the experience of the U.S. utilities is compiled in the form of best practices document and is being made available to Indian power sector.

I thank all the U.S. experts who have contributed to this compilation. I also thank NTPC-Sipat, CenPEEP and Operation Services team for associating in this effort to make it more useful to address perceived concerns in O&M of these units. This is an excellent effort and I am sure, this "Best Practices Manual" will be of great help to NTPC and all other Indian utility engineers.

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Director – Operations
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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The demand for electricity is rapidly increasing in India as economic growth continues. Coal remains the fuel of choice for electricity generation and much of the new demand is expected to come from coal-fired power plants. Fifty nine percent (~135 GW) of the existing ~230 GW power generated in the country comes from coal-fueled power plants. An additional 71 GW of electricity is planned in the next five years and much of this, nearly 69 GW, will come from coal-based plants. Most of the existing coal-fired plants are subcritical units operating around 34 percent or less in efficiency.

The next generation of coal plants is expected to have supercritical (SC) and ultra-supercritical (USC) units that have an efficiency of 38-45 percent depending on design, operating parameters, and ambient conditions. In July 2008, India released its first National Action Plan on Climate Change (NAPCC) outlining existing and future policies and programs addressing climate change mitigation and adaptation. The plan pledges that India's per capita greenhouse gas (GHG) emissions "will at no point exceed that of developed countries even as we pursue our development objectives."

The Plan's broad goals are consistent with sustainable development (environmental protection, stewardship, economic growth, and societal benefits) and energy security. One of the elements of the NAPCC is to raise the efficiency level of power generation. SC and USC plants will meet those expectations and help raise the national average efficiency of Indian coal-fired plants to 40 percent over two decades. This will significantly reduce coal consumption and help reduce the carbon footprint in the country.

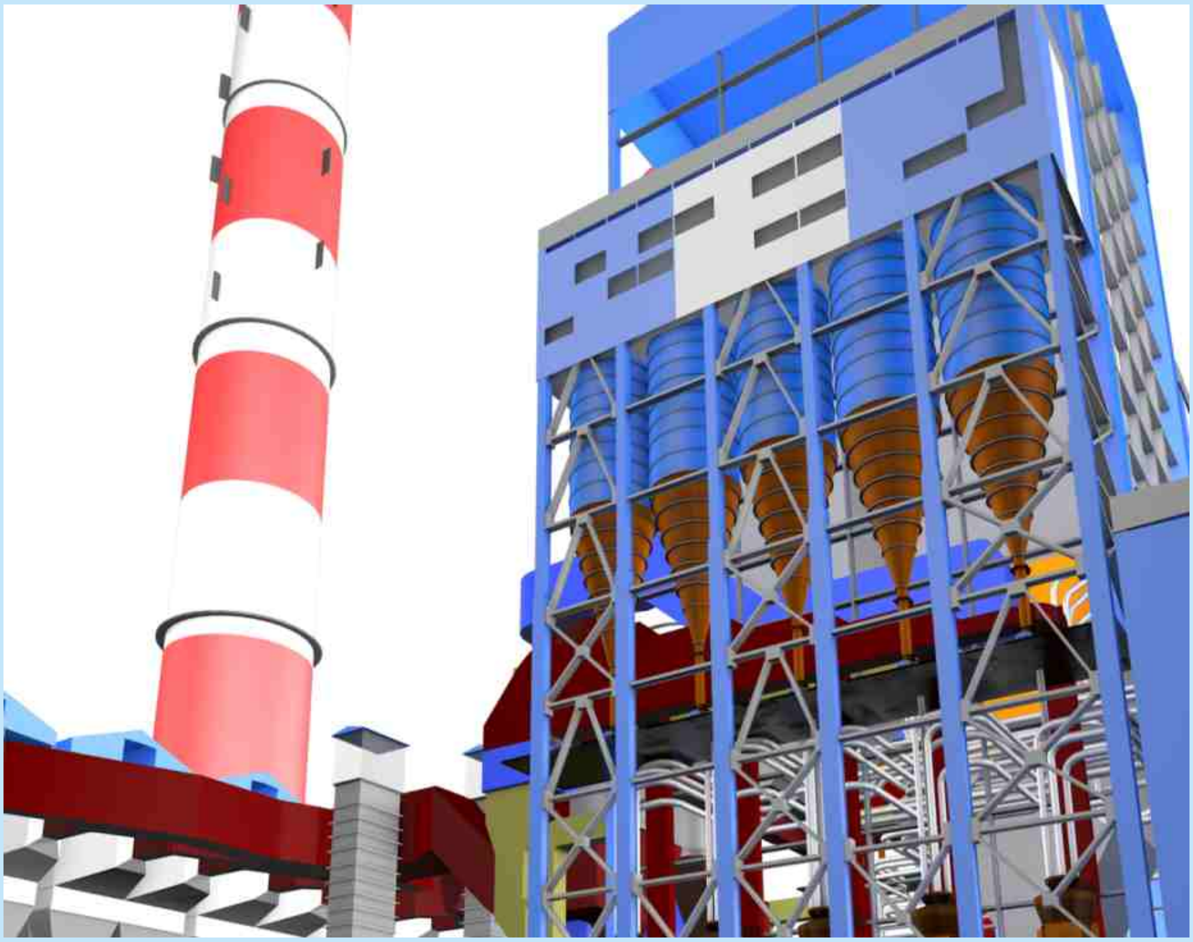
This Best Practices Manual is a compilation of the lessons learned and the experience gained from operating such plants over the last fifty years in U.S. utilities. The early deployment in the U.S. with SC and USC plants will help in learning and gaining expertise to be able to operate these plants safely, efficiently and reliably to make a major contribution to the growth of the Indian power sector.

The primary objective of the Best Practices Manual is to help Indian power producers to:

- Reduce GHG emissions
- Sustain economic growth
- Improve safety and productivity in the workplace

Information is provided under various chapters that address four key areas of interest:

1. Introduction and overview of the current status of SC and USC units worldwide
2. Reduction of GHG emissions in India by improved efficiency
    a. Water consumption reduction
    b. Boiler performance improvement
    c. Turbine cycle performance improvement
3. Sustain economic growth in India through improved fleet reliability
    a. Startup and shutdown
    b. Water chemistry
    c. Addressing boiler reliability
4. Adapt "Best Practices" to improve workforce safety and productivity
    a) Work process management for improved availability
    b) Plant safety considerations



The remainder of this Executive Summary provides a brief summary of each of the main chapters of the report, starting with Startup and Shutdown and ending with Plant Safety Considerations.

Startup and Shutdown

While supercritical units have been operating for many decades, supercritical Benson boilers have traditionally not been the preferred choice of U.S. utilities. The situation, however, has changed recently. For example, Duke Energy and American Electric Power (AEP) have selected a Benson design for their supercritical units at Cliffside and Turk plants, respectively. Other U.S. utilities have done the same, owing to the advantages of Benson design's distinct cyclic operation.

It appears that the new generation of supercritical units in India will mostly adopt the Benson design. The Benson design offers many superior features when compared to the earlier generation of supercritical units. Speed of startup, fewer thermal transients, the simplicity of the startup system, the ability to easily cycle load, and improved reliability all favor the use of a Benson design.

In India, the units will not be cycled nearly as much as in the U.S. India has a generation deficit of such proportions that all of the supercritical units will be considered "base loaded" for the near future. However there will come a time in the life of these units that they will see some cycling to lower loads and even some reserve shutdowns at certain times of the year. The Benson design will allow for this type of future cycling style of operation.

In the U.S., even the most efficient of the earlier class of supercritical units are required to cycle and experience routine shutdowns periodically. Even the newer class of supercritical units will need to cycle to lower loads on a routine basis. A number of recent combined cycle plants have followed this trend. Because of this, the supercritical plant operators are very experienced at hot and warm starts as well as shutdowns.

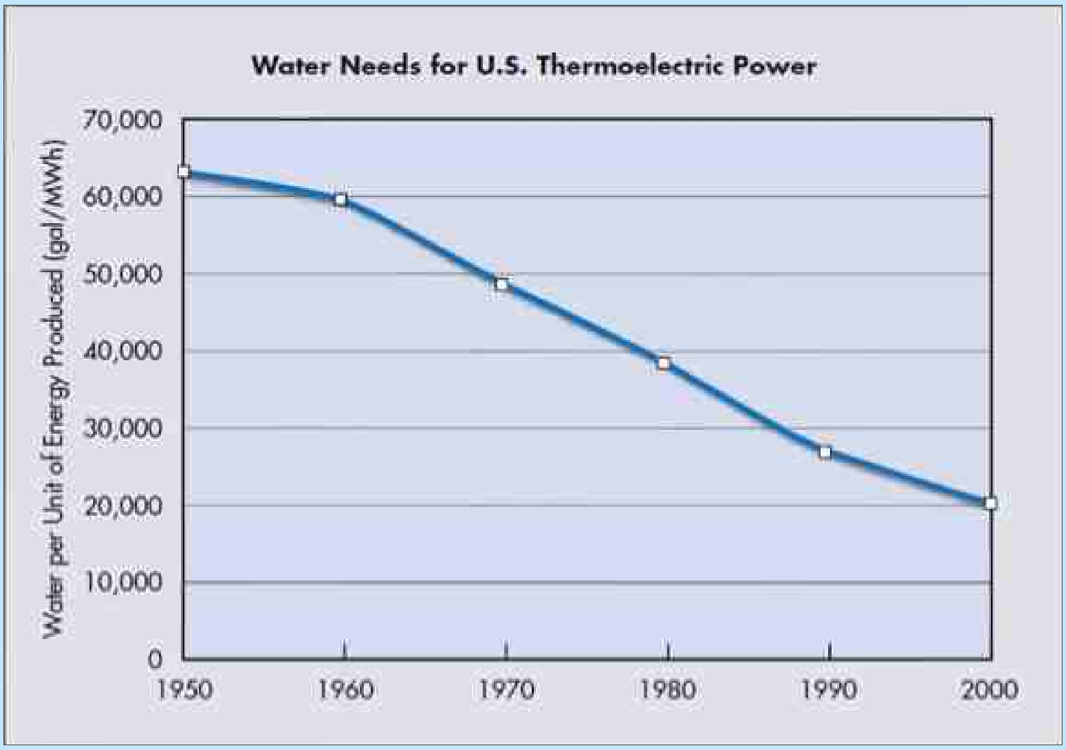
Water Consumption

Water availability for power production is becoming constrained in many parts of the world. The challenges faced in India are no different from those from the rest of the world. Today, a wide variety of processes and technologies are being deployed to recover, recycle, and re-use water. The three major areas where water is consumed in a power plant include: steam production; condenser cooling; and bottom ash transport. Wet or dry flue gas desulfurization (FGD) systems for sulfur dioxide removal from the flue gas also consume a significant amount of water. Plant designs can vary depending on site water availability. However, by adopting "best practices," water consumption could be significantly reduced at most sites.

The first step in water reuse and conservation is to route the cooling water blow down to a disposal pond, from which treated water is recycled back into the plant. Slurry from ash and gas handling systems can be handled in a similar fashion. Other steps that can be adopted to promote water re-use include using waste water treatment, reverse osmosis, evaporation, and zero liquid discharge systems.

The efficiency of water usage in U.S. power plants has greatly improved over the past fifty years. Although the volume of water withdrawn for power plant usage has increased by a factor of five (5) since 1950, the amount of power generated actually has grown at a factor of fifteen (15). As a result, the water withdrawn per megawatt hour has decreased by more than two thirds (Figure 4-1) [6]. This reflects a significant improvement in water reuse and conservation, and improvement in overall plant efficiency in the U.S.

Figure 4-1: Water Needs for U.S. Thermoelectric Power Plants



The challenges faced in India are no different than those faced around the world, as shown in Table 4-1.

Table 4-1: Water Issues and Challenges for Power Generators POWER Magazine - July 1, 2013 [4]

Country	Electricity generated by coal	Drivers for reducing freshwater consumption	Approaches for reducing freshwater consumption
South Africa	85%	Abundant coal resources. Coal resources and power plants are in dry regions.	Use efficient supercritical technologies, dry cooling, advanced control systems, dry bottom ash handling, and desalination. Participate in water infrastructure development, incentives, and water metering.
China	80%	Large coal resources, so coal is to be the dominant fuel for decades. China is world's third-driest country, and there are specific policies for reducing freshwater consumption.	Replace, retrofit small, inefficient plants. Increase use of supercritical and ultrasupercritical units. Use dry cooling. Explore integrated gasification combined cycle (IGCC) technology. Use desalination at power plants.
Australia	70%	Coal is likely to supply more than half the total electrical generating capacity through 2035. Many areas are subject to long drought. Groundwater use is restricted.	Supercritical steam cycles. Dry cooling. Turbine upgrades. Coal drying. In-plant water recycling.
India	70%	More power is needed than is available. Coal is expected to remain the dominant fuel through at least 2050.	Increase efficiency. Use advanced supercritical steam parameters. Replace/retrofit old, inefficient plants. Reuse and recycle wastewater. Research IGCC.
Denmark	50%	No domestic coal resources.	Supercritical and ultrasupercritical plants. Cogeneration.
Germany	49%	Coal is to remain a significant power generation fuel for several years. About half of coal-fired generation is from low-rank lignite, and power plants are aging.	Replacement of old, inefficient plants with new, efficient plants, including ultrasupercritical. Research into plants with high steam parameters and new materials. Lignite drying.
Japan	25%	Imports all fuel. It is often difficult to obtain water from local governments.	Use supercritical and ultrasupercritical technologies and low-water-consuming emissions control equipment.
Italy	13%	Coal-fired power generation is to increase due to coal's lower costs; coal is expected to provide about one-third of generation as of 2013.	Replace/retrofit old plants with ultrasupercritical technology.

Global investment. Efficiency improvements along with supercritical and ultrasupercritical technologies are gaining favor in countries that face water constraints. *Source: NETL*

Water Chemistry

Water chemistry impacts all equipment coming in contact with water or steam. A power generating facility cannot operate reliably without a quality water chemistry program. Water chemistry expectations and limits should be established utilizing the best available technology. Best practices outlined in the water chemistry balance section include action levels for the operator at specified limits to ensure quality water chemistry to protect the equipment. Oxygenated treatment is recommended as the best water chemistry program to provide reliable long-term operation of supercritical units.

Reliable operation of supercritical units requires specifying and installing accurate, precision chemical instrumentation and developing and implementing a quality maintenance program to retain its integrity. The ultimate objective is to ensure that the instrumentation provides the reliability necessary to make correct decisions for proper operation of the equipment.

Improper water chemistry is at the root of many woes in the operation of a steam power plant. Several topics such as Steam generator (SG) tube failure, corrosion, corrosion fatigue, stress corrosion cracking, condenser tube leak and leak testing method, etc. are discussed in this chapter as they relate to water chemistry.

To ensure high standard of water quality requires setting up a structure that assigns responsibility for maintenance of the equipment such that it can be accomplished in a reliable manner for providing a routine maintenance program. The optimal structure of each organization is different, so chapter 5 provides the criteria that should be considered when assigning instrumentation maintenance responsibilities. A proper routine maintenance program is recommended.

SG tube failure is the leading cause of unavailability in power generating facilities. It is therefore imperative to be attentive to the root causes of tube failures. Four causes of tube failure are addressed in this report. These causes are ID pitting, stress corrosion cracking, corrosion fatigue, and waterwall cracking. Utilizing the criteria described in the chemical cleaning best practices in Section 5.7 ensures a clean steam generator minimizing the potential for OD waterwall circumferential cracking. Strict adherence to the water chemistry limits and action levels defined in Section 5.1 maximizes optimal boiler tube reliability. Utilizing a reheat drying procedure, as a best practice, every time the unit is shutdown can significantly reduce the potential for pitting in the reheater tubes caused by moisture remaining when the unit is shutdown.

Many of the corrosion problems found in boilers/steam generators and turbine blades can be traced back to condenser leaks. Leaking condenser tubes allow cooling water to enter the condensate and feedwater supply. Cooling water is not purified to the extent of boiler/steam generator feedwater and contains many contaminants. Any contaminants introduced to the condensate and feedwater supply can become active components of numerous corrosion mechanisms. Condenser leaks are typically the greatest source of contaminants to condensate and feedwater.

Mechanical and corrosion mechanisms that can result in condenser tube failure are addressed. Best practices addressed to help ensure condenser reliability include Eddy Current Testing (ECT) of condensers to help determine the remaining life of the tubes, trend tube degradation, and/or to locate tubes which may fail before the next major planned outage so they can be plugged. Plugging procedures are also addressed to ensure reliable repairs of leaking tubes. Considerations to address when making end-of-life decisions are presented.

There are several contaminants that can result in turbine blade deposits or corrosion. These include iron, sodium, silica, chloride, and sulfate. The contaminants cause performance degradation or turbine blade failure. Best practices recommend monitoring iron with Millipore samples to establish that the coloration of the sample must be "snow white" to meet the required standards. The parameters that are required to control iron are also discussed. The phase transition zone (PTZ) is presented as an especially susceptible area for deposition. The expected appearance is presented to enable quality inspection and sampling. Another part of maintaining a reliable well performing turbine is a well-structured, documented turbine sampling process. Guidelines for this are also presented.

Operating supercritical plants with high reliability and high efficiency requires structuring the chemical functions of the organization to utilize best practices in the laboratory and chemical analysis. This requires developing a structure that optimally allocates all of the necessary functions. These include effective monitoring, sampling, analysis, direction and goals, R&D, and oversight. A structure that divides these tasks between General Chemistry Standards and control department (Service Corp), Central Lab, and Plant lab is presented in such a way that optimally utilizes the skills resident in each entity.

Timely and effective chemical cleaning, i.e., maintaining water chemistry in a supercritical unit before encounting heat transfer problem can be the life saver of a steam generator. However, accurately detecting the scale on the tube ID before it significantly impacts heat transfer and tube life can be very challenging. Section 5 provides guidance on utilizing best available technology to measure oxide deposits and setting up criteria to enable reliable steam generator operation. Historic methods of determining tube deposits includes removing a tube sample from the steam generator at a location most likely to have the heaviest deposit during major outages and scraping the tube sample, or bead blasting it. This was an effective method as long as the only deposits to be removed were the iron transported from the condensate and feedwater systems. As less corrosive water treatments such as oxygenated treatment, became known it became practical to extend the time between cleanings, duplex insitu oxide layers formed making the old detection methods ineffective. Supercritical units operated on oxygenated treatment (OT) form very tenacious deposits which contain three distinct layers. These layers are defined as spinel, hematite and magnetite. With these, the Scanning Electron Microscope (SEM) is the best method for accurate tube sample analysis and condition assessment. After SEM analysis, thermal conductivity can be determined by the porosity of the deposits of both the structural material (the tube) and of the medium which fills the pores can be determined.

Boiler Performance Analysis

There are many factors that can influence supercritical boiler and combustion performance. Unit design and fuel quality have a major influence on a plant's performance. Plant operations, performance, load response, reliability, and capacity are all inter-related. So, any approach for optimization or management of performance should be comprehensive in nature, taking into account mechanical adjustments of the firing systems, fuel quality, boiler cleanliness, airflow measurement, furnace oxygen control, and many other factors.

In an effort to identify stealth or “hidden” performance issues, a program must be organized with the plant departments committed and working together to achieve and preserve plant performance.

With a shortage of domestic coal and newly enacted environmental regulations, Indian power plants must perform well, or suffer the consequences of increased fuel costs, poor reliability, and reduced generating capability. During plant operations, thermal energy is lost through a plant's stack, rejected to the cooling tower, and/or used by the plant auxiliary equipment. Thus, an effective plant performance program encompasses various program activities that are used to evaluate, sustain, improve, and preserve a boiler's performance.

Other essential items include tools and equipment required to collect representative samples for analysis. This defines the measurement process and best practices or tools required to identify and reduce gaps in performance. A performance preservation program is a best practices process that requires dynamic tools and processes, grounded on fundamentals.

Turbine Cycle Performance Analysis

Optimizing turbine cycle performance in a supercritical unit requires implementing best practices of both the turbine and all its associated equipment. The turbine cycle performance is affected not only by the turbine condition, but by the performance of the condenser, cooling tower, feedwater heaters, valves, etc. All of these are impacted by water chemistry, and operations and maintenance practices. Accomplishing world class performance requires learning and implementation of best practices. Many best practices are detailed in the body of chapter 7 that can help achieve the desired world class performance.

To improve the turbine heat rate requires first understanding the design basis of the turbine cycle and providing a way to know and track the deviations from design performance. Simply tracking the heat rate can be very deceiving, since it is impacted by seasonal conditions and peripheral equipment. Chapter 7 provides means of trending deviations from design heat rate in a way that enables observing unit degradation, and tracking improvements.

Although tracking deviations from design heat rate enables better monitoring of unit performance, understanding the drivers of this performance requires quality monitoring of unit parameters. Modern instrumentation enables continuous monitoring and tracking of temperatures and pressures and enables utilizing those parameters to continuously calculate more complex information, such as turbine efficiency, heater Terminal Temperature Difference (TTD), condenser performance, etc. Tracking this information allows continuous improvement to the cycle heat rate.

Condenser performance can be optimized through several strategies. Some of these include monitoring strategies, equipment utilized, maintaining cleanliness through water chemistry, mechanical cleaning, and regularly evaluating the condenser performance. The best instrumentation available should be used to detect condenser tube leakage thereby protecting the cycle water chemistry. Instrumentation to detect the leaking tube in a timely effective manner is presented in chapter 7.

Optimal design, operation, and monitoring of heaters are presented to provide the means to operate the heaters in a reliable, efficient manner that also maximizes generation and minimizes its cost. Means to monitor the heaters and implement practices that minimize cycling of heaters, and maximize performance are also included. The best practice described within chapter 7 details a technology to improve heater reliability and extend heater life as end-of life is approached.

The cooling tower provides the interface of the cooling water with the environment. Degradation in its performance prevents the condenser and turbine from attaining optimal performance. Ensuring effective performance of a cooling tower requires monitoring the thermal performance of the equipment. However, the key to attaining consistent cooling tower performance requires developing and maintaining a quality water chemistry program. The biological activity is the initiating mechanism for fouling of high efficiency fills. The parameters for monitoring water quality and the equipment that can provide this monitoring is described in this chapter. Indexes that monitor the biological activity and water quality and the criteria for control are also provided along with methods that can be employed to monitor and inspect tower film fill for fouling. Tests to measure tower performance and the penalties that are incurred are included.

Operating turbines in a cost-effective manner while maximizing reliability requires a quality turbine maintenance program. Inefficient turbines can significantly impact the unit heat rate, which impacts the fuel cost. Implementing a quality condition-based maintenance program that regularly evaluates unit operation can extend the duration between outages and cost-effectively recover those losses. Protocols to accomplish these tasks are presented. Guidelines for both online and outage-based assessments are provided. Inspection and sampling are included as an integral part of an effective auditing program. Turbine repair practices including processes for both modular repair and individual part repair are described.

Work Process Management for Improved Availability

People affect the business “bottom line” most, not science and technology. Applied technology is important, but not to the same degree as getting people to focus on achieving “bottom line” business goals and expectations. This requires management discipline and training, structure, accountability, and “checks and balances” that properly managed work processes provide.

When an organization is striving for “Best Practice” status by improving the way it does business, there are two types of challenges it must address: technical and managerial. Technical challenges like equipment performance are addressed with technical solutions such as engineering design or modification. Most capital projects are technical solutions.

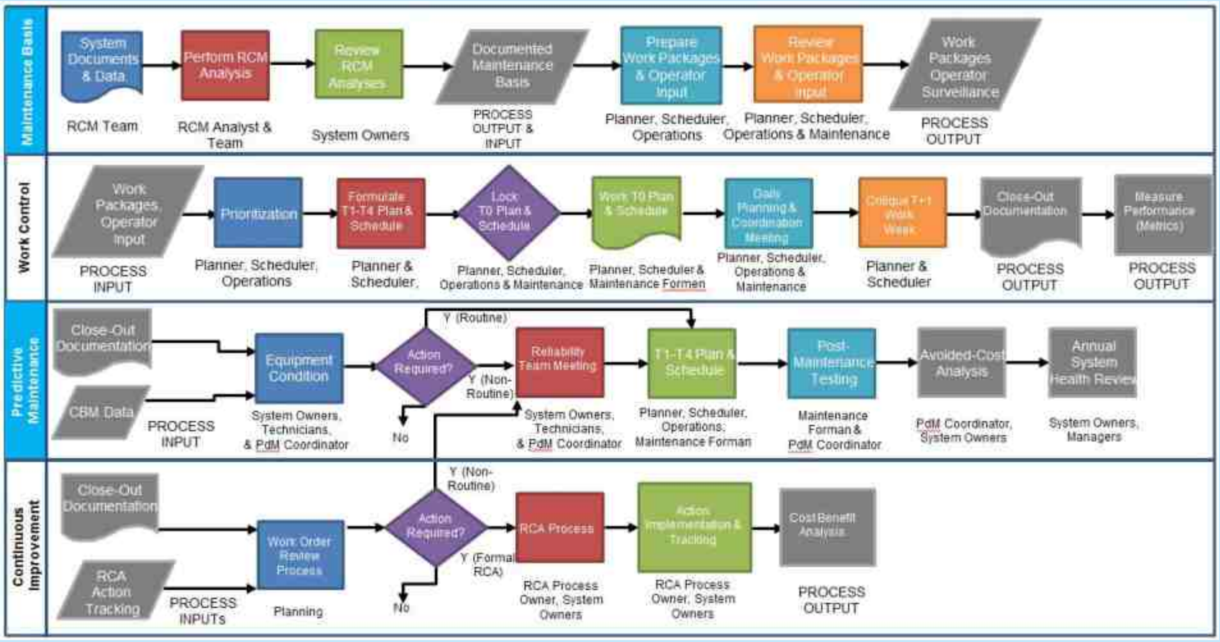
Unfortunately, striving for a best practice is not a technical challenge. It cannot be solved with technical solutions like a new computer system or a predictive maintenance program. Achieving “Best Practice” is a human challenge and must be addressed with a management solution. When the problem is recognized as managerial, then the right tool for the job is a comprehensive, integrated work management process whose design is robust and whose application is consistent (Example in Figure 8-1). Therefore, in an effort to reach best practice levels and sustainable value in planning and scheduling efforts, the entire organization/plant and the associated work culture must be ready to make the necessary changes.

Because the people's involvement is critical to integrating and sustaining the work processes, individuals should be provided with the training and support that makes them most qualified to perform their jobs efficiently. Training and support run the full spectrum; from adequately training technical personnel doing the work, to plant and corporate management support and commitment. If management support and sponsorship is not in place, then the evolution of an organization from “as found” to some desired state is an exercise in futility and should not be continued.

A major part of the organizational evolution is focused on the culture of the organization. The culture needs to be adjusted to the point that plant personnel are prepared and receptive to the changing management philosophies. A work culture that is open and eager for change is the foundation for all other process and technological improvements.

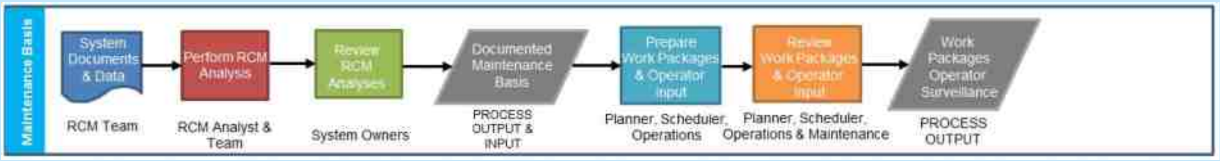
Work culture is as manageable as any other aspect of the business. In essence, addressing an organization work culture is part of management's responsibility. The work culture is managed by setting the example and by setting expectations and making sure people live up to them, including making and keeping commitments. The commitments are made in a well-defined work management process and are lived up to through a process of accountability. Accountability is the means to keeps process and work culture aligned.

Figure 8-1: Example of an Integrated Plant Work Process



A summary description of each sub-process is provided in Figure 8-2 to familiarize and provide the context for more detailed discussions.

Figure 8-2: Developing the Maintenance Basis and Coupling the Work Management Process

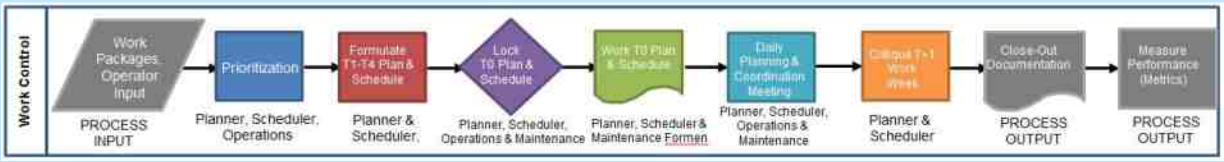


The maintenance basis is established using the Reliability-Centered Maintenance (RCM) methodology. This conceptual methodology identifies the most effective and applicable maintenance tasks for each piece of equipment. This task selection defines the Maintenance Basis (optimum mix of CM, PM, PdM, PAM). A full classical RCM study involves an exhaustive investigation of all failure modes and their effects. This approach, however, has now been streamlined for the utility industry. This streamlined RCM includes the investigation of common, known failure modes and the analysis of the resultant effects, as well as the determination of effective and applicable maintenance tasks to address those modes.

This process shown in Figure 8-3 includes:

- Rank the plant systems and equipment
- Determine the failure modes and causes
- Select tasks (CM -run to failure, PM, PdM and PAM) that addresses the failure modes
- Capture the operations and maintenance procedures
- Capture standardized work packages

Figure 8-3: Work Control or Work Management Process



The Work Control or Work Management Process shown above in Figure 8-3 covers, planning, prioritization, scheduling, work execution and work close-out. Planning and Scheduling covers:

- Back log management
- Work Packages
- Parts availability (Stores/Inventory)
- Parts staging
- Daily schedule
- Multi-week Schedule
- Outage schedule
- Tracking planning accuracy
- Tracking Schedule Compliance

The Work Execution element of Work Process covers the following:

- Man-hour Utilization
- Staff Training
- Tools Availability
- Tool Upgrade to Latest Technology
- Track Rework vs. Total Work
- Track "Wrench" Time vs. Total time

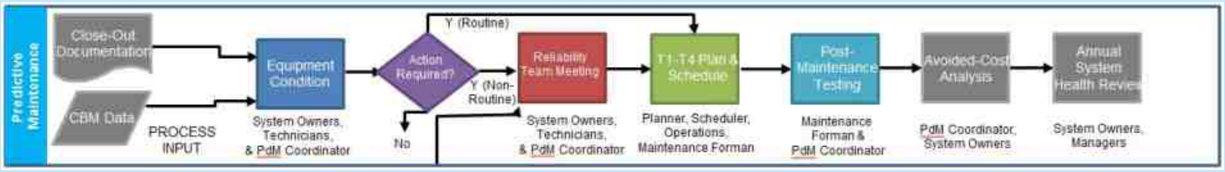
Work Close-out element captures:

- Obtaining detailed maintenance histories
- Addressing post maintenance testing

- Reviewing work orders with the intent of eliminating work in the future
- Feedback to the origination of the work orders

PdM is performing maintenance based on the condition of the equipment. The basic periodic condition monitoring technologies are non-destructive examination, visual inspection, vibration, thermography, and oil analysis, acoustic and ultrasonic surveillance, motor testing (winding resistance, capacitance/dissipation factors, insulation resistance, etc.). This is shown in Figure 8-4.

Figure 8-4: Predictive Maintenance Process

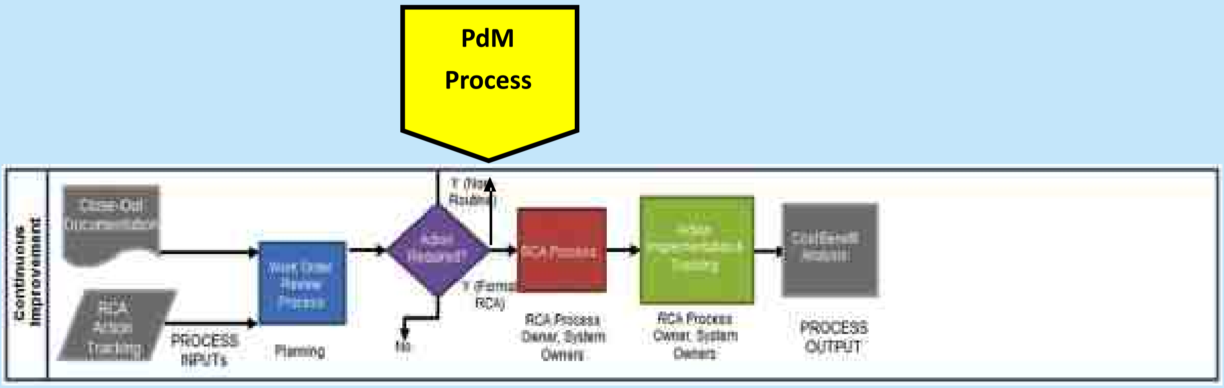


PdM is however more extensive than just applying technologies for monitoring. To be completely effective, PdM condition monitoring data is collected and combined with other pertinent data related to a particular component. Integrated, with continuous data streams from data historians, and augmented by equipment maintenance history from Computerized Maintenance Management Systems (CMMS) most of the more common failure modes and mechanisms that affect power plant equipment can be detected and/or validated long before damage becomes significant.

Integration of all relevant data for hundreds of components and getting support for the program from all plant departments is complicated. Therefore, most advanced PdM programs are led by a PdM Coordinator. The PM process includes:

- Determining roles and responsibilities
- Establishing the PDM Work Process and how it fits into the plant work process as seen in Figure 8-5.
- Determining the equipment that will be in the program and the condition indicators that will be used to determine the equipment condition.
- Establish channels of communication
- Preparing a condition assessment report
- Establishing and measuring the Return on Investment and Cost Benefits
- Establishing and tracking continuous improvement metrics

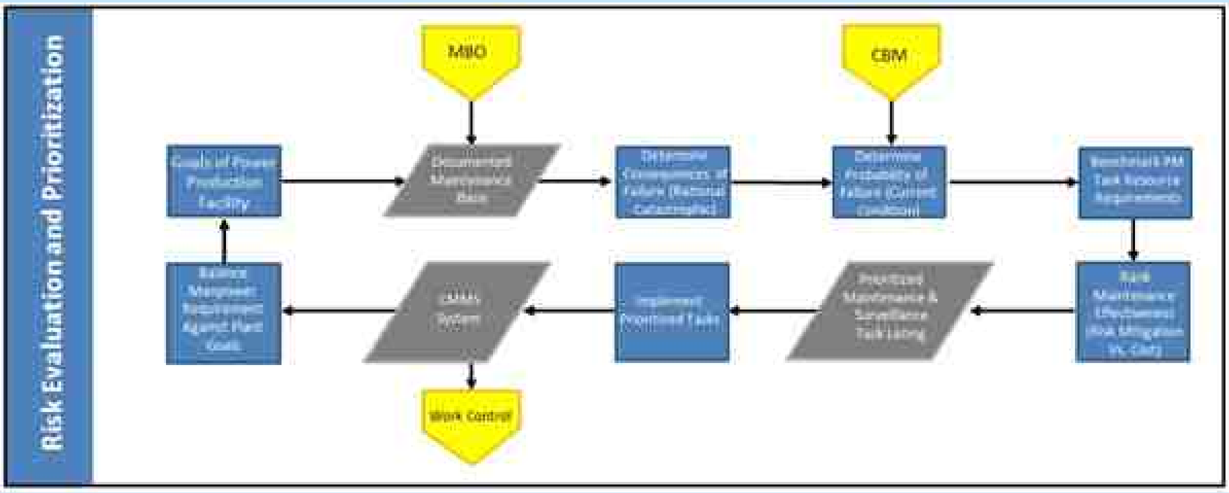
Figure 8-5: Continuous Improvement Process



It is important to establish a continuous improvement process, which has a feedback loop. This process determines what type of work was performed, could it have been avoided and what steps should be taken to eliminate it. This process covers:

- Root Cause Analysis
- Determine the Failure mode and cause
- Modify the maintenance basis
- Review periodically the "good work orders" and modify the basis as needed.
- Track work order types

Figure 8-6: Risk Evaluation and Prioritization Process



The Risk Evaluation and Prioritization (REAP) process shown in Figure 8-6 was developed to have a means to make better business decisions on whether or not to perform outage activities using information on the condition of equipment and on the outage task's financial impact. The same model can be applied to similar decisions for performing routine PM tasks and capital projects to achieve maximum gain from limited funding. REAP results in the assignment of value to the individual tasks. This value derived from performing the task is then plotted against the cost of performing the task. From this, an optimized decision is possible for what tasks to perform that result in the highest worth for the plant.

REAP consists of three activities:

1) High level filtering of all possible outage task activities to assure all regulatory work is included, only outage work is selected and work addresses all of the failure modes that have been experienced. Assumptions are made that all tasks are preventive or condition-based.
2) Placing value on the selected tasks versus the cost to performance of the task.
3) Preparing and presenting the data so that decisions can be made and agreed upon.

Addressing Boiler Reliability

Boiler and Heat Recovery Steam Generator (HRSG) tube failures remain a major issue for the power production industry. In this chapter it is made apparent that, in fact, boiler tube failure is an "effect" not a cause. Therefore, discussions in the Tube Prevention Strategies (Section 9.1) are centered on eliminating the causes of tube and header damage and controlling propagation of the damage to meet or exceed component life expectations. A "Best Practice" approach is introduced for putting an end to tube and header failures with Targeted Boiler Management.

It is important to understand the causal factors i.e. damage mechanisms to try to understand why tube and header failure remains a problem. To do this, Section 9.2 (Coal Quality Considerations), Section 9.3 (Water Chemistry Considerations), and Section 9.4 (Metallurgical Considerations) explore the mechanisms under each as well as strategies and techniques in use to defend components against these. Detailed description of each is given to understand what is going on deep inside each component. Section 9.5 discusses operational conditions that impact tube failures and 9.6 details quality assurance and quality control considerations. Then, in Section 9.7, Boiler Condition Monitoring and Diagnostics, an overview is given on some "Best Practice" technologies (APR and Diagnostic Rules) available in the market, the conditions they help control, and how they may be used for control under different operating conditions. In addition, the technologies, tactics and "Best Practice" methods that exist to defend against them are explained. Targeted Boiler Management was developed based on what has and has not worked historically. It applies these learnings from the past and combines them with evolving technology to provide a way to balance the computer automated and manually applied "Best Practice" tools for maximum reliability.

Plant Safety Considerations

Safety is an area that always needs attention and continuous improvement. The consequences of injuries in the workplace is just too great to not give it equal importance as cost, quality, production and all other areas of focus in a power plant. This chapter provides information on best practices being used in power plants that have invested in attempting to reach world-class performance in the area of safety. More specifically, chapter 9 addresses the following:

- The importance of establishing a vision and mission for safety is emphasized.
- A suggested set of safety guiding principles that cover safety comprehensively.
- Emphasizes the absolute necessity for holding management fully accountable for effective processes, programs and results.
- The necessity of having executive management, including the CEO, actively involved in the safety effort.
- The need for effective safety programs and the concern for them becoming stale and perfunctory.
- The safety pyramid concept and the importance of including near misses, unsafe acts and unsafe conditions.
- A comprehensive process framework for managing safety.
- The use of a CEO forum for all serious injuries.
- The concept of having a site wide Safety Steering Team led by the site head. The target audience for the safety message. What works for the CEO may not motivate first line employees.

It is hoped that by implementing these best practices Indian utilities can see fundamental change and continuous improvement in the area of safety.

The manual will provide valuable guidance on implementing proven best practices so that new SC and USC fleets will operate at optimum performance levels and meet or exceed their design expectations.

Introduction 1.0

1.0 INTRODUCTION

India is the fourth largest energy consumer in the world after the United States, China, and Russia. The United States Department of Energy (U.S. DOE) and Energy Information Administration (EIA) project that India and China will account for the biggest share of Asian energy demand growth through 2035. Availability and access to energy is important for economic and societal development.

The available electricity in India has been reported to be 917 kWh per person as compared to the well over 3,000 – 4,000 kWh for the rest of the modern world. With over 300 million Indians without any electricity, coal is the answer, at least in the next ten years, for reducing the widespread energy shortages. The consumption of coal in India is expected to increase by 170 percent over the next two decades, as the Indian power sector is poised to grow from ~230 GW to nearly 400 GW within a short span of 10 years [1].

India is a country with tremendous growth and therefore an increasing demand for electricity. Most of the new power demand will be supplied with supercritical coal-fired units. The U.S. and India have had a longstanding effort to share technology and ways to improve power generation. It is also in the mutual interest of the U.S., India, and the rest of the world to minimize emissions from all existing and future generation. Two of the best ways to do this are to assure all plants are reliable and operated at the highest efficiency by deploying supercritical units.

This best practices manual is provided for guidance in several key areas related to supercritical boiler technology and includes topics of relevant interest, which include topics such as start-up, safety and shut-down challenges, water consumption, water chemistry, boiler and turbine performance, work process management, reliability and plant safety management.

Figure 1-1: Artist's Rendering of a Supercritical Coal Fired Power Plant

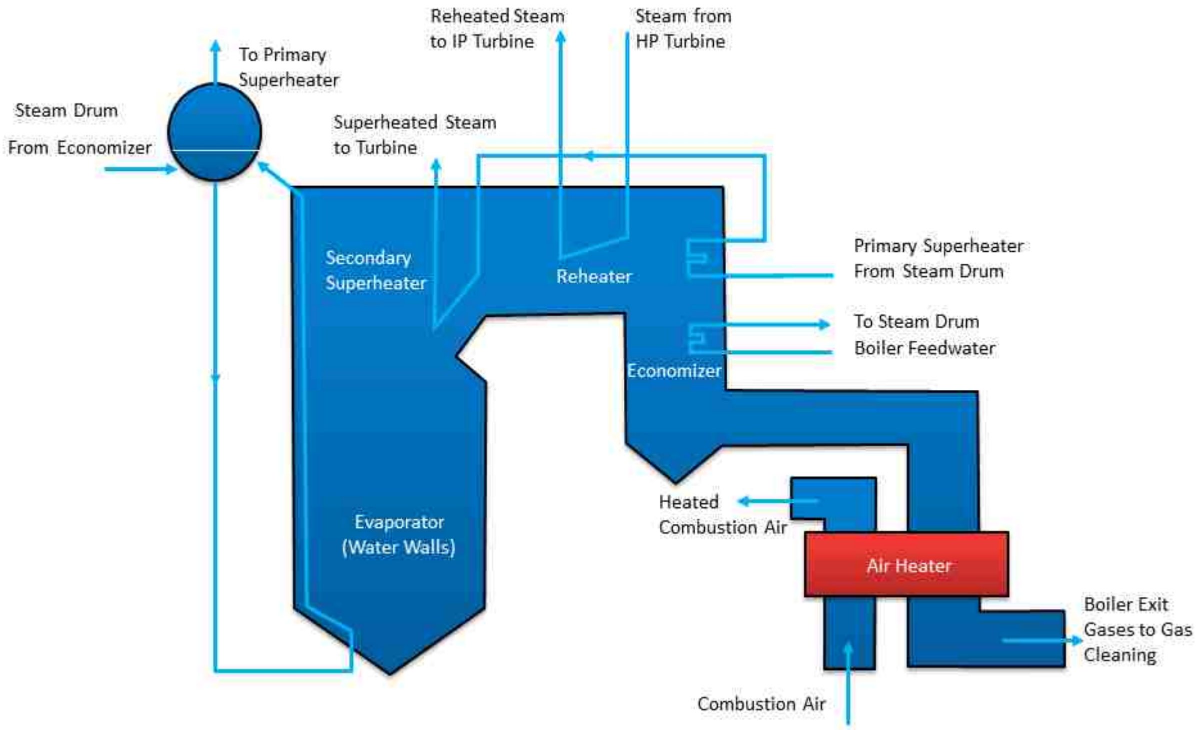
Background 2.0

2.0 BACKGROUND

2.1 HISTORICAL OVERVIEW

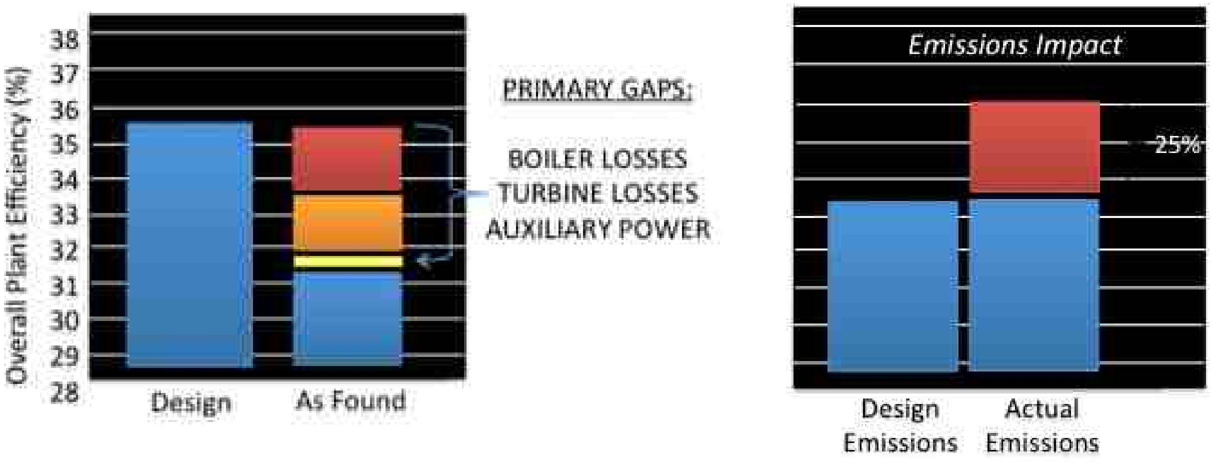
Many existing coal-fired plants operate at lower than design efficiency because of challenges with operation and maintenance, and kinds of fuel. The efficiency for many existing plants in India is less than 30 percent to a high of about 34 percent. These plants typically have drum type or subcritical boilers (Figure 2-1).

Figure 2-1: Subcritical "Drum" Boiler (typical)



Although proven to be very reliable, many of these existing SC thermal power plants are inefficient and offer significant potential for emissions reduction through improved technology. Compared to the average emissions from coal-fired units in developed countries such as the U.S. and Europe, India's thermal power plants emit significantly more CO_2 per kWh produced because of low efficiency (Figures 2-2 and 2-3).

Figure 2-2 and Figure 2-3: Case Study Design vs. Actual Impact on Emissions



Between 2008 and 2010, studies were completed on state utility board plants and, in one case, the energy efficiency deficiencies related to controllable heat rate factors resulted in nearly a 25 percent increase in avoidable greenhouse gas emissions [7].

Studies of Indian coal-fired plants have been documented in IEA reports [3]. One of the reasons for the shortfall in thermal efficiency is related to poor and in many cases declining coal quality and supply. India suffers from a major shortage of electrical generation capacity, even though it is the world's fourth largest energy consumer after United States, China, and Russia. The IEA estimated that India will need to add between 600 GW to 1,200 GW of additional new power generation capacity before 2050. Both coal and water are precious commodities in India, and power generated from fossil fuels, especially coal, is dependent on water. According to the U.S. Geological Services, on average, approximately 0.106-0.125 m^3 (28-33 gallons) of water are required for each kWh of power produced from coal. In the last 50-60 years, a 50 percent reduction in the water requirements for power production has taken place and there are yet more opportunities to reduce water usage and consumption in power production [16].

Similarly, technological advancements have also significantly reduced the consumption of coal. To help improve and sustain efficiency for power generation in India, the country is now installing advanced SC power plants as a standard. As previously illustrated in Figure1-1, a 3-4 percent absolute or 10-15 percent relative thermal performance improvement can yield substantial environmental improvements. Thus, the transition from subcritical to supercritical technology is part of a strategic plan to meet India's 12th five-year plan to 2017 (and beyond).

Pulverized coal combustion is the most widely used technology in coal-fired power plants and is based on decades of experience. The first supercritical plants came into operation in the U.S. in the early 1960s. Today, there are around 500 SC and USC pulverized coal units around the world. However, many learning curve and reliability challenges prevailed. Advancements in SC boiler technology have provided a significant contribution for improving power plant efficiency, reliability, and air pollution control.

The term "supercritical" refers to conditions above the critical point where distinct liquid and gas phases do not exist as it becomes a single working fluid (22.1MPa and 374.1℃). With supercritical technology, the cycle operates with a single-phase fluid, and there is no need for separating steam and water in a drum (Figure 2-4).

Another name for supercritical units normally used is "once-through" since there is no need for a steam drum (Figure 2-5).

Figure 2-4: Illustration of Properties for Subcritical and Supercritical Steam

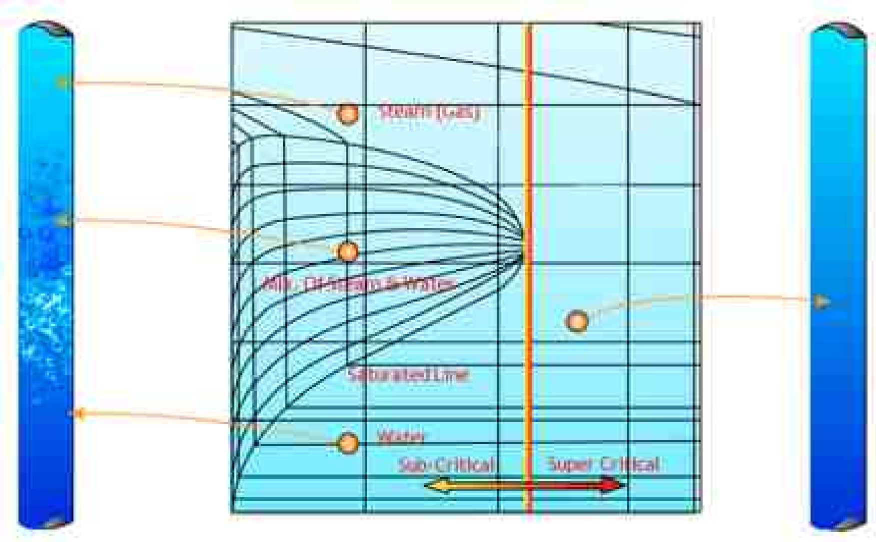
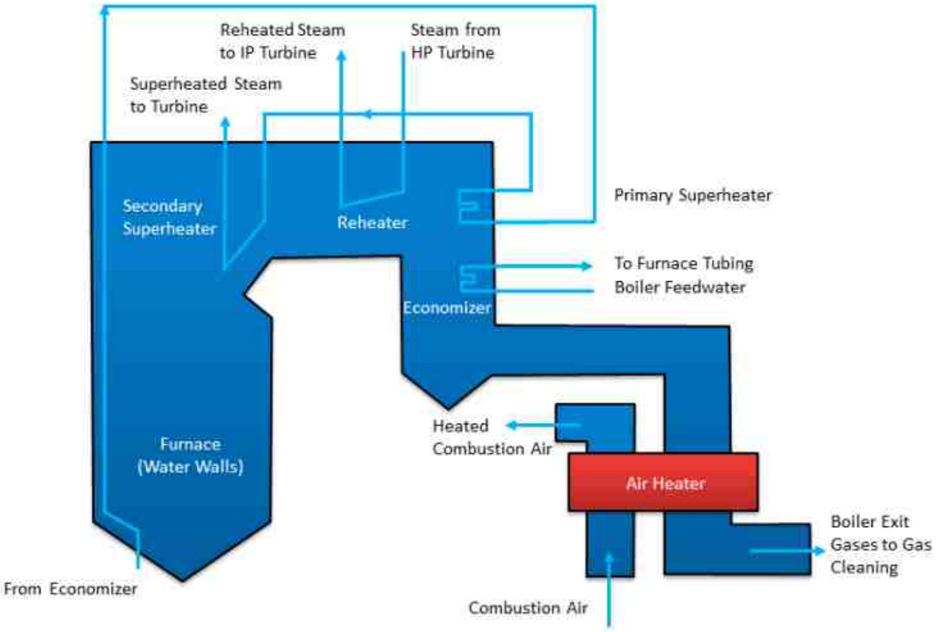


Figure 2-5: Supercritical Boiler (typical)



The pressure and temperature ranges for subcritical and supercritical and ultra-supercritical steam generation systems used in this report are shown in Table 2-1.

Definition of supercritical and ultra-supercritical boiler pressure and temperature profiles differs from one country to another. Thus the usage of the term ultra-supercritical with regards its pressure and temperature range varies somewhat.

Table 2-1: Comparison of Boiler Pressure and Temperature Ranges [4]

Pulverized Coal Power Plant	Main Steam Pressure	Main Steam Temperature	Reheat Steam Temperature	Net Efficiency HHV basis, Bituminous Coal
Subcritical	<22.1MPa 3,208psi or 221.2 Bar	Up to 565°C (1,050°F)	Up to 565°C	33%-39%
Supercritical	22.1-26MPa (3,208-3,626psi)	540-580°C (1,004-1,076°F)	540-580°C (1,004 - 1,076°F)	38%-42%
Ultra-Supercritical	>26 (3,771psi)	>580°C (>1,076°F)	>580°C (>1,076°F)	>42%
Definition of supercritical and ultra-supercritical boiler differs from one country to another. Usage of the term ultra-supercritical varies but the ranges above are generally used.				

Supercritical and Ultra-supercritical Technologies

Supercritical and ultra-supercritical technologies offer improved efficiency, proven and reliable baseload operations, and flexibility. Some of the benefits of supercritical plants can be seen in Table-2-2.

A typical "Benson Type" supercritical boiler is shown in Figure 2-6. A typical supercritical boiler start-up system is shown in Figure 2-7, and typical SC operational features are shown in Figures 2-8, 2-9, and 2-10.

Table 2-2: Benefits of Supercritical Technology [4]

Benefits	Description
Load Cycling Operation and Reliability	Plant output can be cycled with 5% to 8% per minute over a wide load range from minimum to full load (30% to 100% output); Reliability has been proven for many years with supercritical units.
Improved Load Response	Load response of 5% -15% unit output can be provided in seconds by using the energy storage capacity of the steam/water cycle. The following measures can be applied to act temporarily until normal operation has been re-established: - Operating throttle control valves - Opening an overload valve - Closing a feed water supply valve to the LP feed water heaters - Closing of steam supply valve to the final feed water heater
Start-up	Faster start-up timeis a feature of advanced plants with supercritical, once-through steam generators when designed for a three-phase start-up. First, the boiler circulation is established through the water/steam separator. Second, main steam is supplied through a main steam bypass station to the cold reheat line and hot reheat is bypassed through a reheat steam bypass station into the condenser. Third, start up of the turbine by controlled switch over from bypass to turbine operation. After a shut down, a supercritical power plant can generate minimum load in 30 minutes after boiler ignition and can reach full load in 75 minutes.
Full-Load Rejection	Full load rejection with continued operation is possible with supercritical pulverized coal plants supplied with main and reheat steam bypass systems. The boiler load is run back to its minimum stable boiler load (20%), turbine-generator provides the units auxiliary load, and the excess steam is bypassed. The power plant operates in standby mode and is then ready for re-synchronization at any time.
Efficiency and Emissions	Reduced fuel costs; Flue gas systemshave to deal with reduced emissions from supercritical plants due to the reduced amount of coal to generate the same amount of power.

Figure 2-6: A Typical 600 MW “Benson Type” Supercritical Boiler Unit

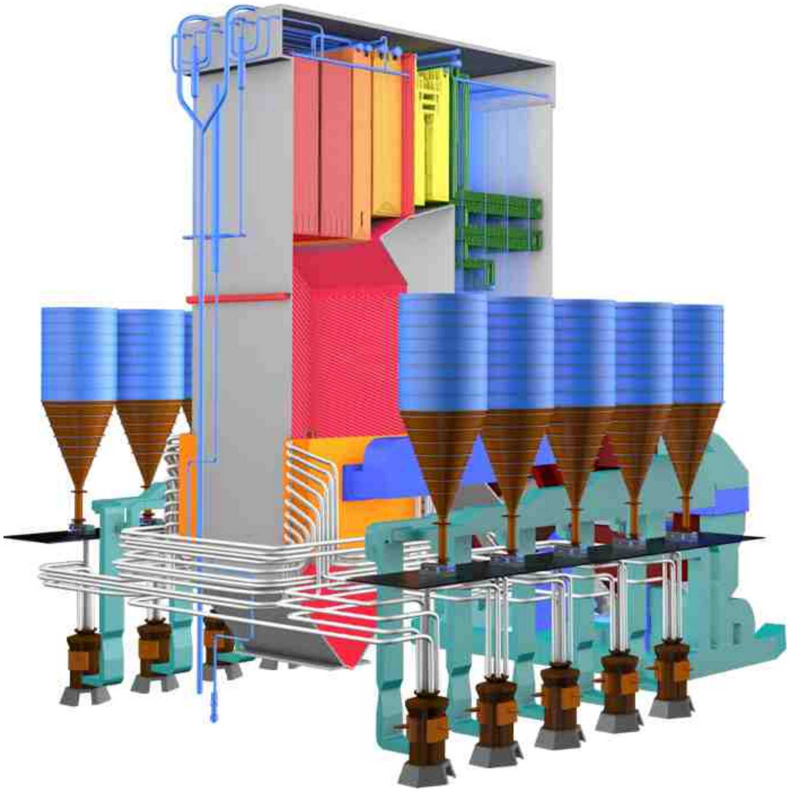


Figure 2-7: Supercritical Boiler Start-Up System (Example)

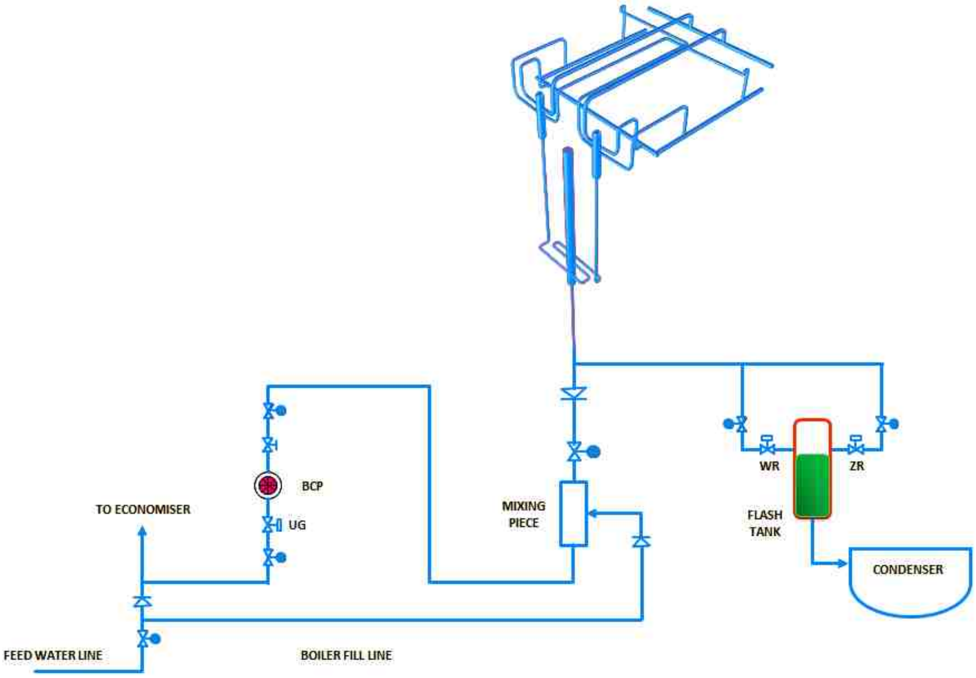


Figure 2-8: Typical Supercritical Plant Operations

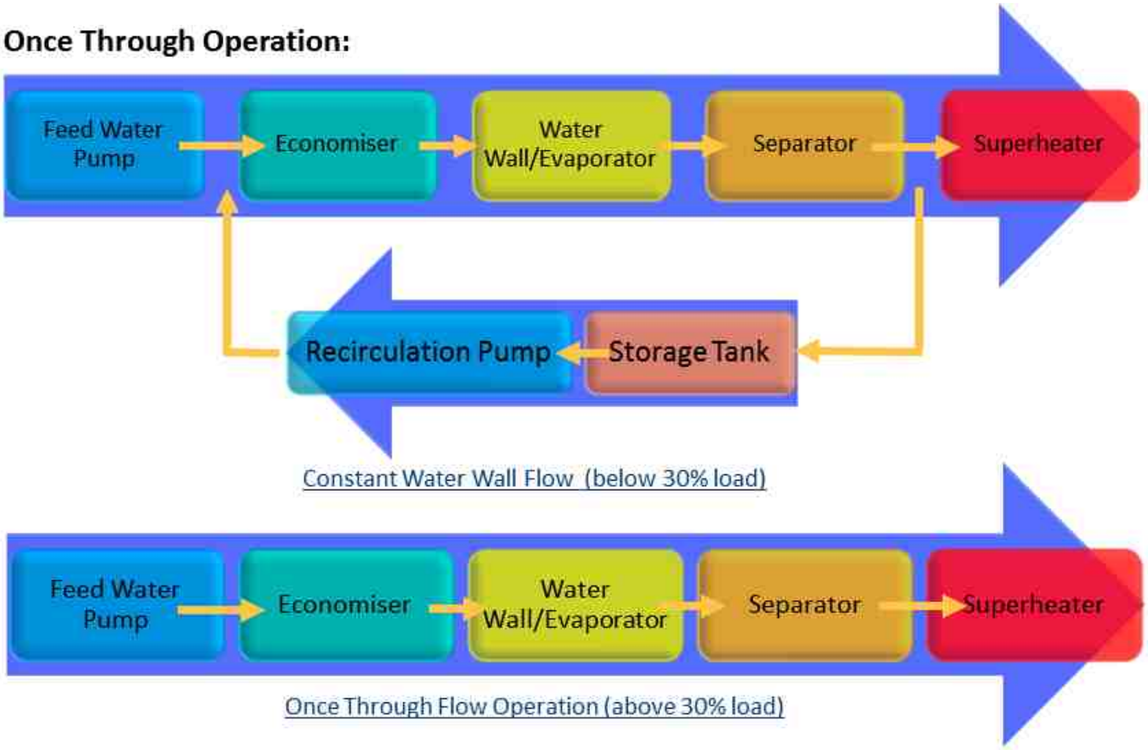


Figure 2-9: Supercritical Start-up and Recirculation

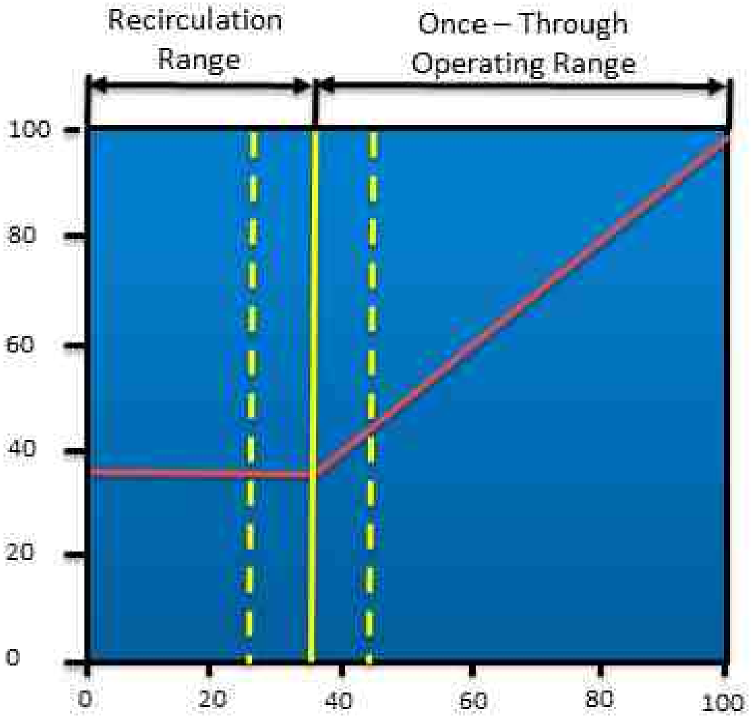
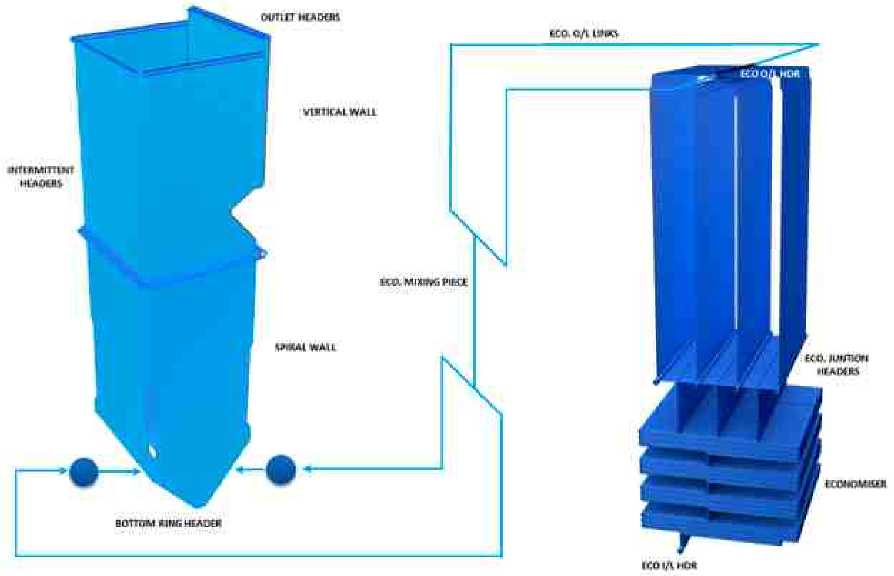


Figure 2-10: Supercritical Startup and Recirculation (Schematic)



Constant pressure Operation: above 90% and below 30%
Sliding pressure operation: 30% - 90%

2.2 EVOLUTION OF BOILER TECHNOLOGY AND THERMAL PLANT EFFICIENCY

There are many variables that influence the thermal efficiency of a power plant. Some of the major factors include:

- Site conditions:
    - Ambient conditions
    - Air and water supply
    - Condenser pressure (design)

- Plant design:
    - Cycle conditions
    - Turbine design
    - Heat transfer components
    - Plant process optimization

- Auxiliary plant equipment variation and/or inclusion of air pollution control equipment

- Fuel quality consideration – i.e., moisture, heating value and ash characteristics can have a significant impact on efficiency.

The following figures illustrate progress with the evolution of steam power station efficiency worldwide. The advancements in steam turbine designs and materials have enabled power plants to operate at higher efficiencies therefore having a significant impact on generation and greenhouse gas emissions.

A significant amount of research and progress with the development of boiler and steam turbine technology has evolved to achieve greater output through higher thermodynamic efficiency by increasing boiler system temperature and pressures. Much has been learned of material science, and application and processes for both boiler and turbine systems since the 60s. However, improvements have been adapted and research is ongoing to develop systems capable of achieving higher steam temperatures beyond 700℃ (Figure 2-11).

When evaluating the following graphs, it should also be noted that in many countries, efficiency is often expressed on the basis of lower heating value (LHV), which excludes the latent heat of vaporization of the water/moisture in the combustion process. In the U.S., efficiencies are expressed in terms of higher heating value (HHV), which includes the efficiency losses from the combustion of water and moisture in the fuel. Since LHV does not take into account the energy required to vaporize water in the fuel, the efficiency will be reported higher than it would on an HHV Basis.

Figure 2-11: Evolution of Steam Power Station Efficiency World-wide [5]

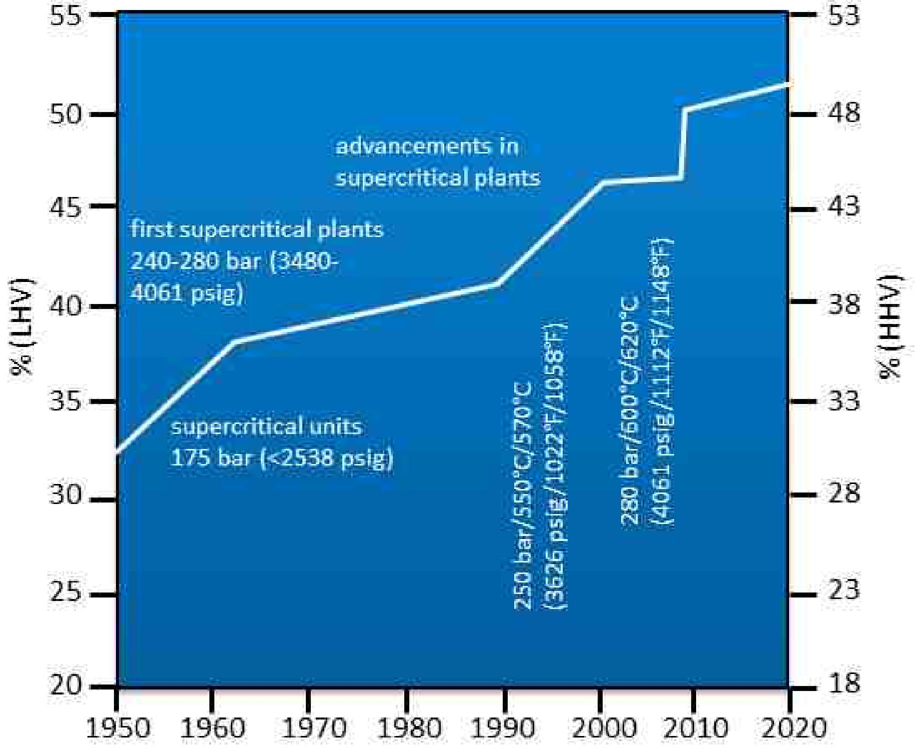
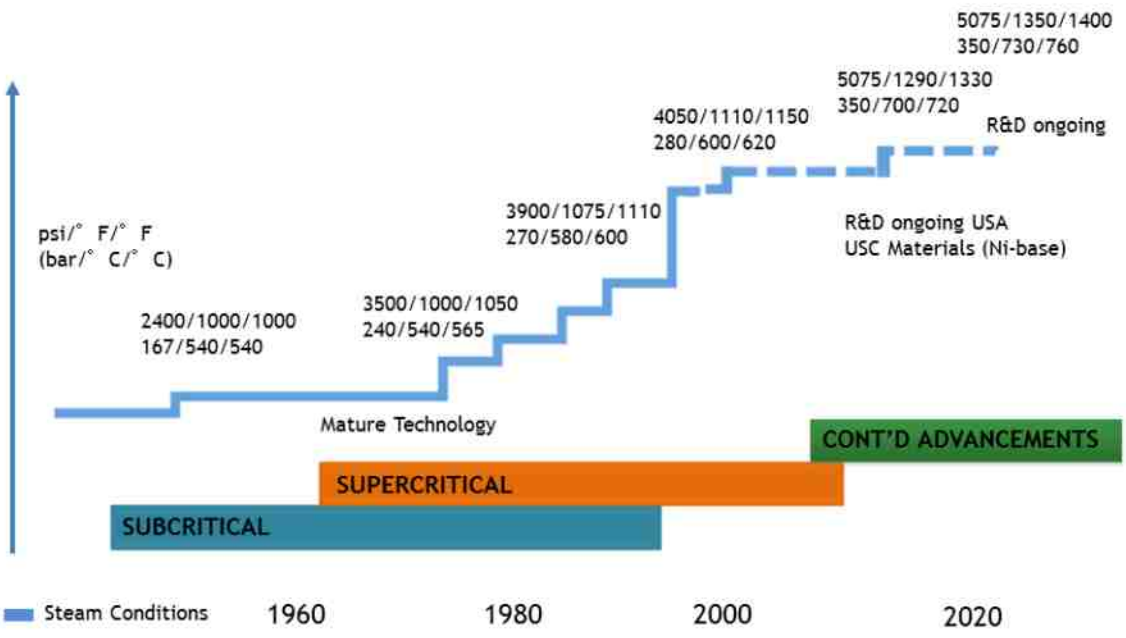


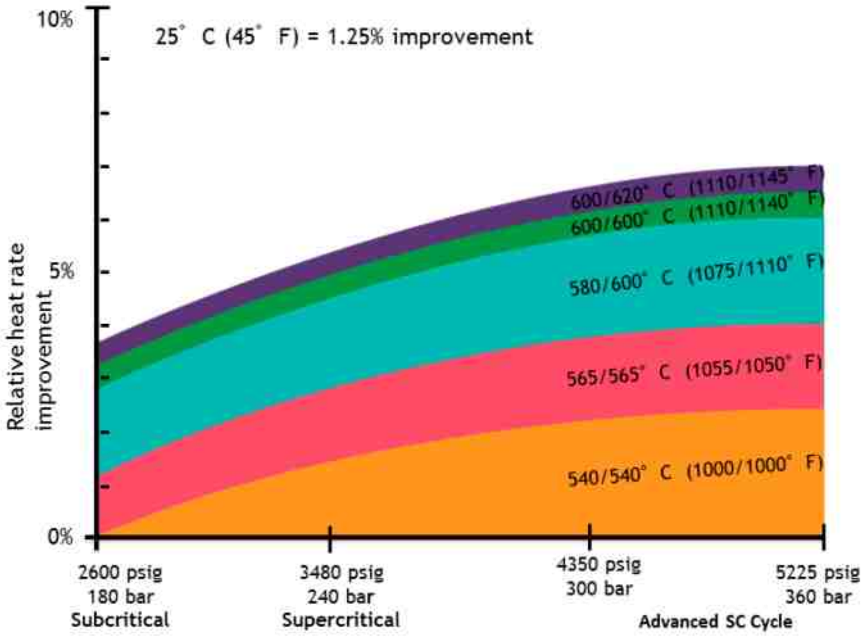
Figure 2-12: Evolution - Past and Future [4, 14]



2.3 COMMON BOILER DESIGN FEATURES

Supercritical operations at higher temperature and pressures yield a significant improvement in plant heat rate. For example, the following graph illustrates how each 25℃ increase on a single reheat (RH) unit can yield ~1.25 percent of heat rate improvement.

Figure 2-13: Varying Operations vs. Heat Rate with a Single RH [14]



As compared to many U.S. coals, most Indian domestic coals are very low in sulfur content. This lowers the risk of having fireside corrosion issues. However, most Indian coals have extremely high ash content and very low heating value. Therefore, one of the greatest challenges is with erosion due to problematic mineral ash constituents (Silica and Quartz), requiring much lower gas velocities passing through the convection tube banks, at typically 50 percent less than a higher grade U.S. coal. In order to handle the high ash Indian coals, erosion protection provisions are required on the mill and boiler components. Required mill maintenance increases significantly. Ash handling and utilization also pose additional challenges.

The size of the gas flow area increases by about 50 percent and the amount of heating surface increases due to lower heat transfer rates. Compared to a U.S. boiler firing eastern bituminous coals, the furnace of a boiler using Indian coal is about 78 percent larger in volume and about 50 percent taller. The furnace width is increased by about 38 percent, impacting the length of the nickel alloy super-heater and re-heater outlet headers. Furnace wall average absorption rates are lower while the peak rates are expected to be nearly the same [11].

To improve the availability of the coal and also improve the calorific value of fuel being fired, some Indian power stations are blending higher-grade imported coals with low-grade high ash domestic coals. By doing so, stratifications of the flue gas can create challenges with heat transfer and SC temperature control.

Because of the intense radiant heat from the firing zone, the furnace walls will have the highest heat flux of all the heat transfer surfaces. For supercritical boilers, two designs are used for furnace wall: the spiral furnace tube arrangement and the vertical tube arrangement. Both designs have their advantages and some are shown in Table 2-3 [14].

Table 2-3: Supercritical Furnace Wall Design Comparison

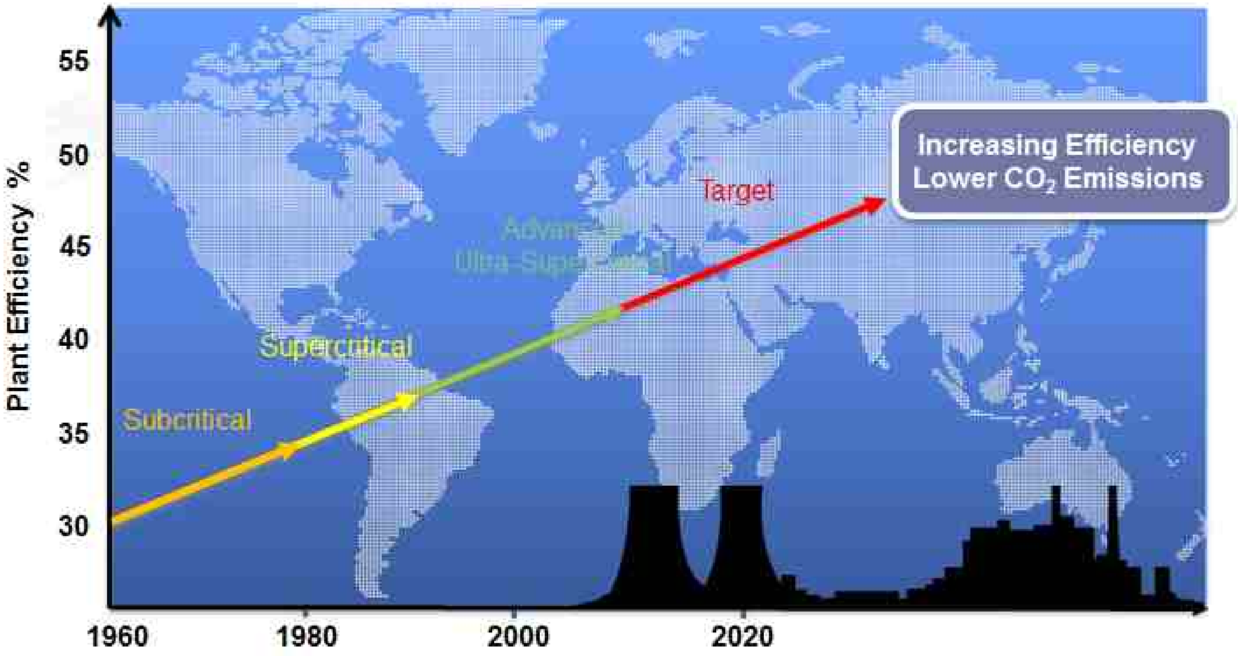
Spiral Configuration Benefits	Vertical Configuration Benefits
Averaging of lateral heat absorption variations; Each tube forms a part of each furnace wall	Simplified bent tube opening
Simple inlet header arrangement	Simple furnace water wall support system
Large number of operating experience with spiral wound furnaces	No need for the intermediate furnace wall transition header
Smooth bore tubing throughout entire furnace wall system	Lower construction labor costs
No individual tube orifices	Tube tracking for repairs is easier to identify
	Lower water wall system pressure drop
	Less feed water pump power consumption
 Spiral Water Walls (shaded section)	 Vertical Water Walls (no transition)

With its larger furnace perimeter requirement for Indian coals, and based on past experience, a spiral wound furnace design is commonly being used for the new supercritical boilers commissioned or under construction. Ideally, it is desirable not to have large variations in the material temperature of thick components such as the superheater and reheater outlet headers. Rapid cyclic temperature changes cause fatigue and reduce component life. The vertical steam separator is a thick wall component that must be located in the steam generator flow sequence considering the cyclic temperature changes of startup and load changing. The location also impacts the Benson point load where the steam generator begins to operate in once-through mode. With that said, the heating surface arrangement and steam temperature control method used is very important [13].

2.4 BENEFITS

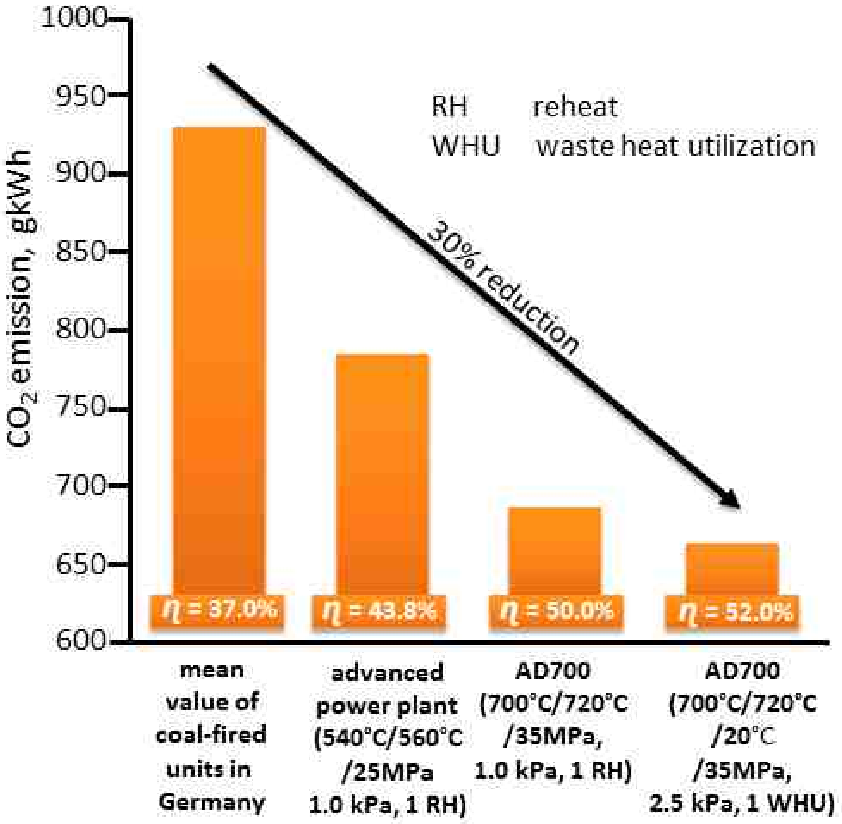
There are many benefits associated with the continued growth and development of advanced coal-fired power generation technologies. However, the two most noticeable factors are unit efficiency improvement and the corresponding environmental benefits of reduced GHG emissions with reduced fuel consumption (Figure 2-14).

Figure 2-14: Technology Advancement with Power Plant Efficiency



Considering the current and future advancements with the onset of supercritical plants being constructed in India, it is essential to have a guideline and a benchmarking process in place to help with its sustainability. Considering the challenging Indian climatic conditions, limited coal supplies, fuel costs, and new environmental regulations, technology advancement, implementation, and continued development are critical to the future of India. Sustainability can only be achieved by continued thermal efficiency improvement and a corresponding reduction in plant emissions (Figure 2-15).

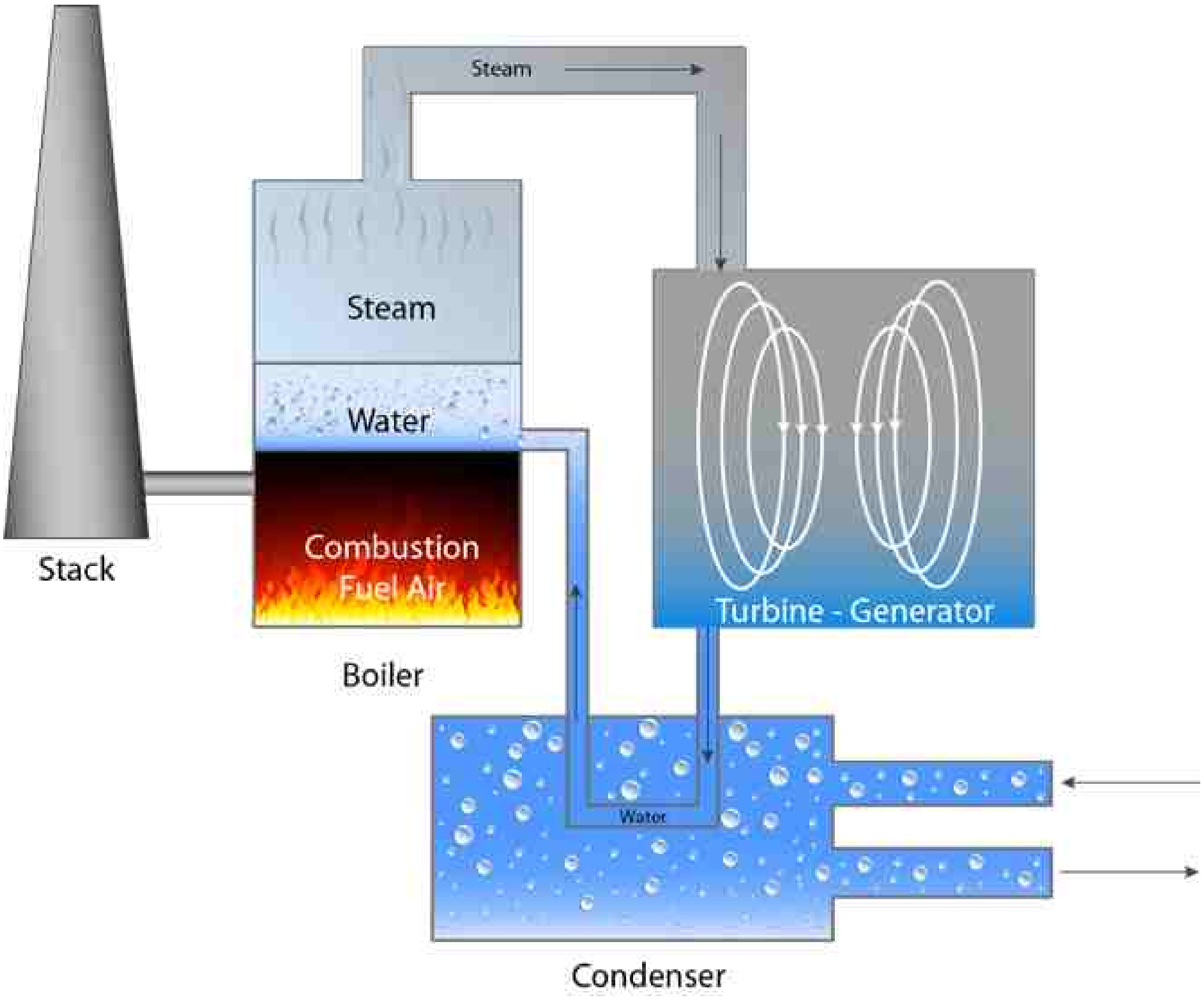
Figure 2-15: Possible CO_2 Reduction through Advanced Technologies [7]



A plant's operating steam temperature, pressure, and exit gas temperature have major influences on power plant efficiency. However, condenser pressure is the most influential factor that impacts cycle efficiency. When considering India's climatic conditions and the limited water resources to meet demand, water and fuel conservation are important elements for long-term sustainability.

In an effort to conserve fuel and water, SC boiler and turbine design improvements are instrumental. There are various opportunities for water conservation improvement when looking outside the boiler and evaluating the power plant holistically. To simplify a power plant, there are three things critical to a plant's operation. These include water, fuel, and air (Figure 2-16).

Figure 2-16: Water and Fuel Consumption Illustration

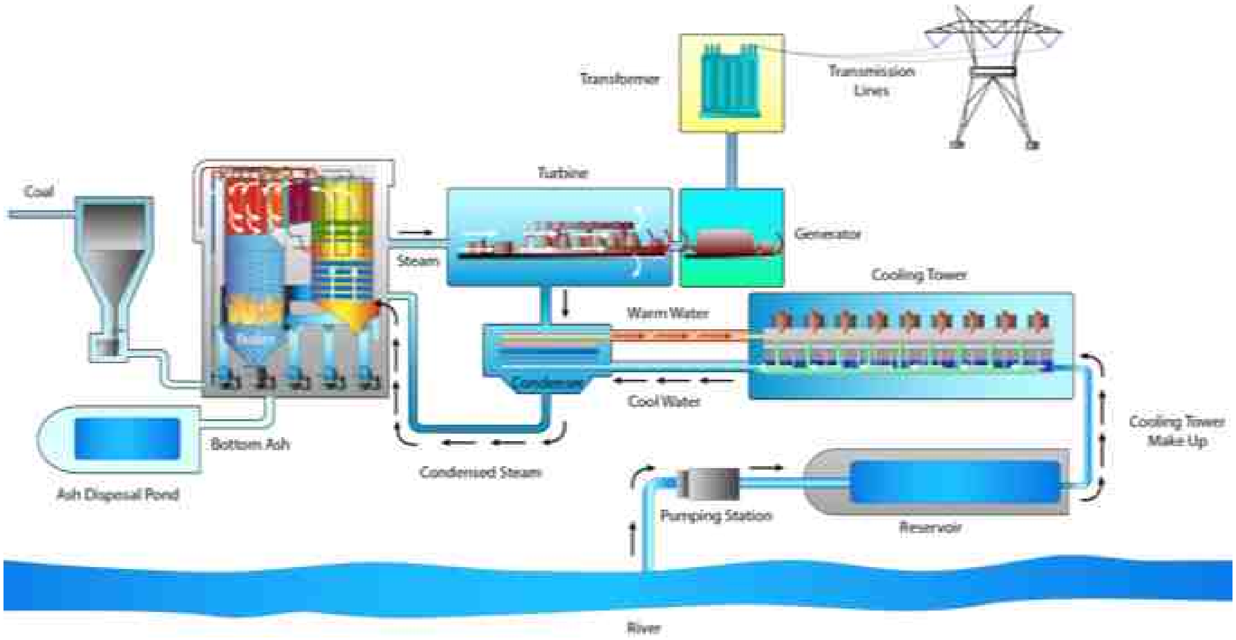


Water is used for various activities in power plants. However, most of the water used by thermoelectric plants is for condenser cooling. Plant designs vary widely as do the techniques used in the discharge of the cooling water after it passes through the condensers. These are discussed in detail in Chapter 4 – Water Consumption. Typically less water is required when cooling water is recycled through cooling towers or ponds, but a percentage of the cooling water is lost to evaporation and drift (consumptive use). Usually evaporation is between 3–5 percent of cooling water flow through the cooling tower.

2.5 CHALLENGES

A power plant can consume a lot of water for cooling and steam power generation, and its consumption must have to compete with other interests and needs such as irrigation, protected species, and fish resources. For long-term sustainability, water conservation "best practices" must be developed (Figure 2-17).

Figure 2-17: Typical Power Plant Water Withdrawal Illustration with Cooling Towers



There are a number of areas where power generation efficiency can be increased, and water use can be reduced. Some of these are as follows:

- Advancements in steam cycle efficiency (turbine and boiler)
- Reduction of water consumption and/or recycling with cooling tower and make-up water
- Advancements in condenser design
- Water treatment and waste management systems to reduce reliance on source water
- Water purification and water quality, protection against cooling water intake structures and prevention of debris damaging pumps, condenser tubing and system pressure changes
- Ash disposal (wet vs. dry).

Some of the other challenges experienced in the past and countermeasures are highlighted in Table 2-4.

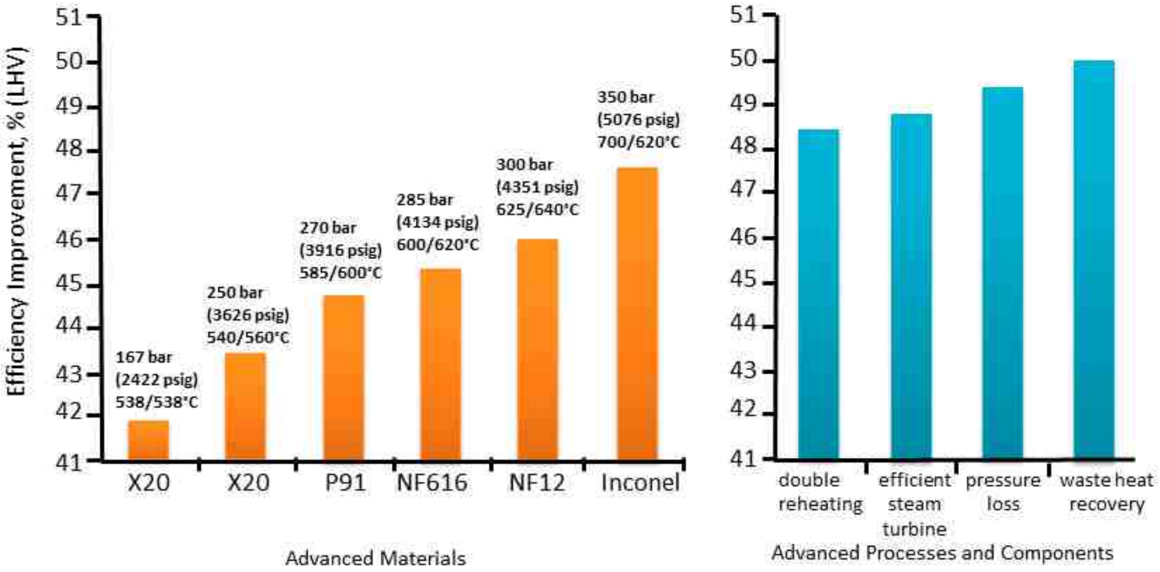
Table 2-4: Supercritical Technology Challenges and Countermeasures [4]

Problem causes in early/older supercritical pulverized coal power plants in the USA and their countermeasures [12]. Table additions by S. Storm and others (2013)

Issues	Causes	Countermeasures
Erosion of start-up valves	High differential pressure due to constant pressure operation and complications with start-up	Sliding pressure operation, simplified start-up system and low load recirculation system.
Longer start-up times	Complicated start-up system and operation (ramping operation required, difficulty establishing metal matching condition, etc.)	Sliding pressure operation, simplified start-up system and low load recirculation system.
Low ramp rates	Turbine thermal stresses caused by temperature change in HP turbine during load changing (due to constant pressure operation)	Sliding pressure operation; DCS control improvements.
High minimum stable operation load	Bypass operation and pressure ramp-up operation required	Application of low load recirculation system
Slagging	Undersized furnace and inadequate coverage by soot blower system	Design of adequate plan area heat release rate and furnace height, without division walls. Provisions of adequate system of soot blowing devices and/or water wall blowers.
Circumferential cracking of water wall tubes	Metal temperature rise due to inner scale deposit and fire side wastage.	Oxygenated water treatment. Protective surface in combustion zone of furnace for high sulfur coal, for example, thermal spray or weld overlay.
Frequent acid cleaning required	Inappropriate water chemistry	Application of oxygenated water treatment; Chemical dosing system
Lower efficiency than expected	High air in leakage due to pressurized furnace. RH spray injection required due to complications of RH steam temperature control in the double reheat cycle configuration.	Tight seal construction. Single reheat system with high steam temperature and temperature control by parallel damper gas biasing. Boiler and turbine cycle design improvements
Low availability	All the above	All the above

2.6 MATERIAL ADVANCEMENTS

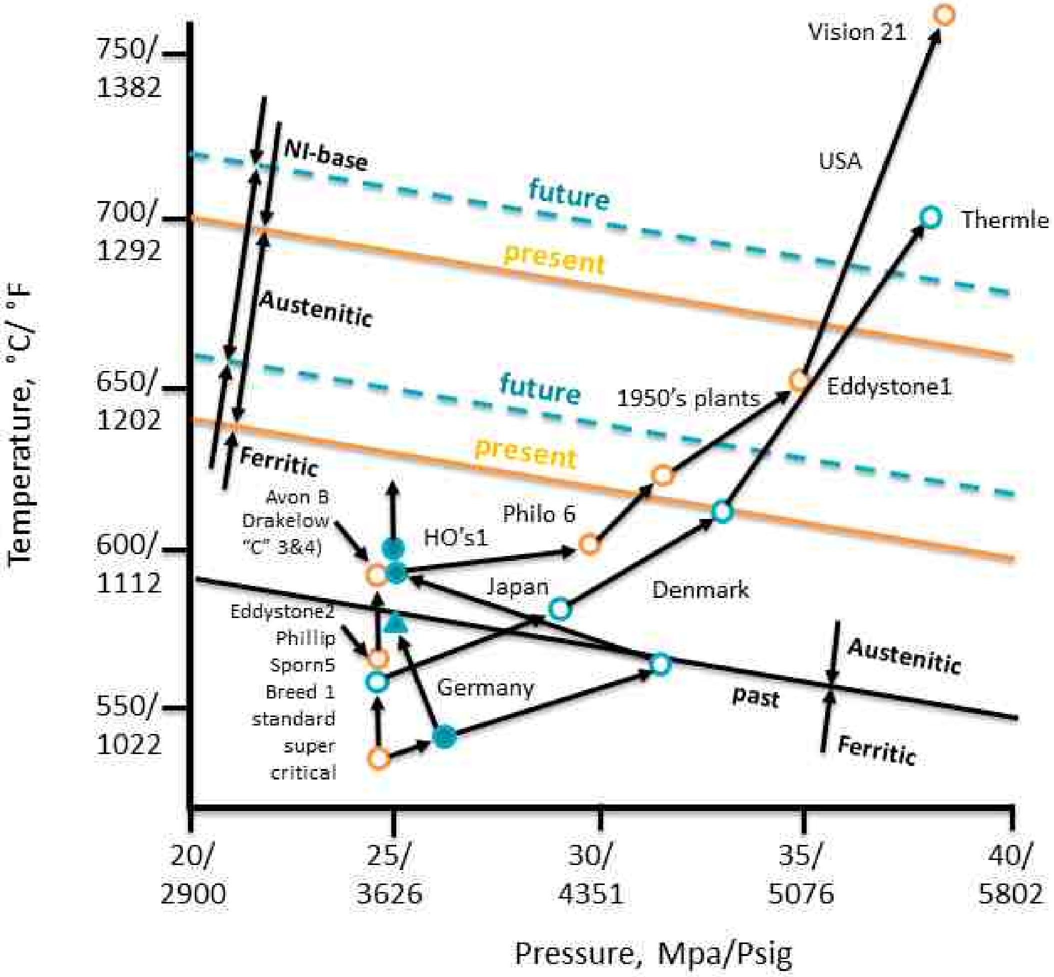
Figure 2-18: Efficiency Improvements of Pulverized Coal Power Plants [6]



Higher steam pressures and temperatures demand higher strength alloys. Progress has been made in the development of new alloys needed for advanced and USC (+700°C) plants. Boiler materials development programs to address needs and qualification by design codes have been underway for more than 10 years in Europe (Thermie AD700) and the U.S. DOE Coal Development Office (DOE/OCDO). Japan is also developing materials, and conducting laboratory and pilot scale tests as well. The advancement to 700°C steam temperatures for coal firing represents an increase of 166°C (300°F) above the average predominant operating experience. The current state of-the-art plant uses 600°C (1112°F) technology, which is not widely applied so that industry experience is lacking or limited. Therefore, introduction of 700°C USC technology has to be first proven by conducting development programs that test and demonstrate that the risk is acceptable for a very capital intensive industry. Referencing B&W's experience and pioneering technology introductions with American Electric Power Philo 6 (31MPa, 621°C, 565°C, 538°C) in 1957, and Philadelphia Electric (now Exelon) Eddystone 1 (34.5MPa, 649°C, 565°C, 565°C) in 1959, are good examples of the need for extensive research and development prior to commercialization (Figure 2-18).

Figure 2-19 illustrates past, present and future utilization ranges for ferritic steels, austenitic steels and Ni-based alloys in supercritical power plants. As shown, the Ni-base alloys are clearly required for the highest temperature components of 700°C pulverized coal plants. Continued R&D, standardization and specification for material advancements are needed, and should be considered for improving not only creep strength, but also boiler design changes to handle erosion with high ash Indian coals. Material selection and process for ensuring reliability is critical for preventing thermal fatigue, high temperature corrosion and steam oxidation.

Figure 2-19: Past, Present and Future Utilization Ranges for Ferritic Steel, Austenitic Steel, and Ni-Base Alloys In Supercritical Power Plants [8]



The efficiency improvement with ultra-supercritical technologies is obvious. However, the challenges demand continued improvement and development of high strength alloys, along with the best practices to ensure, mitigate, and/or reduce the frequency of metallurgical failures.

With the massive growth of the India's future power generation, there will be many challenges in adopting SC technologies. Similar to the way the Electric Power Research Institute (EPRI) has been created in the U.S. to help resolve problems; India will also require a knowledge center to overcome future challenges.

This manual is provided to share experiences, lessons learned and best practices that are currently being utilized.

Startup and Shutdown 3.0

3.0 STARTUP AND SHUTDOWN

3.1 SUMMARY

While supercritical units have been operating for many decades, supercritical Benson boilers have not been the choice for many utilities in the U.S. The situation, however, has changed recently. For example, Duke Energy and American Electric Power (AEP) have selected a Benson design for their supercritical units at Cliffside and Turk plants, respectively. Other U.S. utilities have done the same, as the Benson design has distinct cyclic operation advantages.

It appears that the new generation of supercritical units in India will be mostly of the Benson design. The Benson design offers many superior features when compared to the earlier generation of supercritical units. Speed of startup, fewer thermal transients, the simplicity of the startup system, the ability to easily cycle load, and improved reliability all favor the use of a Benson design.

In India, the units will not be cycled nearly as much as in the U.S. India has a generation deficit of such proportions that all of the supercritical units will be considered “base loaded” for the near future. However there will come a time in the life of these units that they will see some cycling to lower loads and even some reserve shutdowns at certain times of the year. The Benson design will allow for this type of future cycling style of operation.

In the U.S., even the most efficient of the earlier class of supercritical units are required to cycle and experience routine shutdowns periodically. Even the newer class of supercritical units will need to cycle to lower loads on a routine basis. A number of recent combined cycle plants have followed this trend. Because of this, the supercritical plant operators are very experienced at hot and warm starts as well as shutdowns.

3.2 BEST PRACTICES

The following is a list of best practices for supercritical unit startup and shutdown operation:

Alarming and Sequence Monitoring

The “sequence monitoring” system was first utilized by a leading U.S. utility in the mid-1960s with the advent of digital/analog computers. At that point in time computers were used for only very limited control functions. The computer allowed for close monitoring of all the startup steps by inputting analog and digital data into a monitoring computer that generated an operator display. Still, many inputs were required to be manually entered into the computer. There was a series of windows that were displayed for the various steps in startup such as “fill the hot well” or “start the condensate system" ending with "synchronize and load the unit". The operator could not move to the next window until he/she had the previous window "lit". There was also a sequence monitor for unit shutdown. As computers and instrumentation became more advanced, the sequence monitor became more automated. In recently built power plants, comprehensive monitoring and automation as well as digital control systems exist allowing for much more automated sequence monitoring systems to be utilized. It is a best practice to have an "online startup and shutdown sequence monitoring system" that allows operators to assure that every startup and shutdown step is correctly done with minimal errors.

The integrity and understanding of alarms is very important, especially during the startup process. Current technology enables the addition of many more alarms at a minimal cost, oftentimes providing excessive and redundant information to the operator. The ANSI/ISA-18.2-2009 document on Management of Alarm Systems for Process Industries provides a very complete methodology for addressing alarm management. The process starts with the establishment of an "Alarm Philosophy". This serves as the framework to establish the criteria, definitions and principles for the alarm lifecycle stages. The methods for alarm identification, rationalization, classification, prioritization, monitoring, management of change, and audits are all specified. An alarm philosophy document ensures that facilities can achieve:

- Consistency across process equipment,
- Consistency with risk management goals/objectives,
- Agreement with good engineering practices, and
- Design and management of the alarm system that supports an effective operator response.

This process can be further enhanced by providing a resource for operators, such as a "pop-up" window for displaying information. This information includes a much longer and more descriptive alarm message – i.e., an explanation of the consequences of an improper response or no response, and the proper response(s).

Benson Technology for Smooth Transition from Subcritical to Supercritical

Many supercritical plants built in the U.S. and elsewhere in the 1960s and 1970s could not be easily transitioned from subcritical to supercritical operation. The waterwalls were required to be always at supercritical pressure to avoid tube failure due to overheating caused by departure from nucleate boiling (DNB). The schemes for transitioning from subcritical operation to a true supercritical operation relied on a series of valves taking very high pressure drops. This is a major area of maintenance concern with these plants. In addition, cycling to significantly lower loads or the use of sliding pressure in the waterwalls was not possible. The Benson boiler design allows for smooth transition from the subcritical to supercritical regime and easily allows for sliding pressure in the steam generator.

A challenging point in the Benson cycle startup occurs shortly after initial firing as steam bubbles begin to form in the waterwalls, creating a water swell. Water relief line valves from the water separator must be sized and controlled to enable rapid stroking for quick response to water swell shortly after initial firing. In the event that the boiler circulating pump is not available, these valves must also be sized and controlled to be capable of handling increased water flows during startup.

The Addition of HP and IP Turbine Bypass

Earlier units in the U.S. were not equipped with turbine bypass systems for the HP and IP turbines. With the addition of these systems much more flexibility in the firing of a boiler can be obtained. Accommodation of unit excursions can be more easily handled even to the extent of not tripping the boiler during a full load rejection.

Rolling and Synchronizing by First Admitting Steam to the IP Turbine

Again earlier supercritical and subcritical units in the U.S. always utilized the HP turbine for rolling up to rated speed and synchronization. The concept of first admitting steam to the IP turbine can dramatically reduce the stresses placed on a turbine. This design practice enables warming of the steam prior to HP turbine admission, preventing the damage to heavy walled sections from rapid cooling previously experienced during hot starts.

For turbine cold startup, the rate at which turbines can be warmed and loaded is provided by the OEM guidance, but a general rule of thumb to prevent fatigue is 80-95°C/hr.

Ability to Startup Without a Boiler Circulating Pump

On some earlier vintage supercritical units in the U.S., the boilers were required to have a boiler circulating pump (BCP) in operation during initial firing and up to a certain load at which time the BCP could be shut down. On the newer Benson designs boiler circulating pumps are used under normal startup conditions. At times the boiler circulating pump may not be available due to maintenance or failure, necessitating an alternate startup process. Shown below are some of the changes in the operating variables that occur when the BCP is out of service:

- Feedwater flow increases (requiring additional firing to provide the increased furnace heat absorption)
- Only oil (or gas) firing must be used to about twice the normal load
- Delaying placing the first mill in service to avoid excessive localized heat flux
- Putting lower burners in service to increase the distribution of furnace heat absorption
- Pegging of the heaters with auxiliary steam to maximize the feedwater temperature
- Furnaces with gas biasing dampers should be set up to maximize economizer heat absorption
- Water flow from steam separator to condenser will increase significantly
- Startup time and cost will increase.

Minimization of Startup Time

Water chemistry is a primary area of concern during unit start-up. Good practices include:

- Practice good water chemistry techniques
- Assure condensate polishers are well maintained and operate with maximum cleanup flow throughout startup
- Inspect vessels to ensure cleanliness during outages.

For conventional supercritical units, on a cold startup, after turbine roll, while furnace gas probe temperature constraints are still limiting firing, procedures often recommend setting HP flash tank pressure set-point to 70 kg/cm^2 in preparation for transfer to once-through operation. By maintaining this at a lower set point, typically 40 kg/cm^2, additional steam is available to supply minimum flow required at the superheater.

At this point in the startup, the HP flash tank steam is used for two purposes –turbine steam flow and pegging heaters. Since turbine stress probes typically limit generation increases, available steam should first be used to increase turbine steam flow in accordance with stress probe limitations. All remaining steam should be used to peg the heaters. Since firing cannot be increased until minimum flow is attained through the superheater satisfying the permissive to remove furnace gas probes and raise gas temperatures above 538°C (1,000°F) efficiency is very important, so HP flash tank dump valve opening should be minimized. To further expedite satisfying this permissive, HP flash tank pressures should be maintained at a reduced set-point to maximize steam available.

Boiler and Turbine Cooling

Turbine Cooling

Turbine cooling can best be done by installing removable insulating blankets on the HP and IP shells. These blankets can be removed shortly after shut down and fans can be placed around theses shells to circulate air. This can take days off the time that is required to remove the turbine from barring gear at the beginning of a turbine outage. This can also be a cost saving since these blankets can be reused. Also maintaining vacuum on the condenser and opening turbine drains are recommended. In some cases, compressed air can also be injected into the turbine sections.

It is important to verify the acceptable cooling rates allowed by the turbine manufacturer and do not exceed these. Excessive cooling rates can cause uneven cooling of the turbine components resulting in rubs of turbine blades and seals, which will result in locked turbines and poor efficiency due to seal and blade damage. Some turbines are so sensitive to cooling rates that damaged blankets or fanning can cause humping of the shell and locked rotors. Closing select turbine drains during cooling process is required on some machines due to circulation of cold rogue steam through sections of the turbine causing uneven cooling and rubs. Shaft eccentricity should be monitored very closely when cooling turbines.

Boiler Cooling

In subcritical units, boiler cool down is limited generally by the large wall components and mainly the drum. Since the drum is eliminated in supercritical units, faster cool down rates can be realized by adopting the following best practices:

- On a balanced draft unit, open all access doors on the front and back passes of the boiler and continue to operate the induced draft fans.

- On a forced draft unit, continue fanning and shut down the air heater rotation when exit gas gets below 70°C to speed cooling.

- Open all of the boiler penthouse doors and install fans to remove the heat. In addition, keep the boiler penthouse seals in good condition to prevent large accumulations of fly ash. Many units in the U.S. have installed iso-membrane seals in the penthouse that have less tendency to crack and allow fly ash ingress. In the U.S., independent companies are contracted to vacuum fly ash accumulations from the penthouse and other dead air spaces in the boiler.

- Force cooling with the feed pump while fanning accelerates cooling of the steam generator - when the unit is removed from service due to a scheduled outage, this can be accomplished by reducing the unit load to zero, tripping with the reverse power relays and retaining the boiler feed pump in service, utilizing aux steam to peg the deaerator and to drive a steam driven pump. To accelerate cooling after a trip-out, the pump can be restarted. This can be accomplished through the use of High Pressure Flash Tank (HPFT) steam followed by aux steam, or crosstie steam from another unit for deaerator pegging. Condenser vacuum must be maintained during this period. When pressure on the steam generator has adequately decreased, the condensate booster pump should be placed in service to complete the cooling process.

- The alternative protocol of cooling the unit by fanning only cools the tubes, leaving the headers hot. Hot restarts shock the headers with cold water. Force cooling with the BFP and booster pump has the added advantage of cooling the thick-walled piping and headers in addition to the tubes.

- During the boiler cooling process, pressurize the superheater and dry reheater with air after the pressure bleeds down and before gas to the air heater drops below 175°C to minimize pitting and exfoliation, and tube plugging. This also provides the benefit of reducing superheat boil-out time during startup.

- An important part of the shutdown/startup process involves pressure testing the steam generator to identify any leaks that were present during operation or have developed during the cooling process. A liquid pressure test is the preferred method of confirming that no leaks are present. Typically, hydrostatic tests do not exceed operating pressure to avoid excessively stressing equipment, so no special measures are required for the safety valves. Caution should be exercised to avoid quenching by ensuring that the metal has cooled to within 50°C of testing water temperature, and that the testing water exceeds 20°C.

- A pneumatic test of the superheater and reheater using air or nitrogen, as applicable, of 3 to 6 kg/sq.cm is effective for locating leaks.

- Safety valve compliance requirements must be met and certified for operation. The following safety valve test guidance is provided as a best practice:

  Hydrostatic testing of safety valves is a process required to ensure the safety of the steam generator. Most U.S. jurisdictions do not have a required interval for testing safety valves; however, intervals are established in concurrence with the jurisdictional authorities. Inspection intervals may vary from annually to in excess of ten years for some safety valves. Although the inspection interval is not mandated, many jurisdictions have specific code requirements for inspection, testing and repair. These requirements vary over a wide range; some require the work to be performed by an organization that has a National Board Certificate of Authorization for use of the "VR" stamp; others require an OEM authorized facility, and others have less stringent requirements.

The testing process is best performed prior to planned outages utilizing a “hydroset device”. Valves should be tested prior to the unit shut-down for a planned outage to verify set point and check valves for operation and required repairs. If a valve is tested and operates correctly, then no further action needs to be taken. The valve need not be disassembled if it has proven to be functionally correct by the test. If valves are reconditioned or repaired, set points need to be tested and verified as soon as possible after the unit returns to service.

Although the safety valve test should be performed by an organization that has a National Board Certificate of Authorization for use of the "VR" stamp, a typical procedure involves popping the valves with a combination of boiler steam pressure and calibrated hydraulic jack force. The boiler is operated at normal temperature and pressure. The calibrated hydraulic jack is connected to the valve stem. Pressure on the jack is increased until the valve starts to open. The effective popping pressure is calculated by (Popping pressure = boiler pressure + jack force/safety valve feather/seat area). No correction is required for temperature. Blowback is not checked.

Minimization of Oil Use on Startup

Placing pulverizers in service early in the startup can significantly reduce oil usage. U.S. plants are typically designed with steam generators that can withstand the more localized heat input generated by placing a bottom pulverizer in service early in the startup process, and many modern units have turbine bypass capability enabling flow through all superheaters to further speed startup. Pulverizers are typically placed in service when primary air temperatures exceed 65°C, which generally occurs at 10-15 percent fuel flow, about 3-4 hours after light-off, and prior to synchronization. Unnecessary oil lighters are then removed from service.

Boiler Temperature Management

Best practices and recommendations for management and control of boiler temperatures consist of the following:

- Temperature control should be tuned to avoid exceeding tube temperature alarm limits. Operating outside these limits will shorten tube life.

- Boiler and turbine manufacturer design ramp rates should not be exceeded on startup. Limits should be adhered to since operating at rates that exceed these limits will shorten equipment life, and cause premature failure.

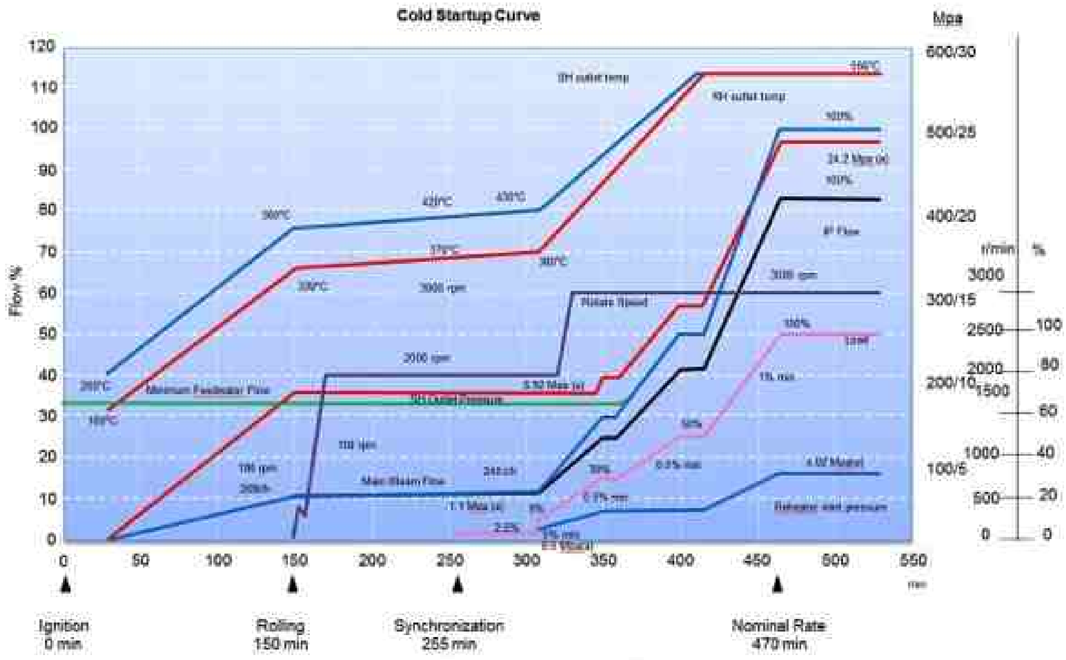
- Since both temperature and load significantly lag fuel changes, rate action should be incorporated into the controls providing additional fuel on load changes. This concept can be further enhanced by rate action on the primary air to sweep extra fuel out of the pulverizers during load changes.

Sufficient heat flux sensors and thermocouples should be installed in furnace to enable intelligent slag blowing and monitoring of headers and select superheater tubes. Typically at least the hottest two tubes are monitored on a minimum of 15 percent of the superheater platens.

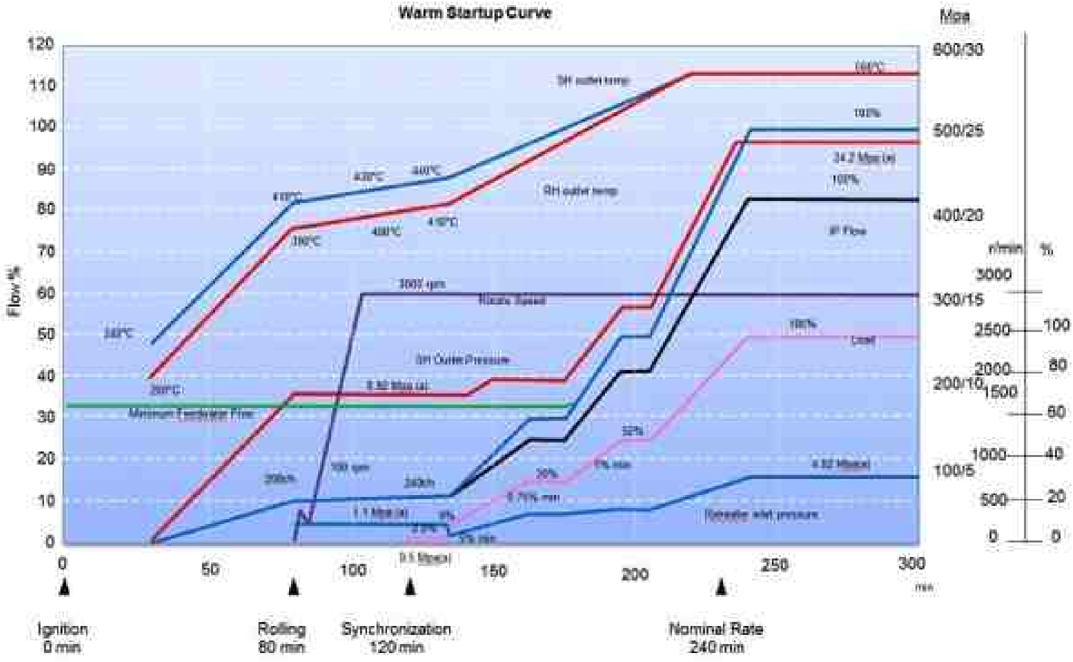
Start up curves

The following four figures are typical start up curves for Benson designed plants:

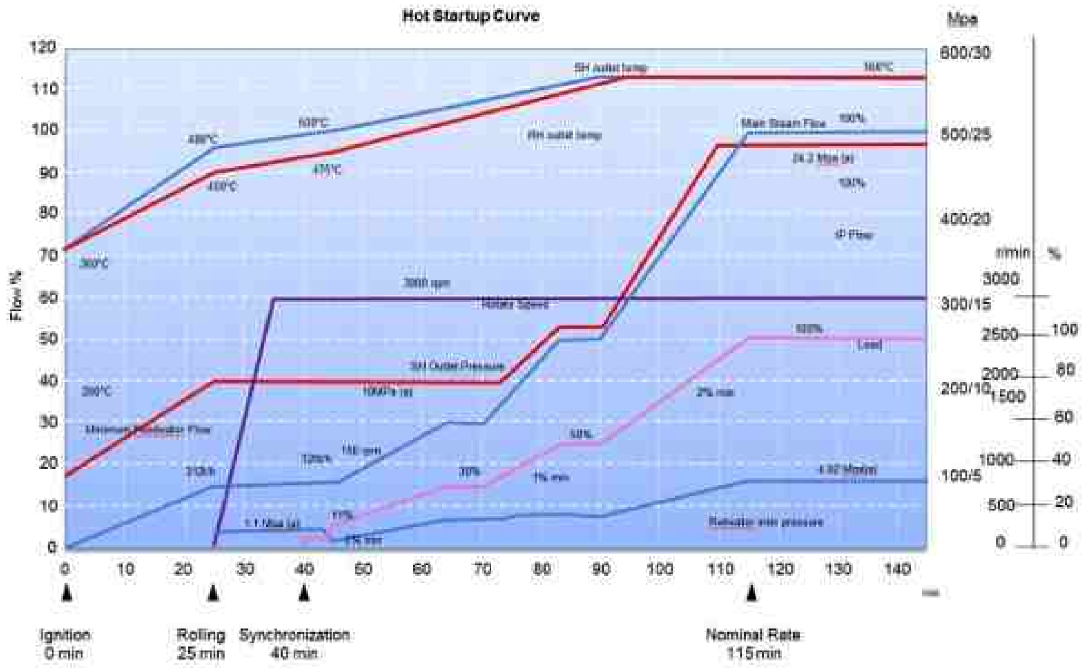
Figure 3-1: Typical Startup Curves for Benson Designed Plants



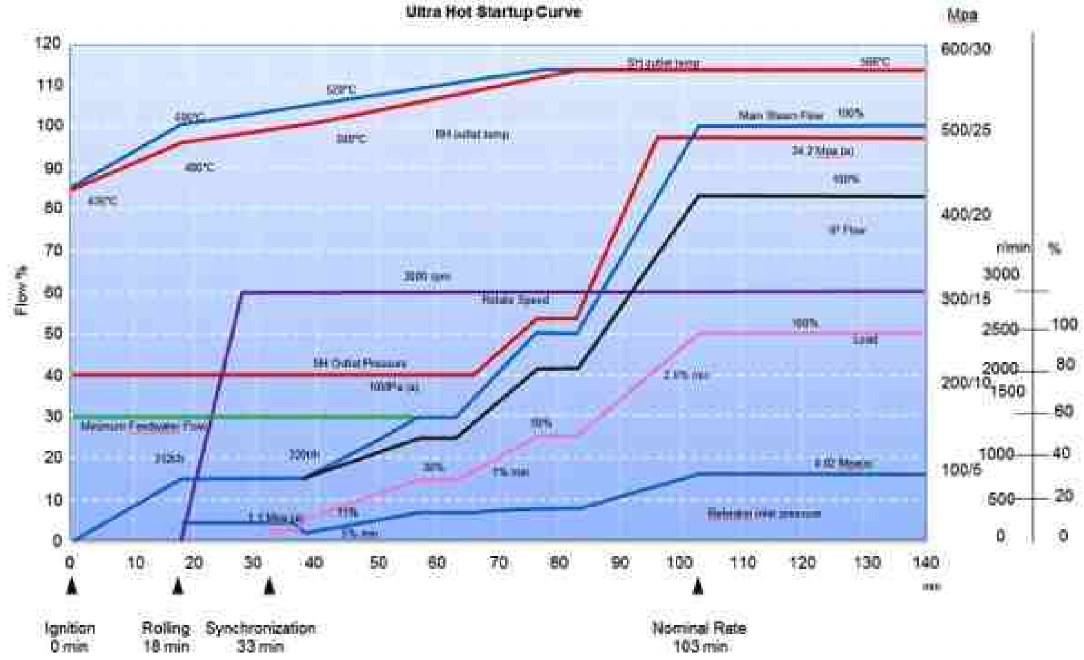
All flows are figured with the percent of NR flow



All flows are figured with the percent of NR flow



All flows are figured with the percent of NR flow



All flows are figured with the percent of NR flow

Water Consumption 4.0

4.0 Water Consumption

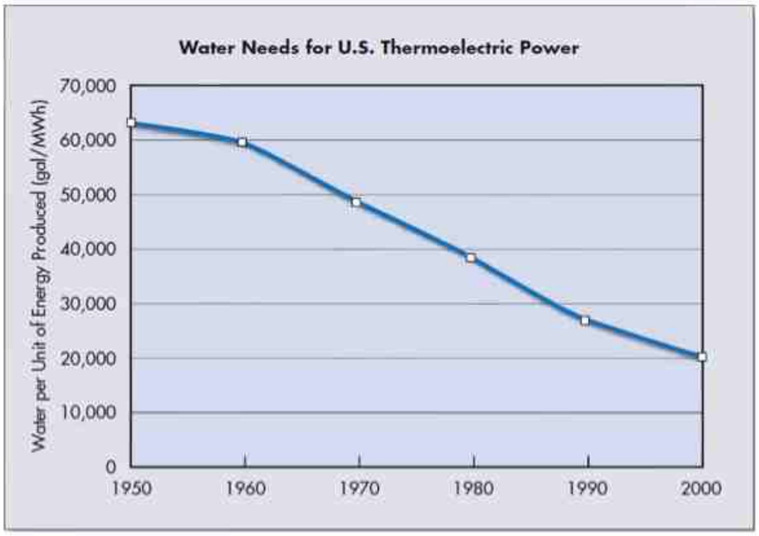
4.1 SUMMARY

Water availability for power production is becoming constrained in many parts of the world. The challenges faced in India are no different from those from the rest of the world. Today, a wide variety of processes and technologies are being deployed to recover, recycle, and re-use water. The three major areas where water is consumed in a power plant include: steam production; condenser cooling; and bottom ash transport. Wet or dry flue gas desulfurization (FGD) systems for sulfur dioxide removal from the flue gas also consume a significant amount of water. Plant designs can vary depending on site water availability. However, by adopting "best practices," water consumption could be significantly reduced at most sites.

The first step in water reuse and conservation is to route the cooling water blow down to a disposal pond, from which treated water is recycled back into the plant. Slurry from ash and gas handling systems can be handled in a similar fashion. Other steps that can be adopted to promote water re-use include using waste water treatment, reverse osmosis, evaporation, and zero liquid discharge systems.

This chapter starts with an overview of water consumption issues and then breaks down the major areas where water is consumed in different processes. Best practices that can be adopted to conserve water are discussed, followed by case studies from plants in the U.S. that operate zero liquid discharge systems.

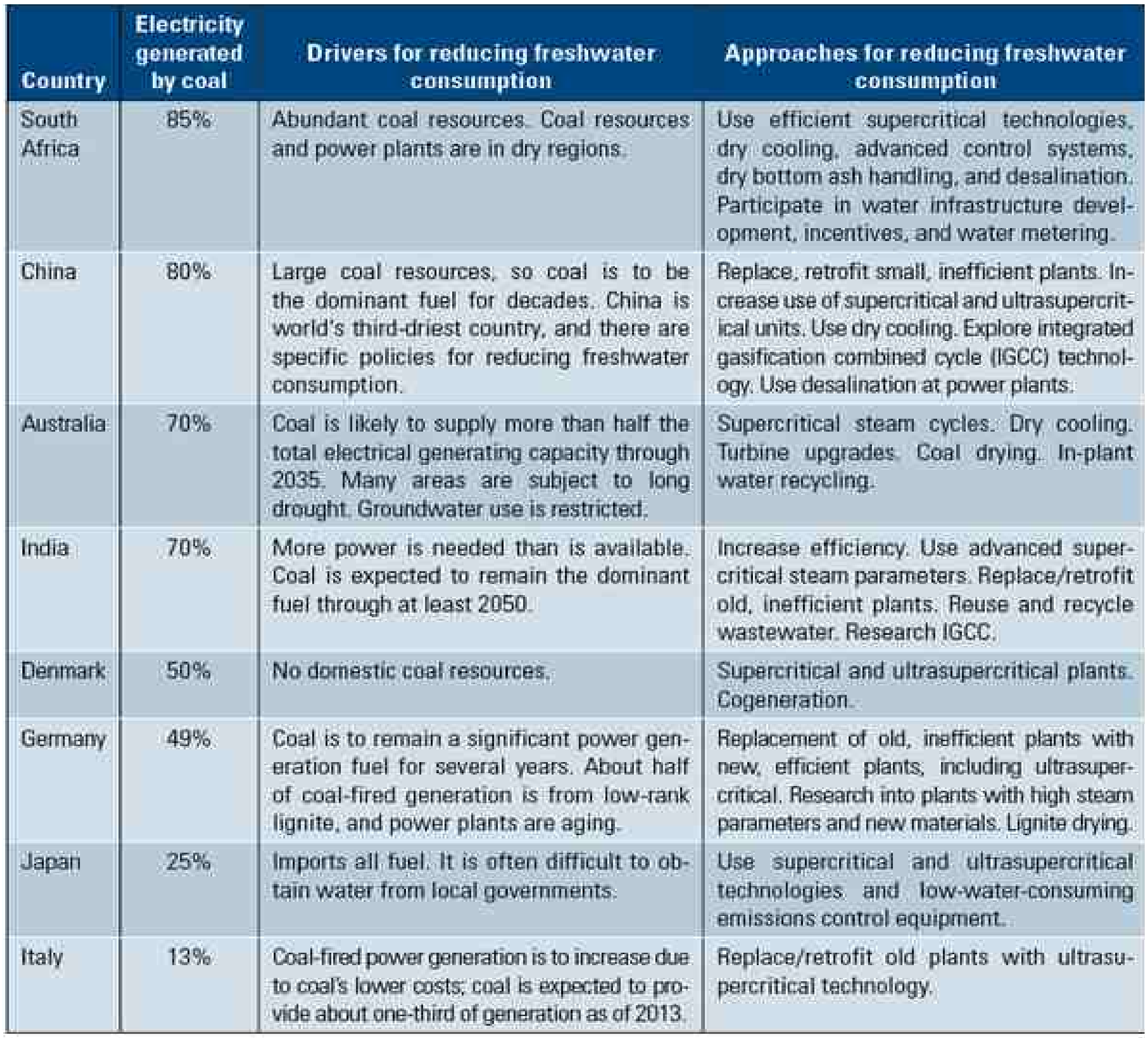
Figure 4-1: Water Needs for U.S. Thermoelectric Power Plants



The efficiency of water usage in the U.S. power plants has greatly improved over the past fifty years. Although the volume of water withdrawn for power plant usage has increased by a factor of five since 1950, the amount of power generated actually has grown at a factor of fifteen. As a result, the water withdrawn per megawatt hour has decreased by more than two thirds (Figure 4-1) [6]. This reflects a significant improvement in water reuse and conservation, and improvement in overall plant efficiency in the U.S.

The challenges faced in India are no different than those faced around the world, as shown in Table 4-1.

Table 4-1: Water Issues and Challenges for Power Generators POWER Magazine - July 1, 2013 [4]



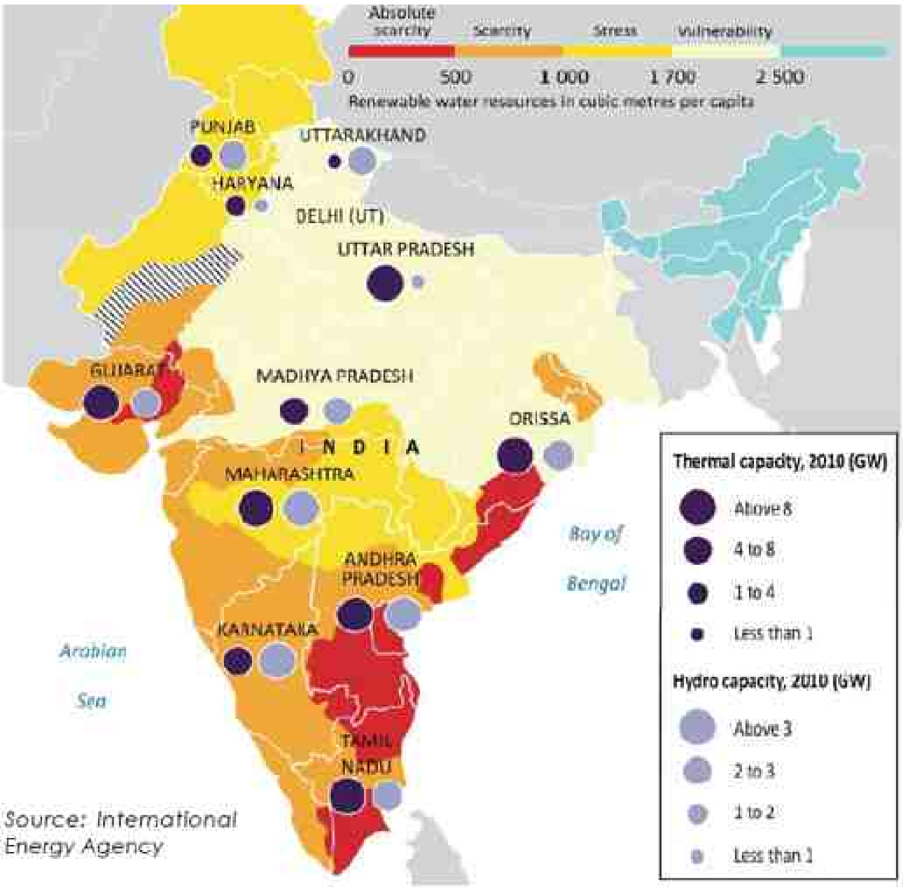
Country	Electricity generated by coal	Drivers for reducing freshwater consumption	Approaches for reducing freshwater consumption
South Africa	85%	Abundant coal resources. Coal resources and power plants are in dry regions.	Use efficient supercritical technologies, dry cooling, advanced control systems, dry bottom ash handling, and desalination. Participate in water infrastructure development, incentives, and water metering.
China	80%	Large coal resources, so coal is to be the dominant fuel for decades. China is world's third-driest country, and there are specific policies for reducing freshwater consumption.	Replace, retrofit small, inefficient plants. Increase use of supercritical and ultrasupercritical units. Use dry cooling. Explore integrated gasification combined cycle (IGCC) technology. Use desalination at power plants.
Australia	70%	Coal is likely to supply more than half the total electrical generating capacity through 2035. Many areas are subject to long drought. Groundwater use is restricted.	Supercritical steam cycles. Dry cooling. Turbine upgrades. Coal drying. In-plant water recycling.
India	70%	More power is needed than is available. Coal is expected to remain the dominant fuel through at least 2050.	Increase efficiency. Use advanced supercritical steam parameters. Replace/retrofit old, inefficient plants. Reuse and recycle wastewater. Research IGCC.
Denmark	50%	No domestic coal resources.	Supercritical and ultrasupercritical plants. Cogeneration.
Germany	49%	Coal is to remain a significant power generation fuel for several years. About half of coal-fired generation is from low-rank lignite, and power plants are aging.	Replacement of old, inefficient plants with new, efficient plants, including ultrasupercritical. Research into plants with high steam parameters and new materials. Lignite drying.
Japan	25%	Imports all fuel. It is often difficult to obtain water from local governments.	Use supercritical and ultrasupercritical technologies and low-water-consuming emissions control equipment.
Italy	13%	Coal-fired power generation is to increase due to coal's lower costs; coal is expected to provide about one-third of generation as of 2013.	Replace/retrofit old plants with ultrasupercritical technology.

Global investment. Efficiency improvements along with supercritical and ultrasupercritical technologies are gaining favor in countries that face water constraints. *Source: NETL*

4.2 WATER AND ELECTRICITY OVERVIEW FOR INDIA

Water availability is a major concern for India and for future thermal power plants (Figure 4-2). Despite the water constraint, India's continued economic growth is creating a serious need for increased electric supply. With massive growth in power generation, India will need substantial amounts of water to accommodate the increase in power generation. Rapid and continuing economic and population growth will further stress water resources as demand for electricity continues to increase. This is especially true with agriculture and electrical generation competing for limited water resources [1].

Figure 4-2: Water Constraint Illustration



Source: International Energy Agency

Water is used for various activities in power plants.

Some of the major areas where water is consumed include:

- Steam production
- Condenser cooling
- Bottom ash transport (with wet systems which convey ash to an ash pond)

Other areas referenced as "Off Cycle Water Consumption" include:

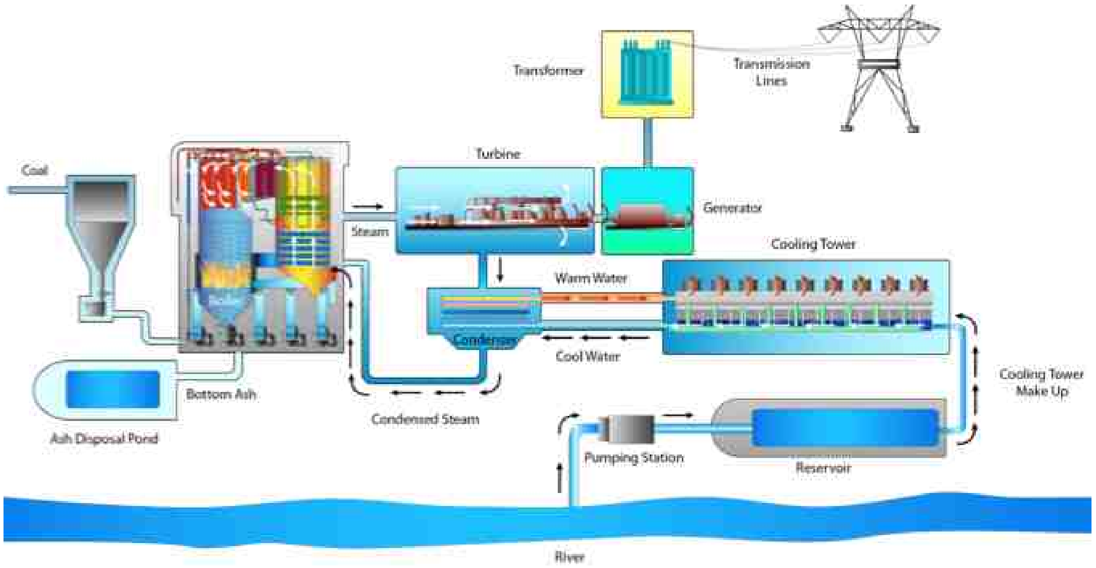
- Chemical dilution
- Ash transport
- Dust suppression
- Ponds
- Fire protection
- Cleaning and wash down
- Potable water: Human consumption, Sanitary waste disposal

Wet or dry FGD systems also use substantial make-up water. Obviously, wet FGD Systems use more water. FGD makeup water is required to saturate the incoming hot flue gas and as makeup to replace the blow down losses that are required to maintain process chemistry. Makeup is also required to replace the water that is lost with the gypsum that is generated as a byproduct from the FGD system. It has been estimated that wet systems use approximately 45 percent more water than a dry system [1].

Plant designs vary widely as do the techniques used in the disposal of the cooling water after it is passed through the condensers. Less water is required when cooling water is recycled through cooling towers or ponds, but a part of the cooling water is lost to evaporation and drift. Usually evaporation is between 3-5 percent of cooling water flow through the cooling tower.

When the withdrawn water for cooling is used only once before it is returned to a surface water body, a larger quantity of water is required. But evaporation, if any, is insignificant. Power plants consume large amounts of water for cooling and steam power generation and demand "best practices," when competing with interests such as water rights, protected species and fish resources exist. The major areas of water consumption by coal-fired power plants are cooling tower and steam cycle makeup as illustrated in Figure 4-3.

Figure 4-3: Illustration of a Typical Power Plant Water Withdrawal with Cooling Towers



Makeup Water (Circulating Water System)

Most coal-fired power plants have a closed loop circulating water system. The primary purpose of the circulating water system is to supply cooling water to the steam turbine surface condenser. Heat from the steam turbine condenser is removed by the circulating cooling water, which in turn is cooled in an evaporative cooling tower.

Cooling tower makeup water is required to offset evaporative losses, drift losses, and blow down losses. Blow down is required to maintain the circulating water chemistry within limits. The evaporation portion has historically not been recovered, but technologies are being pursued in an effort to recapture the evaporation.

Supercritical units do not use boiler blow down. But condensate polishing systems are required to treat the condensate pumped from the condenser hot well and remove dissolved and suspended solids to improve feedwater quality.

Typical water withdrawal and consumption for fossil plants are shown in Table 4-2 [2].

Table 4-2: Typical Water Withdrawal and Consumption for Fossil Plants (DOE 2006)

	Water (Steam Condensing) - Gal/MWh	
Cooling System	**Withdrawal**	**Consumption**
Oncethrough	20,000 - 50,000	~300
Cooling Tower	300 - 600	300 480
Cooling Pond	500 - 600	~480

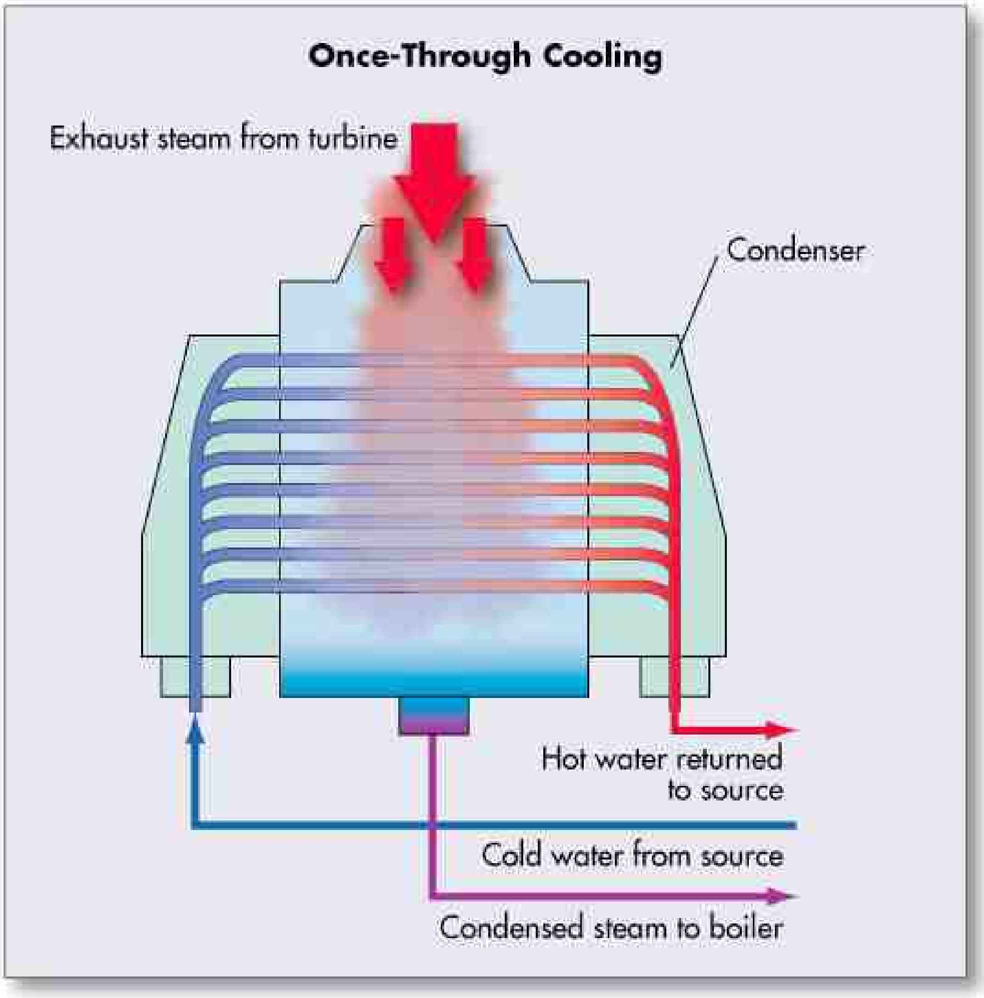
Cooling Water Systems

Water in a power plant is consumed, evaporated to the atmosphere or withdrawn with the majority returned to its source as a liquid with some level of contaminants and/or temperature change. Systems are generally once through or recirculating systems. With once-through cooling systems the water from source passes through the condenser and then is returned to the source. This system withdraws a significant amount of water, but consumes very little. To reduce the thermal impacts to a water source, cooling towers are used to minimize thermal impact prior to returning the water to its source. In a recirculating system, cooling water exits the condenser, goes through a fixed heat sink and is then returned to the condenser, so water withdrawal is low, but consumption is high relative to a once-through configuration. Typical heat sink options for recirculating systems are mechanical or natural draft cooling towers and cooling ponds. In cooling towers, the water is cooled by the air to near the wet-bulb temperature using the principle of evaporation. Water flows over a media called fill which serves to increase contact time with the air and maximize heat transfer. Mechanical draft cooling towers use fans to push or pull air through the towers, while natural draft cooling towers utilize large concrete chimneys facilitating a natural air current up the tower. While they require less power, natural draft towers are extremely large and generally only used at facilities with high cooling water requirements.

Make-up water to the cooling tower is required to replace the water that evaporates to the atmosphere and water lost to blow down to control cycle of concentration. Evaporation losses are typically the largest contributor to water consumption in a cooling tower system and can be estimated based on the cooling water flow rate and the cooling water temperature rise.

Conventional wet cooling by means of a cooling tower began to supplant once-through cooling. Once-through cooling takes water directly from a source and uses it to condense the steam and then returns the water to the original source at a higher temperature than withdrawn (Figure 4-4) [6].

Figure 4-4: Once-Through Cooling System Schematic

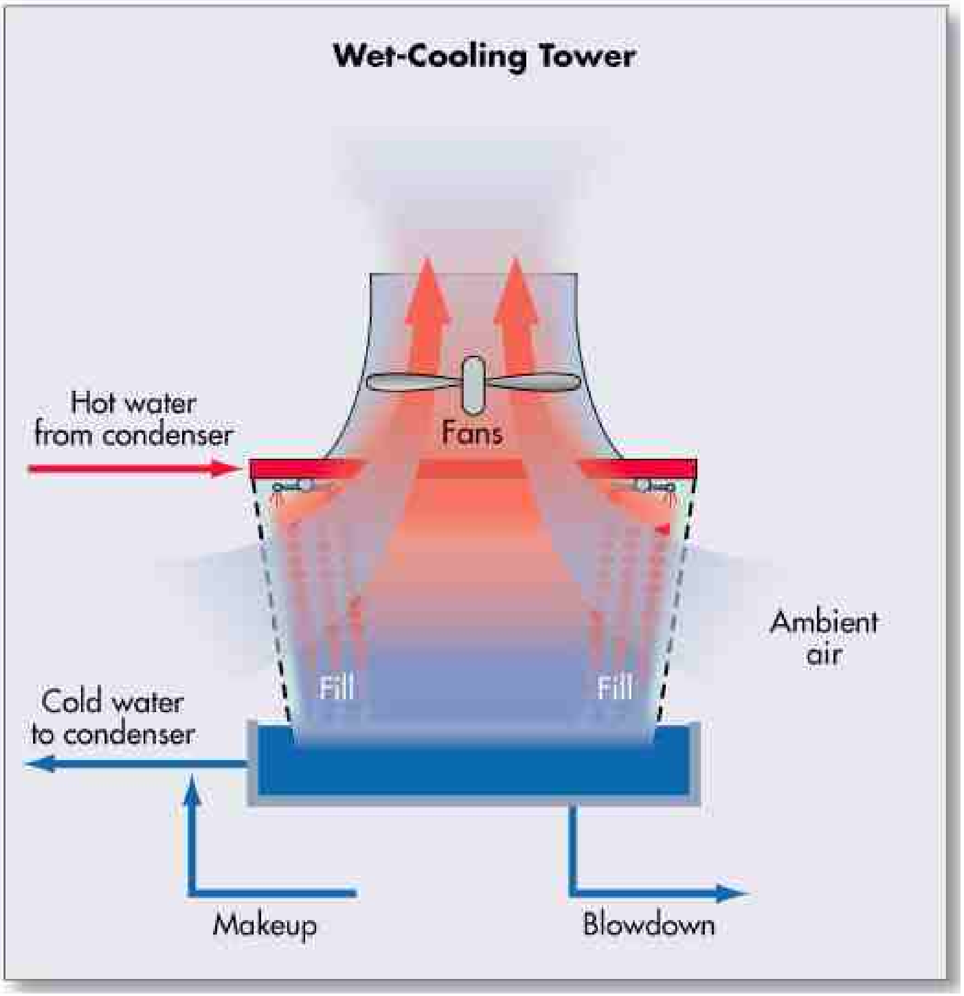


Wet Cooling Tower

With a wet cooling tower, the water leaving the condenser is pumped to the top of the cooling tower, where it flows downward through the "packing" or "fill," breaking the water into small droplets to maximize surface area exposed to the cooling airflow (Figure 4-5). Air is drawn through the tower by large fans and circulated water is cooled by a combination of evaporative and convective heat exchange. The cooled water is collected at the bottom of the tower and pumped back to the condenser to pick up heat in a continuous cycle, while the waste heat rises through the tower [6].

Wet cooling systems are either mechanical draft (as previously illustrated), or natural draft towers. Natural draft towers draw air through the tower by a natural chimney affect. Natural draft towers are costly to build, but have low operating and maintenance costs [6].

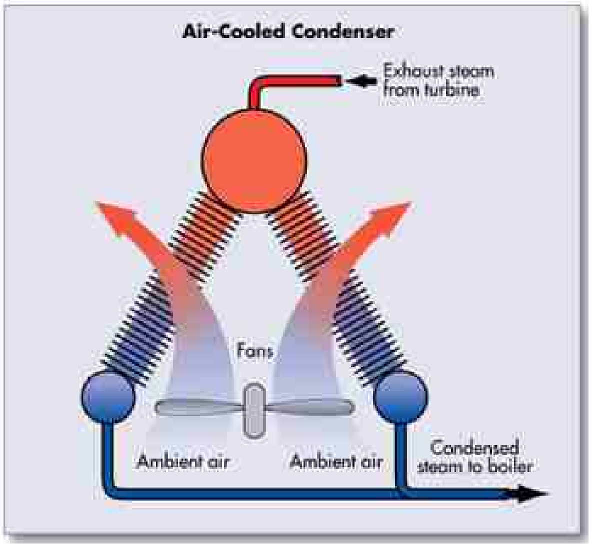
Figure 4-5: Wet Cooling Tower Schematic



Air Cooled Condenser (Dry Cooling)

Dry cooling (Figure 4-6) offers distinct advantages for reducing water consumption, and increasing the flexibility of power plant siting. However, the capital cost of dry cooling is considerably higher than wet cooling, and the dry cooling process typically results with a penalty on power plant performance during the hottest days of the year (Maulbetsch 2002; EPRI 2004). The capital and operating cost disadvantage of dry cooling can be offset by the elimination of water related costs in arid or water-constrained regions [6].

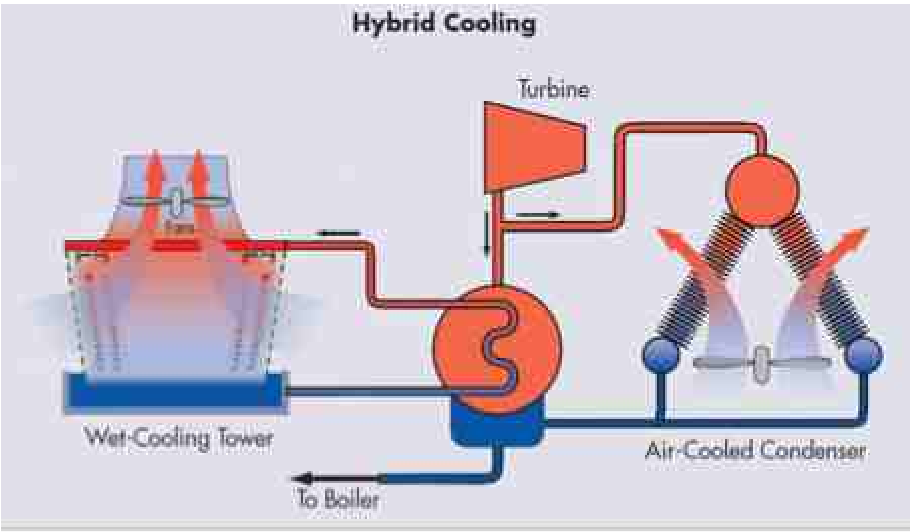
Figure 4-6: Dry Cooling Tower Schematic



Hybrid Cooling Systems

These systems combine an air-cooled condenser with a wet-cooling tower (Figure 4-7).

Figure 4-7: Hybrid Cooling Tower Schematic



The hybrid system helps to offset the efficiency disadvantage of all dry systems. By doing so, the wet system is used during the hotter seasons, when the dry systems are least efficient. Hybrid systems have been able to reduce the water that would be required by an all wet system by as much as 80 percent [6].

Dry and hybrid cooling are technologies that offer major opportunities for saving water (McGowin 2007). Dry cooling uses air instead of water to remove heat and cool condensers. Dry cooling dramatically reduces water consumption and increases the flexibility of power plant siting, but comes with higher capital costs than wet cooling and reduces power plant performance during hot-weather. Wind effects can also reduce the efficiency of dry cooling systems. Hybrid systems are essentially dry systems with just enough wet cooling to maintain needed generation efficiency during the hottest days of the year [5].

Much of the net-water consumption in a power plant is from evaporation and drift losses from cooling systems. Research published by the Electric Power Research Institute (EPRI) suggests that water use rates at plants with closed-cycle, wet cooling systems might not be sustainable in some locations as thermal discharges from once-through cooling face increasing regulatory scrutiny. Some plants already operate under water use restrictions or are being required to install water-conserving technologies. What's more, siting new capacity can be difficult due to water supply constraints. The net result is that cooling and water treatment technologies to reduce water consumption, the use of reclaimed water, and the reuse of internal water and even wastewater streams are gaining traction in the generation sector. For example, NV Energy's Walter M. Higgins Generating Station in southern Nevada, U.S. is a 530 MW combined cycle power plant that uses a six-story-high dry cooling system (Figure 4-8).

Figure 4-8: Energy's Walter M. Higgins Generating Station in Southern Nevada, USA 530-MW Combined Cycle Power Plant

Reference: POWER Magazine, Water Issues Challenges Power Generators, July 1, 2013, Similar to a car radiator, 40 fans (each 34 feet in diameter) condense the steam and cool plant equipment. The plant uses 0.053 m^3 (14 gallons) of water for each megawatt produced. By contrast, a conventionally cooled power plant of similar size might use as much as 2.46 m^3 (650 gallons) of water per megawatt [4].

4.3 WATER/MW (EFFICIENCY) AND SOLUTIONS FOR WATER CONSERVATION

Reducing water consumption at all types of steam power plants has been a worldwide concern for years, sparking a wide range of efforts to cut water use while meeting growing demand for electricity. Despite the industry challenges, there are many practical solutions available to manage water consumption challenges in India. Some of these include:

- Use permits and/or establish licensing requirements for power plants so that they incorporate local water needs
- Advanced steam cycle efficiency (turbine and boiler)
- Reduction of water consumption by recycling and re-use of ash water and other waste water
- Improved cooling technologies that reduce usage of fresh water. For example: dry cooling or wastewater cooling.
- Advanced condenser design
- Water treatment systems to reduce reliance on source water (i.e., using municipal waste water)
- Water purification and quality (to prevent losses from treatment)
- Protection against cooling water intake structures and prevention of small organisms damaging pumps, condenser tubing, and system pressure changes
- Dry ash disposal.

Lower but still significant additional water savings can be attained in coal plants by employing water conserving technologies to remove SO^2 from flue gas and mechanical systems that do not use water to capture and convey bottom ash (Electric Power Research Institute 2008). Also, the use of degraded water sources can help conserve fresh surface and groundwater sources. As population grows, the amount of wastewater effluent will grow, and likely the demand to use the effluent will increase [5].

Cooling Towers

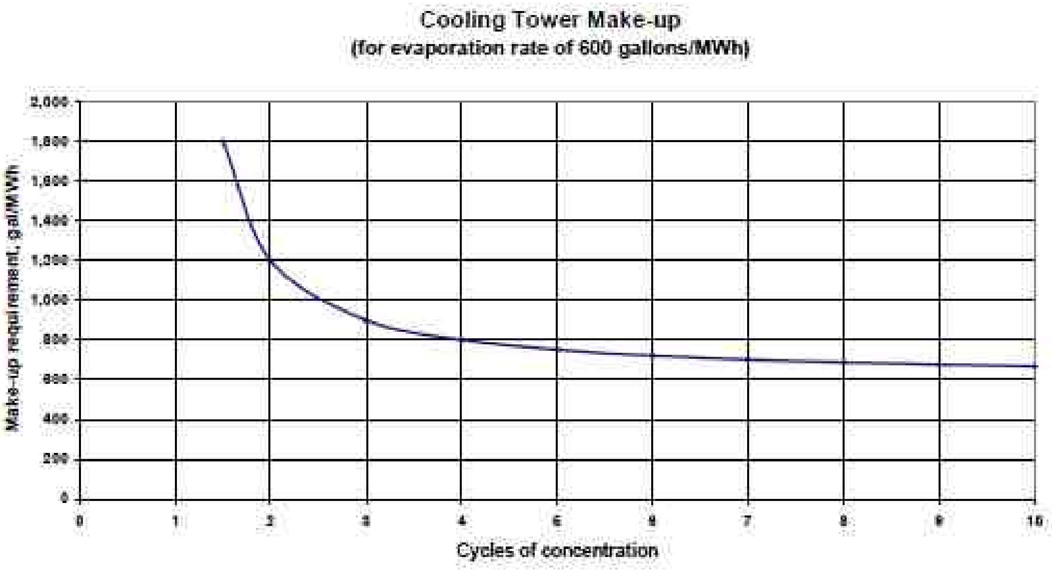
To reduce water usage in cooling towers, the cooling tower circulating water is cycled up the maximum amount of cycles allowed to maintain the water chemistry limits. This cycled up point is where additional cycling provides only a small makeup water savings, but greatly increases the risk of scaling and the need for water treatment chemicals. Considerations should be made when conserving water at the cooling tower. One of the most common ways is to evaluate the Cycles of Concentration (COC) [2].

COC Considerations:

1. Actual operating point dependent on source water
2. Make-up water saved vs. blowdown volume
3. Chemical treatment for scaling and corrosion
4. Materials of construction
5. Blowdown vs. FGD system make-up water (if installed)

The use of water from a lower quality source inevitably increases the total amount of water that must be taken into the plant. This results from the need to treat the water prior to use, either before it reaches the plant or inside the plant boundaries. All treatment processes generate a reject brine stream in addition to the product water; this typically increases the make-up requirements by 25-35 percent. For most uses, this is not a major issue. However, for cooling towers, the use of high salinity make-up, such as seawater or saline groundwater, can dramatically increase the make-up requirements. Cooling tower blowdown is required for all towers to maintain circulating water quality within acceptable limits. For good quality make-up, towers are typically run between 5-10 cycles of concentration (cycle of concentration is the ratio of the concentration of the blowdown to that of the make-up water). Higher cycles might be possible, but water savings reach a point of diminishing returns at cycles above 10. Seawater make-up, however, limits the cycles of concentration to 1.4 to 1.6. (Maulbetsch in press) As shown in Figure 4-9, the make-up requirements increase dramatically at these low cycles of concentration [3].

Figure 4-9: Makeup Water as a Function of Cycles of Concentration



[3] EPRI, Water Use for Electric Power Generation, Overview of Water Requirements

Water requirements for electric power generation vary with a number of factors, most significantly by the type of plant, fuel, and choice of the power plant cooling system. Other variables that influence the water demand are the local climate, water source, and environmental regulations. For example, Table 4-3 shows the estimated water requirements for plant cooling (in gallons/MWh) for different types of plants using different fuels and condenser cooling systems.

Closed cycle wet cooling for any of the steam-based, Rankine cycle plants – whether coal, gas, oil or nuclear – withdraws just a fraction (e.g. 2 percent) of the water required for once-through cooling, even though it might consume more water (EPRI 2004).

Table 4-3: Estimated Plant Cooling Water Withdrawal (Gal/MWh), Fossil Plants

	Cooling System Type			
Steam Plant Type	**Once- Through**	**Closed Cycle, Wet**	**Hybrid (wet/dry) [1]**	**Dry Cooling [2]**
Coal	25,000 45,000	550 - 800	275 - 725	0
Gas	20,000 35,000	500 - 700	250 - 650	0
Oil	20,000 35,000	500 - 700	250 - 650	0

(1) Low end for water conservation; high end for plume abatement

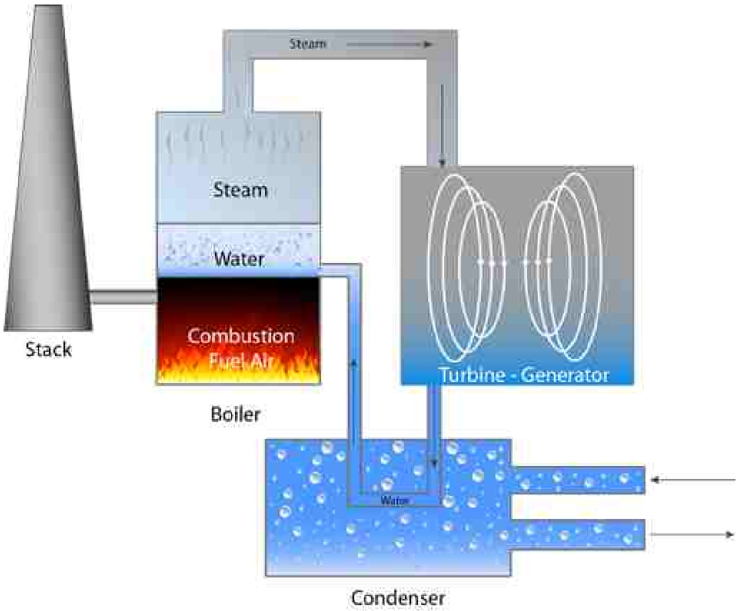
(2) Minimum amount used for cleaning finned tube surfaces (a few hundred thousand gallons annually).

Source: EPRI, Water Use for Electric Power Generation, Overview of Water Requirements

Water Re-Use Options

A supercritical plant's operating steam temperature, pressure, and exit gas temperature have major influences on power plant efficiency. However, condenser pressure is the most influential factor when looking at cycle efficiency. When considering Indian climatic conditions and limited water sources to meet the demand, both water and fuel conservation become very important. In an effort to conserve these natural resources, supercritical boiler and turbine design improvements are instrumental, but there are various opportunities for water conservation improvement when looking outside the boiler, and evaluating the power plant holistically.

Figure 4-10: Water and fuel Consumption Illustration



There are three things critical to the operation of a power plant. These include: water that gets turned into steam; fuel, and air that used in the boiler for producing the heat that creates steam for a turbine generator (Figure 4-10).

The ultimate aim is to reduce the amount of fresh water required at the front end or minimize the discharge of water all together. Different uses in the plant have different requirements for the purity of water. For example, boiler make-up water has a higher requirement than water for cooling. In general, if water is to be treated for reuse, it is preferable to treat it completely for the highest possible use and then let water cascade to lower use. Table 4-4 shows the use of water in terms of descending water quality [3].

Table 4-4: Water Quality by Use

Water Use	Water Quality Requirements
Boiler/reactor feedwater	Highest quality
Gas turbine inlet cooling	High quality
Hotel, housekeeping and potable water	Medium quality
Cooling tower	Medium quality
Ash sluicing	Low quality
Limestoneslurry for FGD	Low quality

Zero Liquid Discharge Systems

There is an increasing fraction of generating plants in the U.S. that are installing zero liquid discharge (ZLD) systems.

A ZLD system can be defined as all the equipment and systems that process and reclaim water that otherwise would be discharged. Typically, a ZLD system consists of evaporation ponds, surge ponds, a brine concentrator, and a crystallizer or occasionally, a dryer. Depending upon the specific site situation, ZLD systems may include only some of the system equipment or all of the process equipment components identified above [6].

Some ZLD systems can be very complex and include process equipment such as chemical treatments (physical-chemical), ion exchange softening, bio-reactors, sludge thickeners, solid bowl centrifuges, RO systems, and demineralizer systems. Often, a plant's ZLD system takes on a life of its own, continuously evolving into an ever increasingly complex organism. Water streams that are typically reclaimed through a ZLD system include the following [6]:

- Circulating cooling water blowdown
- Scrubber blowdown
- Boiler drum blowdown
- HRSG drum blowdown
- Demineralizer regeneration waste
- Miscellaneous low and medium waste water streams

Planning and designing a water balance that reclaims and reuses various water streams requires characterizing each individual stream. Often, water streams can be combined or fed to a separate system for reuse without processing it through a brine concentrator. This is the most efficient and cost-effective type of reclaim. For example, some plants use cooling water blow down as partial make-up to a scrubber system. This can be a relatively inexpensive solution for reclaiming water with relatively high dissolved solids if the scrubber process and materials are compatible. Also, if conditions permit, HRSG drums can be blown-down to circulating cooling water systems. Some process effluent water streams can have relatively low total dissolved solids, such as demineralizer rinse water. The low TDS demineralizer regeneration rinse water can be reclaimed to cooling water make-up. Alternatively, demineralizer regeneration discharge can be separated according to pH. High pH water is a perfect match for lime-soda ash reactivator influent while low pH water is compatible with lime-soda ash reactivator effluent. Water streams high in suspended solids can sometimes be most effectively reclaimed if a cleanable settling basin is installed upstream of the reclaim point. Storm water collection can be reclaimed to lime-soda ash reactivator influent or effluent depending upon its characteristics. Interestingly, some water reclaim pathways can have large negative impacts to the water balance. For example, if water streams with chloride are continually reclaimed or recycled, chloride concentration will continuously increase to very high levels. High chloride concentration increases the corrosion potential beyond the capability of heat-effected welds or stressed metal materials and components. High fluoride concentration can attack and damage titanium alloys. Ultimately, as TDS increases in a water stream, the only process that can reclaim the water is a brine concentrator (BC) and an accompanying crystallizer or evaporation pond. The circulating process solution of a BC typically has a TDS concentration of about 160,000 ppm. Knowing the TDS and flow rate of the BC feed water allows one to quickly estimate BC blowdown volume: solids in equal solids out [6].

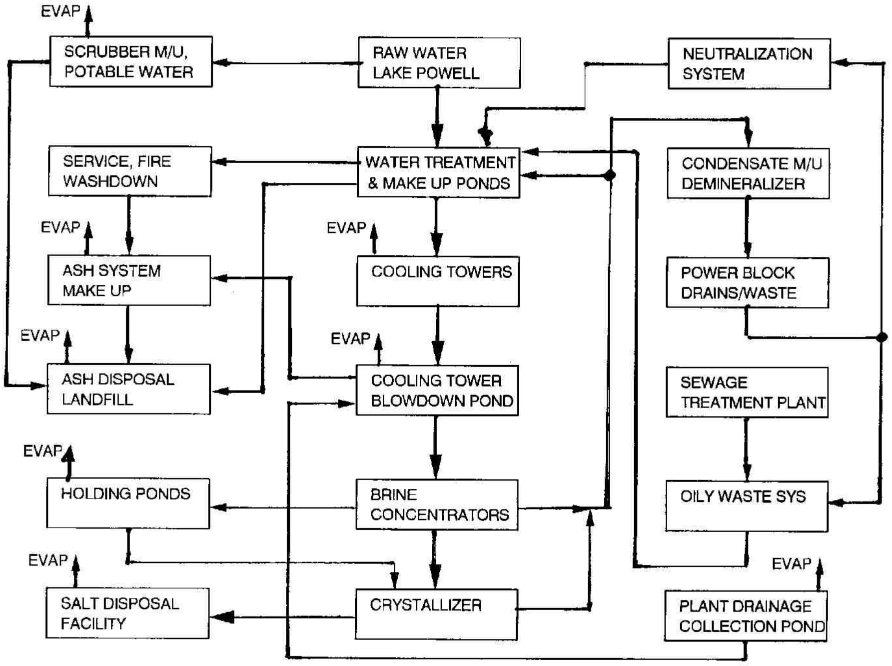
Case Studies

Salt River Project, Navajo Generating Station [6]

The Navajo Generating Station (NGS) is a three-unit, coal-fired generating station located in northern Arizona at the southern end of Lake Powell on the Colorado River. The station is composed of three 800 MW supercritical, once-through units. The first unit began producing electricity in 1974. Commercial operation of the other units began in 1975 and 1976. Raw water make-up is from Lake Powell. The station was originally conceived and operated as a ZLD facility. The NGS water treatment processes and water balance systems consist of raw water influent from Lake Powell, lime and soda ash water softeners, circulating cooling water systems, brine concentrators, a crystallizer, and evaporation ponds. The original design criteria for the station assumed an annual average wastewater flow of approximately 409 m^3/hr (1,800 gpm). Annual cooling tower blow down volume is about 1.9 million m^3 (500 million gallons) carrying about 20 million kg (44 million pounds) of solids (dry).

The general configuration of the NGS water treatment process is shown in Figure 4-11.

Figure 4-11: General Configuration of NGS Water Treatment Process



Considerations

A power plant's ZLD system design, construction and operations should be under the philosophy that device and system water discharges need to be minimized and any discharges need to be processed and/or reclaimed back to the system. Water processes need to be monitored, controlled, and maintained such that they always operate efficiently and within design specifications. Even short-term process excursions or device failures can result in major, long-term negative impacts to a plant's water balance.

The main functional objectives in designing and operating ZLD systems are to obtain maximum volume reduction and efficient solids handling. Reclaiming various types of process water can become increasingly challenging as the water becomes increasingly concentrated with dissolved solids. A brine concentrator (BC) and optional crystallizer are commonly the main pieces of equipment at the terminal end of a typical ZLD system.

Equipment considerations alone are not enough to design a ZLD system. Other factors such as materials, specialized treatment considerations, controls, operational process, maintenance and cost play an important role. These are discussed in detail in the March 2013 EPRI Water management conference paper that was presented by R.B. Peterson from Navajo Generating Station. The progressive concentration of dissolved solids through the NGS water balance is shown in the Table 4-5.

Table 4-5: NGS Water Balance Chemistry

Parameter	Raw Water	Service Water	Circulating Cooling Water	Brine Conc. BD	Brine Conc. Solids	Crystallizer Brine	Crystallizer Solids
Total Dissolved Solids (mg/L)	660	700	10,500	181,000		405,000	
Total Suspended Solids (mg/L)				112,000		178,000	
Boiling Point Rise (F)				2.7		16.4	
pH (pH Units)	8.0	8.8	7.2	6.5		6.76	
Conductivity (µS/cm)	700	750	11,000	190,000		503,000	
Na^+ (mg/L)	65	115	2,090	48,700	8,900	119,000	254,000
Ca^{+2} (mg/L)	66	20	380	320	251,000	<250	32,700
Mg^{+2} (mg/L)	22	14	280	3,210	760	8,660	10,800
K^+ (mg/L)	2.5	2.8	47	880	<1,500	18,100	3,200
SiO_2 (mg/L)	8.8	6.0	112	320	1,500	160	3,200
SO_4^{-2} (mg/L)	230	290	5,500	103,000	646,000	54,000	584,000
F^- (mg/L)	0.32	0.29	4.26	55	150	21	320
Cl^- (mg/L)	46	42	720	14,800	7,000	172,000	13,000

San Juan Generating Station

An example of the highly integrated water recycling scheme adopted at San Juan Station for water treatment is shown in Figure 4-12. The input streams of waste process water entering the process wastewater ponds are treated using a multipronged approach. The highest level of treatment is for boiler make-up water and is accomplished by distillation and reverse osmosis. The intermediate level is sent to the cooling tower and the lowest quality water is sent directly from the pond for limestone preparation for the process.

Figure 4-12: Simplified Water Balance San Juan Generating Station Water Treatment System

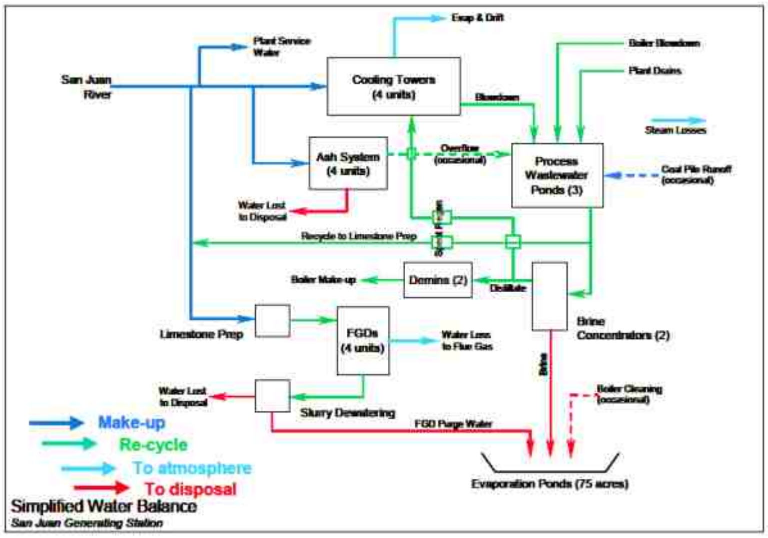
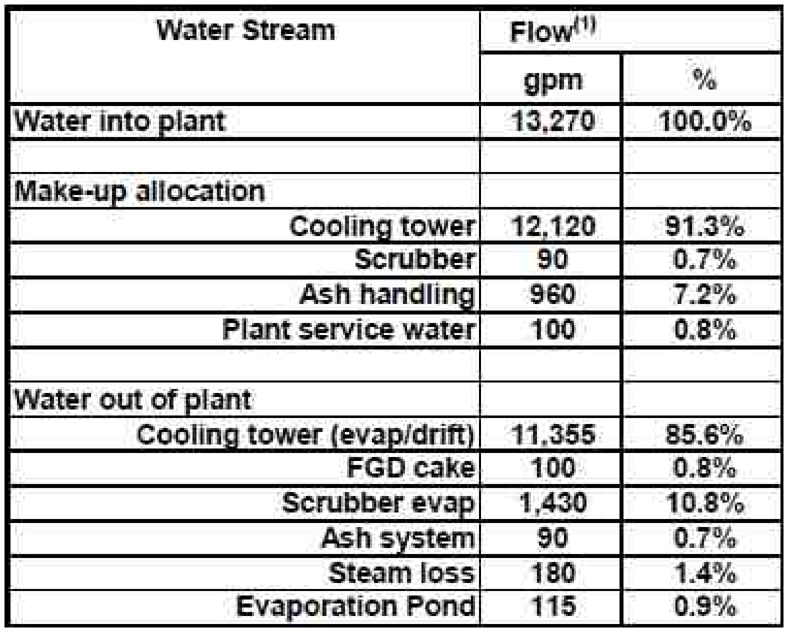


Table 4-6: Simplified Water Balance San Juan Generating Station Water Treatment System



Water Stream	Flow[1]	
	gpm	%
Water into plant	13,270	100.0%
Make-up allocation		
Cooling tower	12,120	91.3%
Scrubber	90	0.7%
Ash handling	960	7.2%
Plant service water	100	0.8%
Water out of plant		
Cooling tower (evap/drift)	11,355	85.6%
FGD cake	100	0.8%
Scrubber evap	1,430	10.8%
Ash system	90	0.7%
Steam loss	180	1.4%
Evaporation Pond	115	0.9%

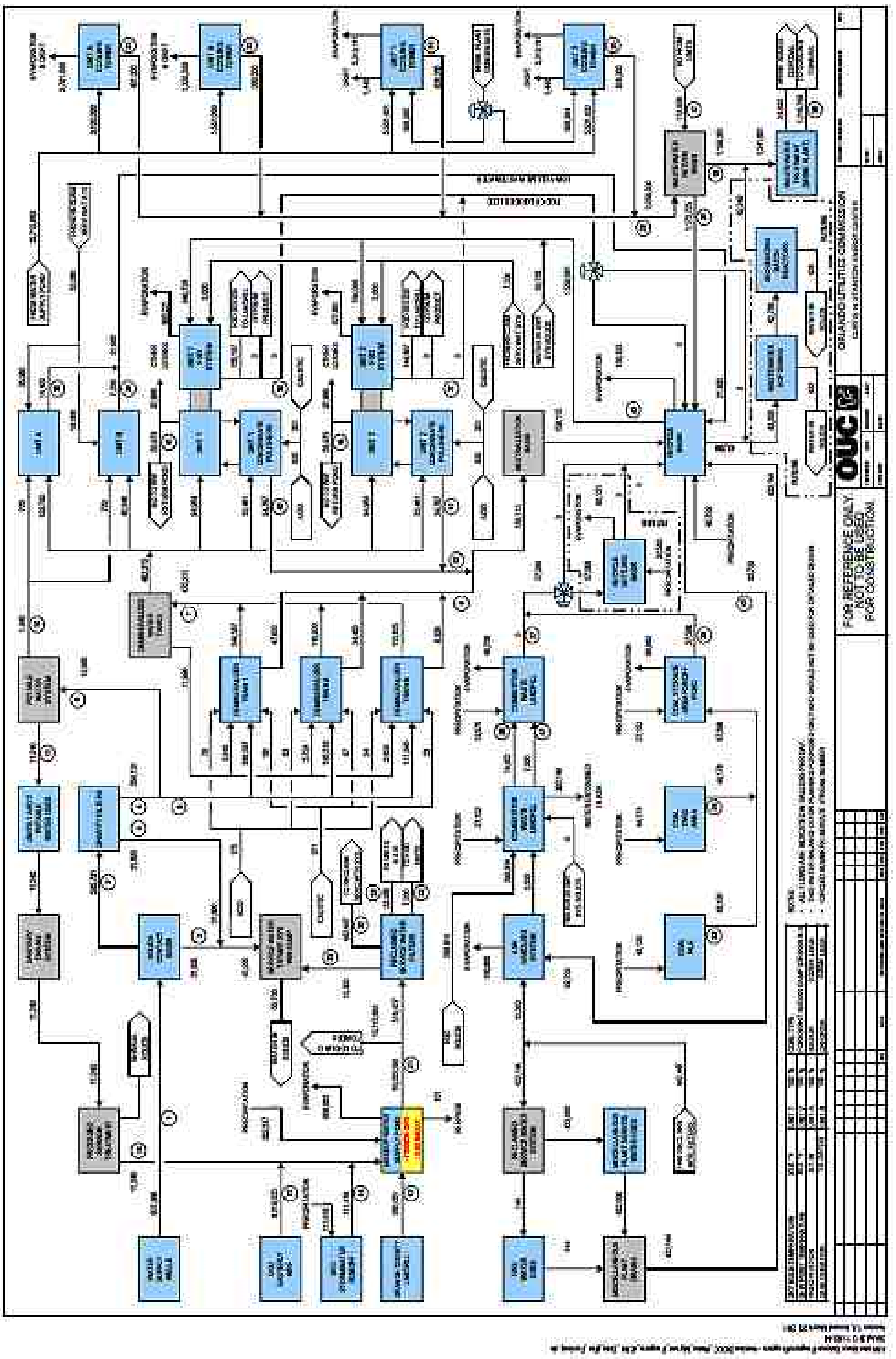
(1) @ capacity factor = 73.2% for 22,000 acre-feet/year

Orlando Utilities Commission (OUC), Stanton Energy Center

Stanton Energy Center operates Units 1 and 2 as a zero-water discharge facility. The Stanton Energy Center gets most of the water it needs from the Orange County Eastern Wastewater Treatment Facility. About 38,000m^3 (10 million gallons) of water is pumped to the site each day and eventually evaporated through the cooling towers. By re-using water that otherwise would end up in the River, OUC reduces the demand on the precious groundwater supply. All rain run-off on the site is diverted to holding ponds for re-use. Groundwater monitoring wells around each pond verify that none of this water leaks into the surficial Aquifer.

Similarly to the treatment process at San Juan, a multi-pronged treatment approach from the highest to lowest level treatment is used, depending on water demand for varying operations. The OUC zero discharge liquid plant water schematic is shown in Figure 4-13.

Figure 4-13: OUC Zero Discharge Liquid Plant Water Schematic [7]



Water Chemistry 5.0

5.0 Water Consumption

5.1 SUMMARY

Water chemistry impacts all equipment coming in contact with water or steam. A power generating facility cannot operate reliably without a quality water chemistry program. Water chemistry expectations and limits should be established utilizing the best available technology. Best practices outlined in the water chemistry balance section include action levels for the operator at specified limits to ensure quality water chemistry to protect the equipment. Oxygenated treatment is recommended as the best water chemistry program to provide reliable long-term operation of supercritical units.

Reliable operation of supercritical units requires specifying and installing accurate, precision chemical instrumentation and developing and implementing a quality maintenance program to retain its integrity. The ultimate objective is to ensure that the instrumentation provides the reliability necessary to make correct decisions for proper operation of the equipment.

Improper water chemistry is at the root of many woes in the operation of a steam power plant. Several topics such as steam generator (SG) tube failure, corrosion, corrosion fatigue, stress corrosion cracking, condenser tube leak and leak testing method, etc. are discussed in this section as they relate to water chemistry.

To ensure high standard of water quality requires setting up a structure that assigns responsibility for maintenance of the equipment such that it can be accomplished in a reliable manner for providing a routine maintenance program. The optimal structure of each organization is different, so this chapter provides the criteria that should be considered when assigning instrumentation maintenance responsibilities. A proper routine maintenance program is recommended.

SG tube failure is the leading cause of unavailability in power generating facilities. It is therefore imperative to be attentive to the root causes of tube failures. Four causes of tube failure will be addressed in this section. These causes are ID pitting, stress corrosion cracking, corrosion fatigue, and waterwall cracking. Utilizing the criteria described in the chemical cleaning best practices Section 5.8 ensures a clean steam generator minimizing the potential for OD waterwall circumferential cracking. Strict adherence to the water chemistry limits and action levels defined in Section 5.2 maximizes optimal boiler tube reliability. Utilizing a reheat drying procedure, as a best practice, every time the unit is shut down can significantly reduce the potential for pitting in the reheater tubes caused by moisture remaining when the unit is shutdown.

Many of the corrosion problems found in boilers/steam generators and turbine blades can be traced back to condenser leaks. Leaking condenser tubes allow cooling water to enter the condensate and feedwater supply. Cooling water is not purified to the extent of boiler/steam generator feedwater and contains many contaminants. Any contaminants introduced to the condensate and feedwater supply can become active components of numerous corrosion mechanisms. Condenser leaks are typically the greatest source of contaminants to condensate and feedwater.

Mechanical and corrosion mechanisms that can result in condenser tube failure are addressed. Best practices addressed to help ensure condenser reliability include Eddy Current Testing (ECT) of condensers to help determine the remaining life of the tubes, trend tube degradation, and/or to locate tubes which may fail before the next major planned outage so they can be plugged. Plugging procedures are also addressed to ensure reliable repairs of leaking tubes. Considerations to address when making end-of-life decisions are presented.

There are several contaminants that can result in turbine blade deposits or corrosion. These include iron, sodium, silica, chloride, and sulfate. The contaminants cause performance degradation or turbine blade failure. Best practices recommend monitoring iron with Millipore samples and establishes that the coloration of the sample must be “snow white” to meet the required standards. The parameters that are required to control iron are also discussed. The phase transition zone (PTZ) is presented as an especially susceptible area for deposition. The expected appearance is presented to enable quality inspection and sampling. Another part of maintaining a reliable well performing turbine is a well-structured, documented turbine sampling process. Guidelines for this are also presented.

Operating supercritical plants with high reliability and high efficiency requires structuring the chemical functions of the organization to utilize best practices in the laboratory and chemical analysis. This requires developing a structure that optimally allocates all of the necessary functions. These include effective monitoring, sampling, analysis, direction and goals, R&D, and oversight. A structure that divides these tasks between General Chemistry Standards and control department (Service Corp), Central Lab, and Plant lab is presented in such a way that optimally utilizes the skills resident in each entity.

Timely and effective chemical cleaning, i.e., maintaining water chemistry in a supercritical unit before heat transfer can be the life saver of a steam generator. However, accurately detecting the scale on the tube ID before it significantly impacts heat transfer and tube life can be very challenging. This section provides guidance on utilizing best available technology to measure oxide deposits and setting up criteria to enable reliable steam generator operation. Historic methods of determining tube deposits includes removing a tube sample from the steam generator at a location most likely to have the heaviest deposit during major outages and scraping the tube sample, or bead blasting it. This was an effective method as long as the only deposits to be removed were the iron transported from the condensate and feedwater systems. As less corrosive water treatments such as oxygenated treatment, became known it became practical to extend the time between cleanings, duplex in situ oxide layers formed making the old detection methods ineffective. Supercritical units operated on oxygenated treatment (OT) form very tenacious deposits which contain three distinct layers. These layers are defined as spinel, hematite and magnetite. The section presents the Scanning Electron Microscope (SEM) is the best method for accurate tube sample analysis and condition assessment. After SEM analysis, thermal conductivity can be determined by the porosity of the deposits of both the structural material (the tube) and of the medium which fills the pores can be determined.

This chapter provides building blocks for the successful chemical balance necessary for world-class operation of a power generating facility.

5.2 WATER CHEMISTRY BALANCE

Feedwater chemistry is critical to the overall reliability of supercritical generating facilities. Safe, reliable operation of large power generating plants depends upon the establishment of chemical conditions throughout the steam-water circuit that minimize the corrosion of construction materials and suppress the formation of deposits. The chosen chemical treatments and instrumentation depend upon the details of plant type, circuit design, metallurgy, physical parameters (temperatures, pressures, heat fluxes, etc.) and intended operational mode of the plant (base, medium or peak load operation). In all cases it is essential to be able to measure the key chemical parameters and to take action on the basis of these measurements to ensure that chemical targets are achieved.

Supercritical plants are subject to several corrosion mechanisms in the water/steam cycle. These include:

- Flow-accelerated corrosion (FAC), due to the accelerated dissolution of the protective oxide (magnetite) on the surface of carbon steel components caused by flow.
- Corrosion fatigue (CF), due to repetitive applied stress causing damage to the internal protective oxide layer (magnetite).
- Pitting corrosion due to inadequate shutdown procedures throughout the cycle.
- Stress corrosion cracking (SCC) of sensitive steel components in the superheater, reheater and steam turbine due to the presence of impurities, such as sodium hydroxide and chloride.

Corrosion must be prevented through treatment of the water. Three modes of treatment are available for accomplishing this task. These are defined as AVT (R) – All Volatile Treatment (Reducing), AVT (O) – All Volatile Treatment (oxidizing), and OT -- Oxygenated Treatment. This section provides limits and some best practices to help ensure safe reliable operation. Additional information can be obtained on these treatments from the International Association for the Properties of Water and Steam (IAPWS) [2]. Experience has shown that OT is the preferred water treatment for supercritical units, so the following discussion will address some areas of concern when utilizing this treatment mode.

Cation Conductivity

To provide reliable long life for equipment, feedwater cation conductivity should be maintained at the lowest feasible level. Many highly respected authorities set the limit at 0.15 µmho. However, a well maintained condensate polishing unit can provide a cation conductivity of 0.06 µmho. Therefore it is reasonable to establish that anytime the feedwater cation conductivity exceeds 0.1 µmho, an abnormal condition exists and the cause should be investigated. A supercritical unit requires a large investment of capital and the loss of its generation results in a significant loss of revenue. To maximize the reliable life of this equipment, a best practice is to set the abnormal cation conductivity limits at 0.1 µmho.

Dissolved Oxygen

Dissolved oxygen must be maintained between 30 and 150 ppb in both the condensate and feedwater systems. Air or oxygen injection may be required to accomplish this and deaerator vents should normally be closed, although cycling of the vents may be required to avoid exceeding 150 ppb in the feedwater cycle. Deviation from these limits can be tolerated for several days and credible sources have suggested that deviation from these limits could be tolerated for up to two weeks, since it takes a significant period of time to convert the passive layer back to magnetite.

pH

There are several schools of thought on the pH required for operating on OT. IAPWS recommends a range of 8.0-9.8 as shown in Table 5-2 feedwater chemistry limits. This range would allow operation of the unit with a pH as low as 8.0 potentially requiring less ammonia and extending condensate polisher life. However, a caveat to this recommendation is given if two-phase FAC is experienced, suggesting that it may be necessary to raise pH to the upper limit of 9.8 to stem this phenomenon. The IAPWS Technical Guidance Document "Volatile Treatments for the steam-water circuits of fossil and combined cycle/HRSG power plants" provides insight and guidance on this subject as follows:

Although there should not be any two-phase flow in a properly designed plant, two-phase FAC is a common failure mechanism as well as a source of increased corrosion products in parts of the feedwater of conventional fossil plants. Basically, the only way to deal chemically with the two-phase regions is to ensure that the pH of the liquid phase is as high as the particular unit/materials/chemistry will allow. Those plants of most concern are where the feedwater pH is at 9.0 or lower. Obviously drain lines should be designed to drain off water (single-phase) from feedwater heaters. For fossil plants, a number of locations are important: drain or emergency drain lines downstream of control valves, and heater and deaerator shells and internals in the vicinity of cascading drain fluid entries [2]. For units operating with feedwater at pH levels below 9.0, especially once-through or supercritical units on OT operating in the pH range 8.0–9.0 with the vents on the heaters and DA open, the drain lines and other areas are particularly susceptible.

With total iron levels in the feedwater drain lines much greater than ~10 µg/kg, it may be necessary to increase the pH up to 9.8 (IAPWS).

Other experts in the field have recommended maintaining a pH of 9.2-9.6 to minimize two-phase FAC. A large U.S. utility has done extensive testing to validate that maintaining a pH of 8.8-9.0 has been effective at minimizing two-phase FAC. As can be concluded from the various recommendations, two-phase FAC requires additional research; however, due to the many FAC issues that have been experienced, the recommendation of this section is to operate supercritical units on OT with a pH of 8.8-9.0.

Inspection

Inspections of accessible vessels and piping should be conducted at planned intervals. During these inspections, all internal surfaces should be red (hematite). The presence of any black surface (magnetite) reveals insufficient oxygen is present.

In vessels where significant turbulence and two-phase FAC could exist such as deaerators, it may be difficult to maintain this condition, however, not exhibiting the red appearance suggests corrosion is likely and wall thickness should be monitored. When conditions prevent proper protection, and two-phase FAC cannot be prevented, either the metal should be replaced with material containing a nominal amount of chrome or the surface should be pad-welded with rod containing a nominal amount of chromium.

Heater Drains

It is very important to maintain an oxygen rich chemistry in the heater drains. Two schools of thought exist on whether to operate with the vents open or closed. Some highly respected organizations insist that the heater vents must be closed to ensure that the heater drain chemistry remains oxygenated; however some utilities have extensively tested the heater drain chemistry with the heater vents open and have assured themselves that sufficient oxygen is present to protect the piping and to prevent single phase FAC.

Normal Water Chemistry Values and Action Levels

A Best Practice is to establish operating procedures with action levels for the operator to implement when water chemistry deviates from the expected values. Although establishing parameters for controlling water chemistry provides instruction required for operation, it does not provide the guidance necessary for operating as problems develop. The first step to preventing these failure mechanisms involves developing a set of Action and Shutdown Levels, which will require the plant operator and/or chemist to take some prescribed avoidance actions. A large U.S. utility has initiated action levels that the operator and chemist can adhere to as problems are detected. The limits utilized deviate slightly from the guidance provided by The International Association for the Properties of Water and Steam; however, they provide a basis on which to build a program. Although these tables provide one utility's approach to building an action level program, the next step involves customizing these tables to the specific unit conditions, materials and possible damage mechanisms following this roadmap approach. The following tables and associated action levels provide parameters that have been used to control supercritical units operating with oxygenated treatment. It has accomplished this by initiating three action levels and ultimately shutdown of the unit.

The steps are as follows:

- Action level 1 – Parameter should be returned to normal values within 76 hours. If parameter does not return to normal in 76 hours, parameter moves to action level 2.
- Action level 2 – Parameter should be returned to normal within 24 hours. If parameter does not return to normal in 24 hours, parameter moves to action level 3.
- Action level 3 – Parameter should be returned to normal values within 4 hours. If parameter does not return to normal in 4 hours, a controlled shutdown of the unit shall be initiated.

Tables 5-1, 5-2, and 5-3 values and action levels are applicable to fossil plants with once-through supercritical units operating on oxygenated treatment with all-ferrous feedwater systems, non-copper tube condensers, with a condensate polisher, and not cooled by seawater or brackish water.

Table 5-1: Condensate Chemistry Limits

Parameter	IAPWS Normal values	Utility Normal Value	Utility Abnormal	Action Level 1	Action Level 2	Action Level 3	Immediate Shutdown of Unit
Cation Conductivity (μmho)	< 0.3	< 0.2	> 0.2	N/A	N/A	N/A	N/A
Sodium (ppb)	< 3.0	< 3.0	> 3.0	N/A	N/A	N/A	N/A
Dissolved Oxygen (ppb)	< 10	< 20	> 20	N/A	N/A	N/A	N/A
Silica (ppb)	N/A	< 20	> 20	N/A	N/A	N/A	N/A
Condensate Polisher Outlet							
Cation Conductivity (μmho)	< 0.15	< 0.1	0.1- 0.2	> 0.2	> 0.3	> 0.65	N/A
Sodium (ppb)	N/A	< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0
Silica (ppb)	N/A	< 5.0	> 10	N/A	N/A	N/A	N/A
Sulfate (ppb)	N/A	< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0
Chloride (ppb)	N/A	< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0

Table 5-2: Feedwater Chemistry Limits

Parameter	IAPWS Normal values	Utility Normal Value	Utility Abnormal	Action Level 1	Action Level 2	Action Level 3	Immediate Shutdown of Unit
Cation Conductivity (μmho)	< 0.15	< 0.1	0.1 0.2	> 0.2	> 0.3	> 0.65	> 2.0 (5min) > 5.0 (2min)
pH	8.0 9.8	8.8 9.0	8.1 8.8	N/A	< 8.0	< 7.5	< 7.0
Dissolved Oxygen (ppb)	30 150	30 150	< 30	N/A	N/A	N/A	N/A
Sodium (ppb)		< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0
Chloride (ppb)		< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0
Iron (ppb)		< 3.0	> 3.0	N/A	N/A	N/A	N/A
Copper (ppb)		< 3.0	> 3.0	N/A	N/A	N/A	N/A
Suspended Solids (ppb)		< 10	10 35	> 35	> 50	> 100	> 150
Silica (ppb)		< 10	10 20	> 20	> 30	> 40	> 50
Sulfate (ppb		< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0

Table 5-3: Main Steam Water Chemistry Limits

Parameter	IAPWS Normal values	Utility Normal Value	Utility Abnormal	Action Level 1	Action Level 2	Action Level 3	Immediate Shutdown of Unit
Cation Conductivity (μmho)	< 0.15	< 0.1	0.1 0.2	> 0.2	> 0.3	> 0.65	> 2.0 (5min) > 5.0 (2min)
Sodium (ppb)	< 2.0	< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0
Chloride (ppb)		< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0
Iron (ppb)		< 3.0	> 3.0	N/A	N/A	N/A	N/A
Copper (ppb)		< 3.0	> 3.0	N/A	N/A	N/A	N/A
Silica (ppb)		< 10	10 20	> 20	> 30	> 40	> 50
Sulfate (ppb		< 3.0	N/A	> 3.0	> 6.0	> 12.0	> 24.0

Two parameters continuously monitored by operations are pH and cation conductivity. It is very important for the operator to understand the expectations if either of these parameters exceed trip values. The actions that should be taken are restated below.

- Any time the economizer inlet pH of a supercritical unit drops below 7.0 the unit should be tripped immediately.

- Any time the economizer inlet and main steam cation conductivity of a supercritical unit is above 2 umhos for 5 minutes the unit should be tripped immediately.*
- Any time the economizer inlet and main steam cation conductivity of a supercritical unit is above 5 umhos for 2 minutes the unit should be tripped immediately.*

* Note: To compensate for instrumentation reliability issues, a '2 out of 2' philosophy requires both economizer inlet and main steam cation conductivity to exhibit the high cation conductivity before tripping the unit.

5.3 CHEMICAL INSTRUMENTATION MAINTENANCE

The organization that should perform the maintenance within a plant is best determined by examining where the expertise exists. The frequency and scope of the maintenance are also critical, since the reliability and efficiency of the plant can be significantly impacted by errant instrumentation. Since the operator and chemist make decisions about the operation of the unit based on this instrumentation, its credibility is paramount.

Organizational Maintenance Structure

Potential structure include: Chemical operations group, instrumentation and control group (I&C), instrumentation maintenance contractor, and OEM. U.S. companies have employed all of these options. The option chosen reflects the skills and structure of the organization, the expertise available in the area, and the brands of instrumentation purchased.

Utilizing the chemical operations group provides a cross-functional understanding of the tools used to monitor the cycle. The chemist understands what types of failures can occur with the equipment and knows how the instrumentation should perform. When the instrumentation output is not as expected, he/she has the ability to determine if the problem is the cycle or errant instrumentation. With this option, maintenance of the equipment is handed-off to the Instrumentation and Controls (I&C) group when electronic expertise is needed.

Creating specialty groups is another way that responsibilities can be allocated. This option delegates responsibility for instrumentation maintenance to the I&C group and limits the chemist's responsibility to monitoring the instrumentation outputs and maintaining cycle chemistry. This enables each group to focus on their area of specialty and expertise. However, it also typically slows maintenance and limits the chemist's understanding of the equipment.

Delegating instrumentation maintenance to an outside contractor is another option for maintaining the instrumentation. This limits understanding of the instrumentation to off-site personnel only but it reduces the full time on-site staff required, as well as the necessary training. However, it eliminates on-site expertise and will likely slow repair time. Having one contractor that does all instrumentation maintenance enables building a relationship and limits the number of different outside contractors required for this purpose.

Utilizing the OEM-supplied instrumentation provides the highest level of expertise. If all instrumentation is sourced from the same manufacturer, this can be an effective means of maintenance. However, if several different OEMs are required, it can result in the need for many different contractors to complete the maintenance. OEMs typically do not reside locally, so transportation costs for multiple contractors can escalate rapidly.

Instrumentation Maintenance

The primary objective is to develop a program that ensures reliable operation of the instrumentation. To accomplish this, instrumentation must be specified that provides accurate output with the precision required to meet the water quality specifications. Instrumentation maintenance varies with manufacturer and technology, so the OEM manuals should be consulted to determine the recommended maintenance. An example of the maintenance process conducted by U.S. utilities is provided in Table 5-4.

Table 5-4: Monthly Instrumentation Maintenance

Analyzer	Monthly Maintenance	Notes
pH	• Check the reference agent supply and refill if necessary (Reservoir 1/2 full or less). • Perform a sample cleaning. • Perform a calibration.	• Depletion rate of reference agent. • May vary for each instrument. • If necessary, place order for additional reagents.
Cation Conductivity	• Verify cation column is not exhausted and replace if necessary. • Perform a sample cell cleaning. • Perform a calibration.	• If necessary, place order for additional cation columns/resin.
Specific Conductivity	• Perform a sample cell cleaning. • Perform a calibration.	
Sodium analyzer	• Replace all reagent and fill solutions. • Perform a sample cell cleaning. • Perform a calibration.	• If necessary, place order for additional reagents.
Silica	• Check the reference agent supply and refill if necessary (Resevoir 1/2 full or less). • Perform a sample cleaning. • Perform a calibration.	• If necessary, place order for additional reference agents.
Dissolved Oxygen	**(Only Perform Quarterly)** • Replace electrolyte fill solution, membrane assembly and O-ring. • Perform a calibration.	• If necessary, place order for additional electrolyte solution and spare parts.

5.4 PREVENTING BOILER TUBE LEAKAGE

Steam generator tube failure is the leading cause of unavailability in power generating facilities. It is therefore imperative to be attentive to the causes of tube failure. Four causes of tube failure will be addressed in this paper. Those causes are Pitting, Stress corrosion cracking, Corrosion fatigue, and Waterwall cracking. Section 5.8 provides a section dedicated to tube leak prevention strategies.

Supercritical Waterwall Cracking

Damage generally forms as regular, parallel cracking, typically oriented circumferentially on the fireside OD of the tube. Thermal or stress cycles with heavy deposits leads to supercritical waterwall cracking.

There are several root causes of supercritical waterwall cracking. One commonly understood root cause is the buildup of excessive corrosion product deposits on steam generator tube surfaces. These corrosion products are transported from the condensate/feedwater system and deposited within the steam generator.

The main effect of this deposited layer of corrosion products is to increase tube metal temperature. The temperature of the tube wall increases as a result of the insulation of the tube metal from the cooling effect from the boiler water flow. Also, flow irregularities caused by the deposits can lead to tube-to-tube flow variations. This can lead to both decreased heat transfer and reduced boiler water flow through a tube. Lastly, due to the insulating effects of the deposits, heat transfer through the tube will be decreased. As a result, to achieve the desired fluid temperature on the inside of the tube, the fireside temperature may require further increase, exacerbating tube metal temperatures. The resulting tube metal temperatures can exceed material design limits and cause thermal fatigue of tube material, resulting in tube failure.

To control supercritical waterwall cracking due to excessive deposition of corrosion products, the amount of corrosion products present in the steam generator must be minimized. This is done by optimizing the condensate/feedwater system chemical treatment program, as discussed previously, to decrease the amount of corrosion product available to be transported into the steam generator. When deposits become excessive, supercritical units are chemically cleaned to remove deposits from boiler tube surfaces. The less corrosion products that are transported to the steam generator; the more successfully corrosion of the condensate/feedwater system can be minimized. In turn, this leads to less chemical cleaning of the steam generator.

Best Practice

The chemical cleaning procedure in Section 5.8 is recommended to ensure a clean steam generator and avoid waterwall circumferential cracking.

Internal Pitting

Internal pitting is caused by sulfate and/or oxygen plus water and it happens when the unit is shutdown. Pitting is a form of corrosion that occurs only while the unit is offline. It is typically caused by oxygen-saturated stagnant water. It can also be caused by salt contaminants (chlorides and sulfates) that are deposited on boiler tubes coming in contact with moisture during unit shutdown and layup.

Oxygen pitting is initiated by the presence of dissolved oxygen in stagnant water. Left unchecked, stagnant water and dissolved oxygen will lead to damage of the protective magnetite layer found on boiler tube surfaces. Once pitting is initiated, pit growth will continue during each unprotected shutdown of a unit. Pitting can then act as the initiating steps for other damage mechanisms including corrosion fatigue and stress corrosion cracking.

Another form of pitting is initiated by the deposition of contaminant salts onto boiler tube surfaces. This occurs in sections of the boiler/steam generator where during normal operation only dry steam flow occurs, such as reheaters. Certain conditions are required for corrosion to occur and one of these is the presence of water. During normal operations, contaminant salt deposited on a reheater boiler tube surface is unable to initiate pitting as no liquid water is present.

However, during unit shutdowns, as the unit cools, steam condenses to liquid water. This water will dissolve the contaminant salts present, forming acidic species. At the deposited salts location on the boiler tube surface, these acidic species will be concentrated, leading to a greatly reduced local pH. This low local pH will strip the protective magnetite from a tube surface and initiate the formation of a pit at the unprotected metal surface. When the unit is restarted and the water is evaporated, the pitting corrosion will be stopped. However, the contaminant salts remain in the pit and pit corrosion and growth will resume the next time water is present.

To control pitting corrosion, proper shutdown and layup procedures of a unit must be utilized every time a unit is shutdown. A dry layup involves completely drying the boiler to remove all water. A wet layup is used if no oxygen is present in boiler water and a nitrogen blanket can be applied to the unit to prevent the ingress of oxygen. Or, if oxygen is already present, circulation of the boiler water can be achieved to eliminate stagnant conditions.

Figure 5-1: Pitting and Stress Corrosion Cracking

Best Practice

To prevent pitting in units with reheaters, *a reheat drying procedure must be utilized every time the unit is shutdown.* Significant pitting in Reheat superheaters has been experienced due to moisture remaining in the reheater when unit was shutdown.

Stress Corrosion Cracking

Stress Corrosion Cracking (SCC) is a defined as cracking of metal produced by the combined action of corrosion and stress. It is caused by chlorides plus water. It is initiated on shutdown and propagated during operation. Essentially, SCC is initiated by the creation of pits (as described in the pitting section) and over time the combination of the environment and stresses will grow the pit until it forms a crack. Once a crack is formed it is only a matter of time until the material fails. The risk for SCC can be reduced by eliminating the water chemistry related initiating steps of pit creation. As such, it is extremely important to perform layup and reheat drying procedures to control pitting corrosion. The best practice is to control boiler water pH and trip the unit when it drops below 7.0.

Corrosion Fatigue

Corrosion fatigue occurs with the combined action of cycle loading and a corrosive environment. Corrosion fatigue is caused by the synergistic effects of stress and the environment. This leads to a breakdown of the protective magnetite layer on a tube surface by both mechanical stress and an aggressive chemical environment. Stresses due to cyclic loading (startup/shutdown of unit) create pits at unprotected boiler tube surfaces. Further cyclic stresses cause pits to align in a crack, eventually leading to failure. Proper boiler water chemistry can help reduce the risk for corrosion fatigue. During startup, cyclic stresses are at their highest. Low pH excursions or high levels of dissolved oxygen combined with high cyclic stress have been proven to be particularly damaging to the protective magnetite layer. As such, it is extremely important to maintain proper water chemistry during unit startup, and that OEM heat-up and cool-down rates are not exceeded. Best practices include controlling dissolved oxygen, especially on startup and pegging the deaerator as soon as possible on startup.

Figure 5-2 : Corrosion Fatigue Boiler Tube Failures

Figure 5-3: Corrosion Fatigue Cutaway

Figure 5-4: Corrosion Fatigue Tube Failure

Best Practices

- Any time the economizer inlet pH of a supercritical unit drops below 7.0, the unit must be tripped immediately.
- Any time the economizer inlet and main steam cation conductivity of a supercritical unit is above 2 µmhos for five minutes the unit must be tripped immediately.
- Any time the economizer inlet and main steam cation conductivity of a supercritical unit is above 5 µmhos for two minutes the unit must be tripped immediately.
- For units with reheaters, reheat drying procedures must be implemented following every unit shutdown.

Maintaining optimal boiler tube reliability, requires strict adherence to the water chemistry limits and action levels defined in Section 5.2 – Water Chemistry.

5.5 PREVENTING CONDENSER LEAKAGE

Quality water chemistry is the primary and first building block for reliable power generating facility operation. Experts agree that the condenser is the greatest source of contamination. Improper maintenance of the condenser will result in unnecessary contamination of the cycle resulting in other major equipment failures (i.e. steam generator tube leaks, turbine blade failure, etc.). An effective program of inspection and repair must be developed to ensure reliable condenser operation. This section provides direction for dealing with this problem. Operating a reliable condenser in a power generating facility requires a multifaceted approach. The building blocks to accomplish this include an effective leak detection program, dependable predictive maintenance tools, and a reliable repair and replacement program. The leak detection program is outlined in (Section 7.4 - Condenser Leak Detection). The best practices outlined below will discuss proven predictive maintenance tools and repair processes that will enable reliable condenser operation.

Many of the corrosion problems found in boilers/steam generators and turbine blades can be traced back to condenser leaks. Leaking condenser tubes allow cooling water to enter the condensate and feedwater supply. Cooling water is not purified to the extent of boiler/steam generator feedwater and contains many contaminants. Any contaminants introduced to the condensate and feedwater supply can become active components of numerous corrosion mechanisms. Condenser leaks are typically the greatest source of contaminants to condensate and feedwater.

Fig. 5-5: Catastrophic SCC Turbine Failure

The three most harmful contaminants introduced by condenser leaks are sodium, chlorides, and sulfates. Sodium will bond with other ions, such as hydroxides, chlorides, or sulfates, to form compounds capable of initiating corrosion mechanisms. For example, sodium hydroxide will increase the pH of water. If the pH is increased to high enough levels, corrosion rates of steel and copper will be increased. Sodium hydroxide is particularly harmful to stainless steel materials and turbine blades as it can initiate stress corrosion cracking (SCC). Sodium can also bond with other contaminates (such as chlorides) to form salts. These sodium salts, if transported to the steam cycle can deposit on boiler/steam generator tubes and turbine blades. When the deposits come in contact with water they can then act as initiating steps for numerous corrosion mechanisms, including pitting and SCC. Figure 5-5 shows a catastrophic failure of an LP turbine that was exposed to sodium salts and experienced SCC.

Tube Failure Mechanisms

Tube failure can be initiated on either the steam or water side of the condenser tube by either mechanical causes or corrosion.

- *Steam Side Mechanical Failure*

Drain lines containing high velocity steam or water can impinge on tubing and cause erosion to the tubes. This can be prevented by baffling tubes or distributing flow with perforated drain headers. Mechanical damage can also occur from failed LP turbine blades or debris from failed internal steam extraction expansion joints. Steam erosion can occur in the upper tubes near the turbine exhaust due to steam velocity or water droplet erosion.

- *Steam Side Corrosion*

Volatile gasses such as Ammonia can cause grooving of some materials.

- *Water Side Mechanical Failure*

Improper rolling of tubes into the tubesheet during construction of the condenser can result in tube leaks. High water velocity due to an excessive number of plugged tubes, as the condenser approaches end of life, or excessive tube sheet debris can result in erosion at the tube sheet inlet or within tubes.

- *Water Side Corrosion*

As the cost of copper increases, stainless steel condensers are becoming more common. Several failure mechanisms become an issue with the advent of this material. A failure mechanism that can significantly impact this material is Microbiologically Influenced Corrosion (MIC). Microbiological growth can occur on stainless steel but not on arsenic copper.

Under deposit corrosion can occur in both copper-alloy and stainless steel. Janikowski states, "It is not unusual to experience through-wall attack in three weeks on an improperly laid-up 0.71 mm (0.028-inch) thick TP 304 condenser tube" [2].

Installing Corrosion coupons is an effective means of monitoring the corrosion potential and thereby limiting or preventing condenser corrosion.

Corrosion inhibitors can be added to minimize corrosion in circulating water systems. During long outages, stagnant water can result in corrosion so the condenser should be kept dry or maintain the water flow in the tubes.

Tracking Condenser Tube Leaks

Tubesheet diagrams locating all plugged condenser tubes should be regularly updated at the plant for purposes of documenting whether the failure mechanism(s) is isolated or random. A corresponding table should also be maintained at the plant documenting how many tubes were plugged during each event, so that the frequency of tube failures can be determined.

Condenser tubes will typically provide an operating life of 30 to 50 years. When the curve for the number of failed tubes (plotted against time) starts to become exponential, then past experience has demonstrated that the condenser has less than two years of remaining life before chronic tube failures become a routine maintenance problem. Condensers are typically re-tubed when the number of failed tubes reaches 10 percent of the total number of tubes.

Eddy Current Testing to Locate Weak Tubes or Assess Condenser Condition

Eddy current testing (ECT) of condensers is a tool to help determine the remaining life of the tubes, trend tube degradation, and/or to locate tubes that may fail before the next major planned outage so they can be plugged. ECT has an accuracy of +/-20 percent and its accuracy is very dependent upon the equipment and the skill of the technician evaluating the data. Internal tube cleanliness will affect the ECT results so the tubes should be cleaned prior to testing. The ECT probe should fill about 80 percent of the interior tube area to obtain the most accurate results. If the probe fills 70 percent or less of the interior tube area, then dents or other minor surface irregularities could be misinterpreted as a wall loss.

Some ECT companies only use a two frequency, high speed process which may not be as accurate as other firms which use multiple frequencies to better define the defects. The ECT company should set up using an ASTM calibration standard of the same material, tube OD and wall thickness of the tube to be tested. It is very important for the ECT company to provide a report documenting the following items:

- Location of support baffles along the tube length
- Tube sheet map with the tubes color coded identifying % wall loss.
- Table of every tube tested with unique tube identifier and test results
- Each defect quantified along with the defect's location in the tube length
- Whether the defect is on the OD or ID of the tube
- % wall loss and voltage of each defect

At least two tubes should be pulled to verify the ECT data. The pulled tubes can be sent to the laboratory where the remaining wall thickness and defect locations can be verified and the failure mechanism documented.

Condenser tubes typically have thicknesses ranging from 18 BWG (0.049"), 19 BWG (0.042"), 20 BWG (0.035") or 22 BWG (0.028"). Tubes can fail by a variety of mechanisms and at various rates of attack. Any tubes which have a remaining wall thickness of 0.010" or greater should enable the tube to operate until the next major planned outage. Any tubes with a wall thickness of less than 0.010" should be plugged unless this results in a very large quantity of tubes to be plugged or causes more than 10 percent of all the condenser tubes to be plugged. When the total number of plugged condenser tubes exceeds 10 percent, then condenser replacement should be considered.

In lieu of testing all the main condenser tubes to determine the condition of the tubes and the main condenser's remaining life, a limited quantity of 5 percent of all the tubes could be eddy current tested which should provide a 99 percent confidence for statistical relevancy. The quantity of five percent of tubes must be randomly located throughout the entire main condenser (i.e. every 20th tube) in order to comply with a statistical analysis.

If there are problem areas within the tube bundle, then additional tubes could be eddy current tested to better define the tube condition in those problem areas and determine if any of those tubes should be plugged.

Plugging Condenser Tube Leaks

Once a conductivity excursion has been identified as a condenser tube leak then a plan needs to be developed to eliminate the tube leak. Typically it is required that a section of the condenser can be isolated to permit in-service tube plugging. On-line repairs cannot be conducted unless isolation valves are in good operating condition and seal effectively.

When plugging tubes, it is extremely important to plug both ends of a leaking tube. Most plants may rely on the tube counting method with a tubesheet drawing, but this could result in a tube end being plugged near the leaking tube and both ends of the leaking tube not getting plugged. It is recommended a tube be simultaneously plugged at both tubesheets using one of the following options to verify both ends of a leaking tube are properly plugged:

- Blow compressed air through the failed tube so the proper tube can be identified on the other tubesheet.
- Insert a cable or fiberglass rod through the failed tube until the cable or rod exits the other end.
- Shine a penlight through the failed tube so that someone at the other tubesheet can see the light.

"Insurance (or cluster) plugging" around a failed condenser tube is generally not recommended. If a condenser tube leak is located in a heavily plugged tube grouping of a known failure mechanism (i.e. ammonia grooving or inlet end erosion) where short term failure is imminent then insurance plugging is acceptable.

Tapered solid brass plugs have proven to be very reliable. However, these plugs protrude beyond the tubesheet face and make in-service leak checking difficult.

If a large number of tubes are removed (e.g. laning the tube bundle to promote steam flow) then dummy tube stubs are recommended to be installed and rolled into the tubesheet holes. A dummy tube is a 15 cm (6”) length of tube of the same OD and gauge as the original tube with one end of the tube crimped. A standard tube plug is to be installed in the rolled dummy tube, and the crimped tube end will prevent the unlikely event of the plug failing catastrophically and getting sucked into the condenser shell which operates under vacuum.

Leak Checks

Out-of-service condenser leak checks should be performed during each major planned outage. It is very important that the water temperature used to fill the condenser shell be >15°C (60°F) to stay above the nil ductility value of the carbon steel condenser shell plate welds. Carbon steel welds can become brittle and fail when exposed to stress at temperatures below 15°C (60°F), such as when hydrostatically testing a condenser. Flooding of condensers for leak checks is also required during every major planned outage.

Out-of-service, hydrostatic leak checks on bottom exhaust condensers are recommended during each major planned outage. Out-of-service leak checks on side or back exhaust condensers are also recommended during each major planned outage, and would be similar to checks performed when the units are in-service. As a good preventive measure, or if a condenser has chronic tube leaks or the tube failure rate is increasing, then leak testing is required during outages of sufficient length.

Condenser End-Of-Life Replacement

Condenser tubes will typically provide an operating life of 30 to 50 years. When the curve for the number of failed tubes (plotted against time) starts to become exponential, experience indicates the condenser tubes have less than two years of remaining life before chronic tube failures become a routine maintenance headache. Condensers are typically re-tubed when the number of failed tubes reaches 10 percent of the total number of tubes.

Several considerations that should be included in the life-cycle cost calculation when re-tubing a condenser are:
- Cost of new tubing
- Installation costs
- Fuel savings based on higher thermal performance
- Lower cooling water chemical treatment costs
- Reduction of lost generation due to turbine efficiency costs
- Reduction of boiler tube and high-pressure turbine cleaning costs
- Reduction of emergency outages and/or derates to plug leaking tubes

5.6 PREVENTING TURBINE DEPOSITION

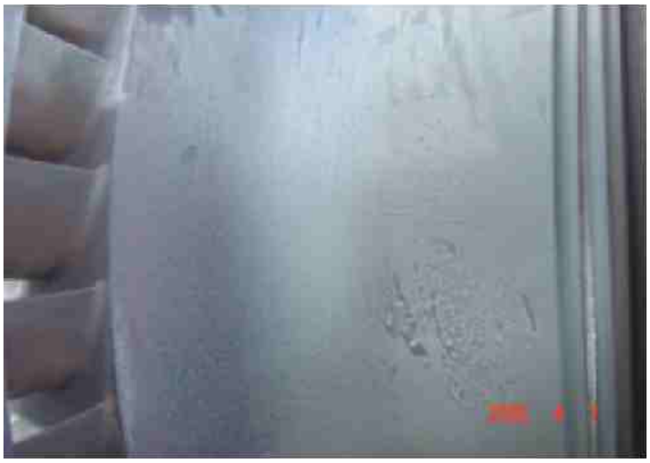
The best practice to maintain a deposit free turbine is to adhere to the water chemistry standards and action levels specified in Section 5.2. However, it is also important to understand the impurities that can result in turbine deposits and failure. Preventing these deposits requires not only adhering to the chemistry standards, but testing of the water during operation plus inspection and sampling during outages to assess the success of the water chemistry program.

Implementing a successful inspection and sampling program also requires knowledge about the areas on that turbine such as the phase transition zone (PTZ) that has a higher probability of deposits.

There are several contaminants that can deposit on the turbine and affect its performance iron, sodium, silica, chloride, and sulfate. The three most harmful contaminants introduced by condenser leaks are sodium, chlorides, and sulfates. When these contaminants are contained in a moist environment, they can lead to pitting which can turn into stress corrosion cracking or corrosion fatigue causing turbine blade failure. All turbine blade failures influenced by water chemistry have breakdown of passive protective layer as part of failure mechanism.

Figure 5-6: Catastrophic Turbine Failure (Sodium Salts)

Figure 5-7: Sodium on Turbine shaft



Sodium

Sodium will bond with other ions, such as hydroxides, chlorides, or sulfates, to form compounds capable of initiating corrosion mechanisms. For example, sodium hydroxide will increase the pH of water. If the pH is increased to high enough levels, corrosion rates of steel and copper will be increased. Sodium hydroxide is particularly harmful to stainless steel materials and turbine blades as it can initiate stress corrosion cracking (SCC). Sodium can also bond with other contaminates (such as chlorides) to form salts. These sodium salts, if transported to the steam cycle can deposit out on boiler/steam generator tubes and turbine blades. When the deposits come in contact with water they can then act as initiating steps for numerous corrosion mechanisms, including pitting and SCC. Figure 5-5 shows a catastrophic failure of an LP turbine that was exposed to sodium salts and experienced SCC.

Chlorides

Chlorides are one of the most corrosive contaminants in the turbine. Chlorides of a concentration of 100 ppb have a significant detrimental effect on pitting, which may act as a precursor to environment assisted cracking.

Figure 5-8: Turbine failure SCC-Chlorides

Sulfates

Sulfate is an anionic impurity that can contribute to corrosion related turbine failures.

Silica

Silica is considered as inactive to corrosion; however, silica will deposit on the back end of the LP turbine resulting in some efficiency loss. A silica analyzer needs to be used to maintain silica in steam below 10 ppb.

Figure 5-9: Turbine Iron & Silica Deposits

Iron

The main hazards associated with a high level of iron oxide in the steam are solid particle erosion of the initial turbine stages and deposits. Solid particle erosion can result from exfoliation from the super-heater and headers.

Deposits can result from iron present in the steam. The criteria for maintaining iron at acceptable limits are as follows:

- Dissolved iron should be consistently at 1 ppb or less.
- Suspended iron as defined by Millipores should be “snow white”.
    - o Millipore samples should be taken at the economizer inlet, deaerator outlet, deaerator inlet, and the HP heater drain. These samples should be checked weekly and more frequently if problems are encountered. It cannot be emphasized enough that if the Millipore sample has even a slight tint of color, the dissolved oxygen and or pH is not at optimal levels. Millipores should not exhibit any color.

Figure 5-10: Turbine Iron Deposits

Millipore is a very effective means of monitoring corrosion transport of suspended iron, and it should be a primary tool used for determining if oxygenated treatment (OT) is being operated correctly. Millipore monitors the iron collected as a water sample passes through a 0.45 μm filter. Two conventional means of evaluating the suspended iron collected by Millipore are visual and weight. A visual comparison chart or a measured weight can be used to evaluate the suspended iron present. However, to reliably operate a supercritical unit, suspended iron as defined by Millipores should always be snow white.

Turbine Phase Transition Zone Deposits and Inspection

Deposit Formation and Damage Mechanism

One area of the LP turbines that are especially susceptible to deposition is the PTZ. A thorough inspection of this area requires an understanding of the mechanisms that drive the damage. Svoboda and Dooley provide guidance on this subject in a recently released IAPWS paper titled "Phase Transition Zone Environments and Damage Mechanisms" [6] In the PTZ, expansion and cooling of steam occur which leads to condensation. "A number of processes that take place in this zone such as precipitation of chemical compounds from superheated steam, deposition, evaporation, and drying of liquid films on hot surfaces lead to the formation of potentially corrosive surface deposits". Liquid films up to 100-120 μm in thickness form on the steam turbine components as steam flows through the PTZ. Higher concentration of impurities result in much thicker films. The area in which the films develop is often characterized by "stains" and "water lines". The LP turbine damage caused by these films results in two very important failure mechanisms: corrosion fatigue and stress corrosion cracking. Although the deposits occur when the turbine is operating; due to the absence of oxygen, damage is unlikely during operation -- most damage occurs when the turbine is shut down and moist air is present. Maintaining the limitations defined in Section 5.1 to keep the impurities below the solubility limits and keeping the moisture level in a flowing dehumidified environment below 40 percent will minimize damage. These guidelines provided by Dooley and Svoboda are important and should be followed to avoid PTZ failures.

Inspection

Once understanding of the mechanisms is provided, specific areas for inspection can be identified. The identification of areas that contain "stains" and "water lines" define the profile encompassing the area where the cracking and damage occur. These "stains" and "water lines" do not form in straight lines but will follow a rather irregular pattern. "Thus a number of blade and diaphragm stages are always "touched" by these liquid films". The deposition will be "greater on the disk/steeple facing the steam flow". "The crevice areas between the blade and the steeple will also act as a crevice to concentrate any impurities. All of these can be the locators of the pits which initiate failure and damage". "The most common deposits are salts of chloride and sulfate".

In addition, liquid forms of hot NaOH solution can induce severe SCC even in the absence of oxygen. At special risk are stellites and austenitic steels, especially with high internal or external stresses. Low alloy and carbon steel are also at risk at welding joints when no heat treatment has been performed for stress relief.

Turbine Sampling

A part of preventing turbine deposition is to regularly perform quality turbine inspections. This is the mechanism by which feedback is gained to adjust the chemistry program. Although a world class turbine should be always deposit free, the only way to attain this status is to inspect the turbine during overhauls before cleaning and analyze and track the findings. It is very important to maintain an ongoing record of the chemical environment of stationary or rotating turbine blades. Turbine deposit characteristics and analysis provides a portion of that data. This data is needed to correlate the relationship between turbine reliability and efficiency and steam impurity concentrations. Use of such data can advance understanding of steam turbine corrosion, erosion, and scale/deposit formation, leading to better steam purity and boiler water operating limits. Always inspect the turbine when it is dry.

All turbine deposits should be sampled and analyzed for composition during any turbine overhaul, and whenever the turbine is inspected and the stationary and/or rotating blades are available for sample collection. The recommendations for collecting and submitting turbine deposit samples for analysis are mentioned in Table 5-5.

Table 5-5: Turbine Sampling Process

Turbine Sampling Process		
1	Digital pictures should be taken of areas sampled. These pictures need to include month, year, unit, which turbine blade section, and blade row.	
2	Note such items as the color, thickness and amount of deposit as well as the in-place condition (such as layer type, loose, flaky, adherent, etc.)	
	Dry samples	**Wet samples**
3	Collect sample >= 0.5 grams prior to blast cleaning or exposure to plant dust or dirt	If deposits are noticeable, but they do not have enough solid mass to obtain a dry sample, a section of the turbine can be washed with deionized water and the wash water can be collected for analysis. The wash water sample should contain the dissolved constituents that are present in the deposit.
4	Carefully scrape deposit sample into nonreactive containers such as polyethylene bags or plastic bottles	Collect wash samples in plastic bottles
5	Send samples to a lab for analysis including location of sample, digital pictures and comments from step 2 above. Any other pertinent data should be included with the transmittal, along with the reason for submittal of the samples and/or special evaluations to be made.	
7	A final report should be compiled	

Analytical data should be retained until all descriptive information listed above is received, so that it can be included in the final report. Maintaining optimal turbine efficiency and reliability, requires strict adherence to the water chemistry limits and action levels defined in Section 5.2 – Water Chemistry.

5.7 LABORATORY & CHEMICAL ANALYSIS

Operating supercritical plants with world class reliability and efficiency requires world class laboratory and chemical analysis. This requires developing an organizational structure that incorporates all of the necessary functions. These include effective monitoring, sampling, analysis, direction and goals, R&D, and oversight. The responsibility for chemistry functions should be divided between three entities. The recommended entities include: a general chemistry standards and control department (Service Corp), a central laboratory, and a plant laboratory.

General Chemistry Standards and Control Department

The General Chemistry Standards and Control Department provides the general guidelines and technical direction of chemistry related aspects for the organization. This department should include a person who has the role and responsibility for maintaining world class water chemistry throughout the corporation. This department should be responsible for: a) setting water related goals for steam generators, and b) ensuring that the right parameters are being monitored with the right precision at the right frequency. Supercritical plants require much cleaner water than subcritical plants. Specifying the instrumentation required to monitor the water with the required accuracy should also be the responsibility of this department. When problems arise that require additional technical expertise, this group would address those problems and coordinate the tools necessary to resolve the problems. This group should also be the primary interfaces with EPRI and other technical organizations. As a natural extension of this function, the direction for R&D should be provided by this organization.

Central Laboratory

A central laboratory owned and operated by the utility provides a mechanism to control standards of measurement that will meet the needs of supercritical units. This lab must have the ability to provide a complete extensive analysis of most all cations and anions (e.g. chlorides, sulfates, sodium, etc.) to a very high precision of 500 parts per trillion, PPT. Most commercial labs cannot analyze the water to this level and will simply provide a response of non-detectible. Owning and operating a lab provides better quality control and enables buying one high quality instrument that can be relied on by all plants. In addition to providing analysis of the routine water samples, the laboratory should have sufficient resources to provide a complete analysis of the boiler water for each supercritical plant on a quarterly basis. Due to the water standards required by supercritical units, precision analysis provides the means to reliable operation.

Although maintaining high water standards minimizes tube failure, it will occur. So, to provide understanding of these failures; thereby completing the feedback loop, the laboratory must also have the capability to analyze tube deposits and tube failures. State of the art equipment must be acquired to enable this function; one of the pieces of equipment that better enable this function is a Scanning Electronic Microscope (SEM).

A successful world-class corporation looks not only at day to day operations, but is focused on continuous improvement; therefore R&D is an additional function that the central laboratory houses. This R&D function meshes well with the other lab functions expanding their scope to focus on staying ahead of new and emerging technologies that could significantly impact the business by continually identifying, monitoring, prioritizing, developing and demonstrating technologies.

Plant Laboratory

A world class plant laboratory provides well trained personnel to reliably and repeatedly monitor the water, providing necessary assistance to the operator with daily monitoring of the plant. On-line continuous monitoring should be the primary tool used to control the water chemistry; however, this group provides the expertise to sample, analyze, and evaluate the results. This resident expertise enables the chemist to interface with operations during startup and during abnormal water conditions.

Roles of the plant chemist include:

- Champions and ensures water chemistry related practices that promote equipment reliability such as: layup of equipment during out of service conditions, reheat drying, and Flow Accelerated Corrosion (FAC).
- Proactively addresses abnormal water conditions before alarm conditions are reached.
- Directs that the unit be removed from service when unit conditions preclude operation within the operating specification.
- Provides continuity by completing the loop between daily water chemistry operation and observed deposits on or failures of turbine blades, boiler tubes, etc.
- Evaluates water related failures and develops an action plan to correct those failures and a plan to prevent them in the future.
- Ensure that corporate policies are adhered to, enabling reliable efficient equipment operation.
- Provides on-site chemical expertise.

5.8 CHEMICAL CLEANING CRITERIA AND DETECTION METHOD

Timely and effective chemical cleaning of a supercritical unit before heat transfer is significantly impacted can be the lifeblood of a steam generator. Accurately detecting the scale on the tube ID before it significantly impacts heat transfer and tube life can be very challenging. This section provides guidance on utilizing best available technology to measure oxide deposits and for setting up criteria to enable reliable steam generator operation.

Historical methods of determining tube deposits include removing a tube sample from the steam generator at a location most likely to have the heaviest deposit during major outages and scraping the tube sample, or bead blasting it. This used to be an effective method as long as the only deposits to be removed consisted of iron transported from condensate and feedwater systems. As less corrosive water treatments became known, it became practical to extend the time between cleanings; however, duplex insitu oxide layers tend to form making the old detection methods ineffective.

Under the old methods, while operating on all volatile treatment reducing (AVTR), the steam generator would be chemically cleaned when the deposit weight obtained from scraping the tube sample reached 12 g/ft2 deposit, and this would typically occur within 18 to 36 months of unit operation.

Supercritical units operating on OT form very tenacious deposits which contain three distinct layers. These layers are defined as spinel, hematite and magnetite. The most outer layer is hematite and is the corrosion product deposition from the corrosion of the condensate and feedwater piping. The middle layer is a magnetite layer, which is actually from the oxidation of the base metal and is grown insitu. The third layer which is next to the base metal is the spinel layer which is also from the oxidation of the base metal and is grown insitu. The second and third layers combine to form the duplex insitu oxide layers described earlier. The deposits generated by operating supercritical units on oxygenated treatment has prompted a need for improved technology, the scanning electron microscope (SEM), to enable reliable steam generator operation.

The following discussion will reference use of a scanning electron microscope to provide an understanding of tube oxide deposits, and to show why an SEM is required for accurate tube sample analysis and to show how it can be used to evaluate the condition of tube samples.

The duplex layer that is being formed on supercritical waterwall tubes is a very tenacious and hard layer. So much so that the typical scraping method does not remove this layer at all when deposit weight analysis is performed. It is also important to note that the bead blast method used to determine deposit weights also does not remove the spinel layer that is formed.

An SEM was used to generate the micrographs shown in Figure 5-11 and Figure 5-12. The micrographs show two tube metallographic specimens that were examined for evidence of ID scale removal after a bead blasting operation. The micrographs show duplex ID scale segments still attached after the bead blasting operations were completed.

The average measurements of the layers shown in Figure 5-11 are:

Spinel	11.2 µm
Magnetite	32.7 µm
Hematite	2.22 µm

Figure 5-11: SEM 160X (Cropped)

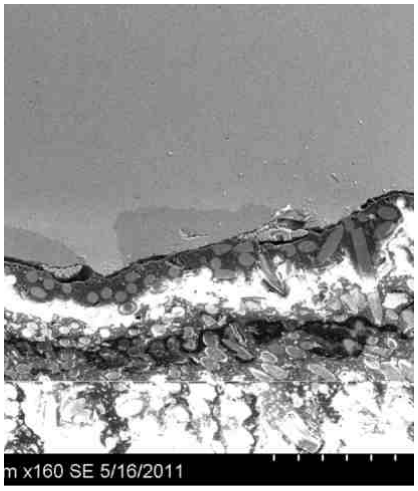
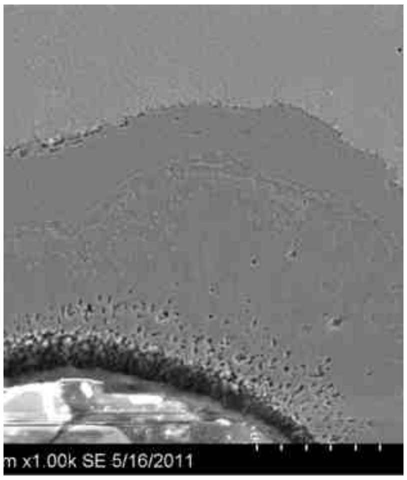


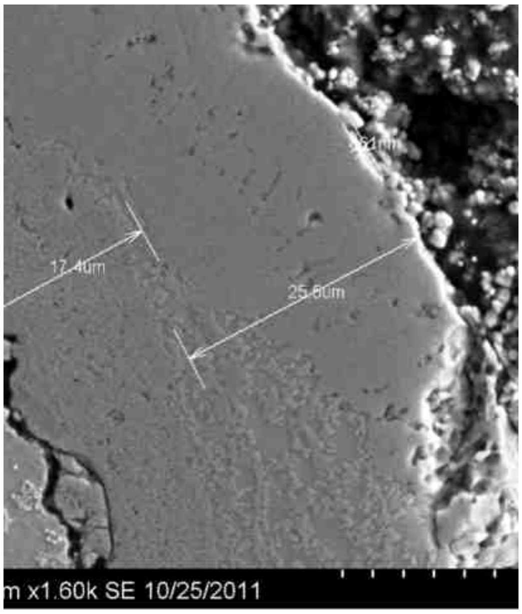
Figure 5-12: SEM 1000x



The micrograph shown in Figure 5-13 shows the results from another sample from a supercritical unit. It was also produced with an SEM of the ID scale and is etched to reveal the different components present. The layer next to the metal substrate (left border) is the spinel layer. The next layer is magnetite and the outer layer shown is hematite. The average thickness measurements of each layer of this sample are tabulated below.

Spinel	17.4 µm
Magnetite	25.8 µm
Hematite	0.861 µm

Figure 5-13: SEM 1600x



Thermal conductivity is determined by the porosity of the deposit and by the thermal conductivity of both the structural material (the tube) and of the medium which fills the pores. The insitu grown oxides are layered and have porosity. This layering of the duplex oxide has a significant impact on the true thermal conductivity resisting heat transfer between the tube metal steam side surface and the cooling medium. To avoid supercritical waterwall cracking it is essential that undue elevation of tube metal temperatures be avoided. Metal temperature is determined not only by the amount of deposit but to a considerable extent the deposit structure and conditions of heat transfer. Not only is porosity a key but delamination of these different layers can also have a significant impact on heat transfer and thus metal temperature. An air gap between the layers drastically decreases the thermal conductivity of the deposit and thus increases the tube metal temperature.

Tube Sampling and Frequency of Chemical Cleaning

To address uncertainties, experience has established a minimum chemical cleaning frequency for supercritical units in addition to requiring tube deposit thickness determination instead of deposit weight analysis for determining when a chemical cleaning is necessary. For supercritical units operating with OT, regardless of tube sample oxide scale thickness, a chemical cleaning should be performed at a minimum once every 15 years due to increased uncertainty of finding the needle in the hay stack (the tube in the steam generator with the thickest oxide). For deposit thickness determination, anytime the total thickness of the three layers exceeds 40 micron (1.57 mils) (approximately 11.7 g/ft2) a chemical cleaning needs to be scheduled. Anytime the deposit thickness exceeds 100 micron (3.94 mils) (approximately 29 g/ft2) the unit needs to be chemical cleaned immediately. It should be noted that a non-delaminated deposit layer of 100 microns would increase the crown metal temperature of a water wall tube by approximately 11.8°C (21.2°F). As such, tube samples should be taken at a minimum every major outage for supercritical units.

When a chemical cleaning is performed, pre- and post-cleaning tube samples should to be taken. The pre-cleaning samples should be analyzed using the deposit thickness measurement instead of deposit weight. Two samples to determine the need for chemical clean should be taken. The first sample should be taken in the heaviest deposit area that has been taken in the past. This sample is to confirm if OT has been working correctly. On universal pressure (UP) boilers, a second sample is typically taken in a third pass tube approximately 1.8m down from roof line. Because deposit thickness determination is being performed, these tube samples only need to be 30.4cm (12”) in length.

Boiler Performance Analysis 6.0

6.0 BOILER PERFORMANCE ANALYSIS

6.1 SUMMARY

There are many factors that influence supercritical boiler and combustion performance. Unit design and fuel quality have a major influence on a plant's performance. Plant operations, performance, load response, reliability, and capacity are all inter-related. So, any approach to optimization/management of performance should be comprehensive in nature, taking into account mechanical adjustments of the firing systems, fuel quality, boiler cleanliness, airflow measurement, furnace oxygen control, and many other factors.

In an effort to identify stealth or "hidden" performance issues, a program must be organized with the plant departments committed and working together to achieve and preserve plant performance.

With a shortage of domestic coal and newly enacted environmental regulations, Indian power plants must perform well, or suffer the consequences of increased fuel costs, poor reliability, and reduced generating capability. During plant operations, thermal energy is lost through a plant's stack, rejected to the cooling tower, and/or used by the plant auxiliary equipment. Thus, an effective plant performance program encompasses various program activities that are used to evaluate, sustain, improve, and preserve a boiler's performance.

This chapter summarizes various areas affecting boiler performance including: coal quality, systems equipment management and steam generator performance. The intent of Chapter 6 is to provide an overview of how to apply proven and "best practices" that have been utilized for comprehensive management of combustion and boiler performance. Then, having senior management involved, defining processes and creating divisions of responsibility are key to a program's success.

Other essential items include tools and equipment required to collect representative samples for analysis. This defines the measurement process and best practices or tools required to identify and reduce gaps in performance. A performance preservation program is a process that requires dynamic tools and processes, grounded on fundamentals.

6.2 CONTROLLABLE HEAT RATE LOSSES

Plant heat rate is the measure of how efficiently a fossil-fueled power plant converts the chemical energy from the fuel into electrical energy. There are many factors that influence a supercritical plant's heat rate. However, it is important to understand that some plants are built and designed to be more efficient than others. A boiler's design pressure and temperature ratings certainly impact heat rate, while variations of the plant components, the stages of reheat, feedwater heaters, pump design, fan design, ambient conditions, and operations also influence the performance. When assessing a plant's heat rate, the gross heat rate is calculated using the total unit heat input and the gross electrical generation produced. Net heat rate is calculated using the total heat input and the net electrical generation leaving the power plant.

Fuel quality has a major influence on a plant's heat rate. With new enacted environmental regulations, Indian power plants must perform well. Thus, in addition to the challenges with coal shortages, controllable heat rate optimization is especially important for Indian thermal power plants to ensure they meet the new environmental regulations.

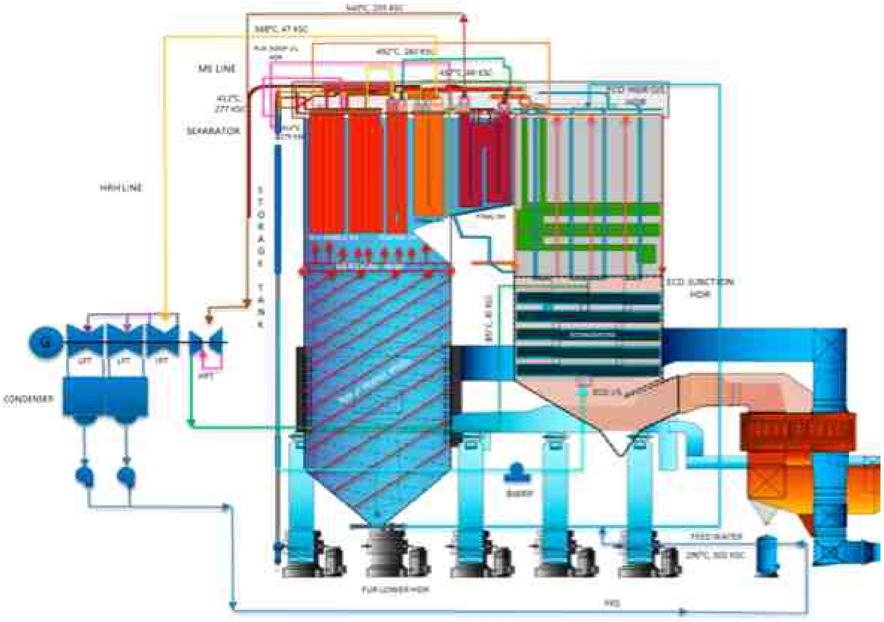
Figure 6-1: Artist's Rendering of a 600 MW Supercritical Plant

Some of the major benefits of improving heat rate include:

- Fuel savings
- Lower greenhouse gas emissions
- Improved reliability
- Water conservation
- Increased power generation

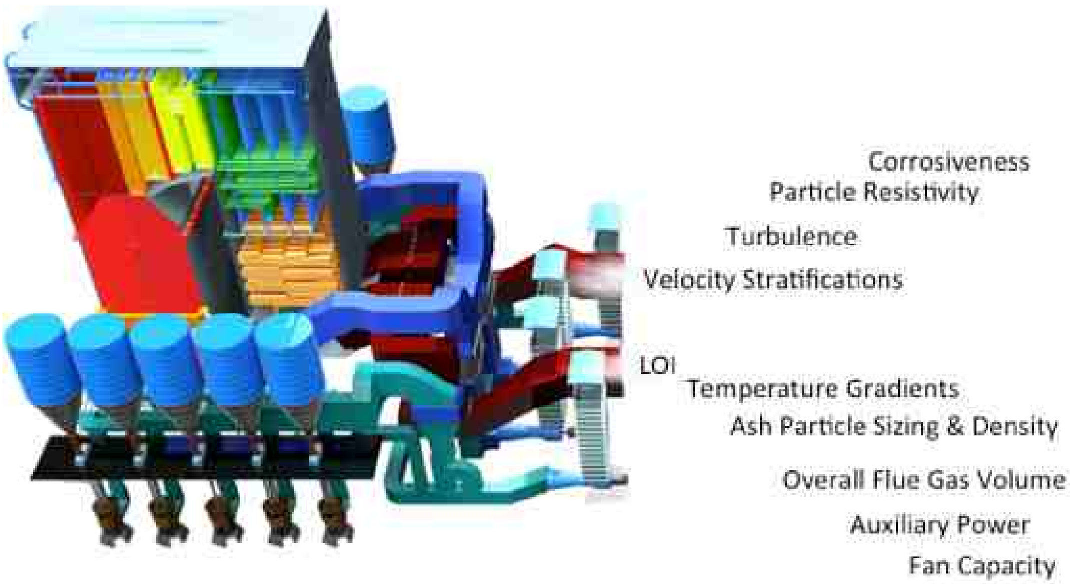
The overall thermal efficiency, reliability, and emissions from a large supercritical steam generator are very much influenced by the combustion process, slagging, equipment condition, reliability, and a unit's capacity factor. As units begin to age, the performance typically declines. However, with a good program in place, the accounted losses can be recovered in many cases. This program must include monitoring processes to evaluate the thermal performance of the integrated boiler and turbine cycle (Figure 6-2).

Figure 6-2: Schematic of a 600 MW Supercritical Steam Power Plant



Combustion efficiency is very much affected by fuel quality and fuel characteristics. Fuel changes, poor combustion, and equipment condition can consume a boiler manufacturer's margins for the firing equipment, metallurgical limits of alloys, and the boiler's thermal efficiency. In addition, flue gas volume and constituents can have adverse effects on the air pollution control equipment installed, if not properly managed. Some of the impacts are shown in Figure 6-3.

Figure 6-3: Influence of Non-Optimal Combustion on Air Pollution Control Equipment



Through experience gained over the past decades, we have learned that optimal performance demands optimal control, measurement, and accuracy of the air and fuel delivery systems. Heat input and distribution are even more important with supercritical *"once through"* units, where evaporation occurs in various levels of the furnace walls (depending on load). With that said, it should be noted that primary airflow, secondary airflow, fuel flow measurement, and sizing of the pulverized coal to the furnace are of paramount importance. Proportioning of these inputs to the furnace influences flame propagation, firing patterns, and overall combustion efficiency [1]. Outside of normal daily monitoring and trending of performance with "online" and "real-time" performance engineering tools, periodic comprehensive and representative diagnostic tests should be completed to supplement the permanent plant instrumentation. Furthermore, internal plant simulation and operational training for controllable heat rate optimization with a dedicated system and centralized processing center is highly recommended.

Photograph of the operations simulator center shown in Figure 6-4 represents a "world class" facility for operational training and simulation at the NTPC Sipat Thermal Power Station.

Figure 6-4: World Class Training and Operations Simulation Program at SIPAT Thermal Plant

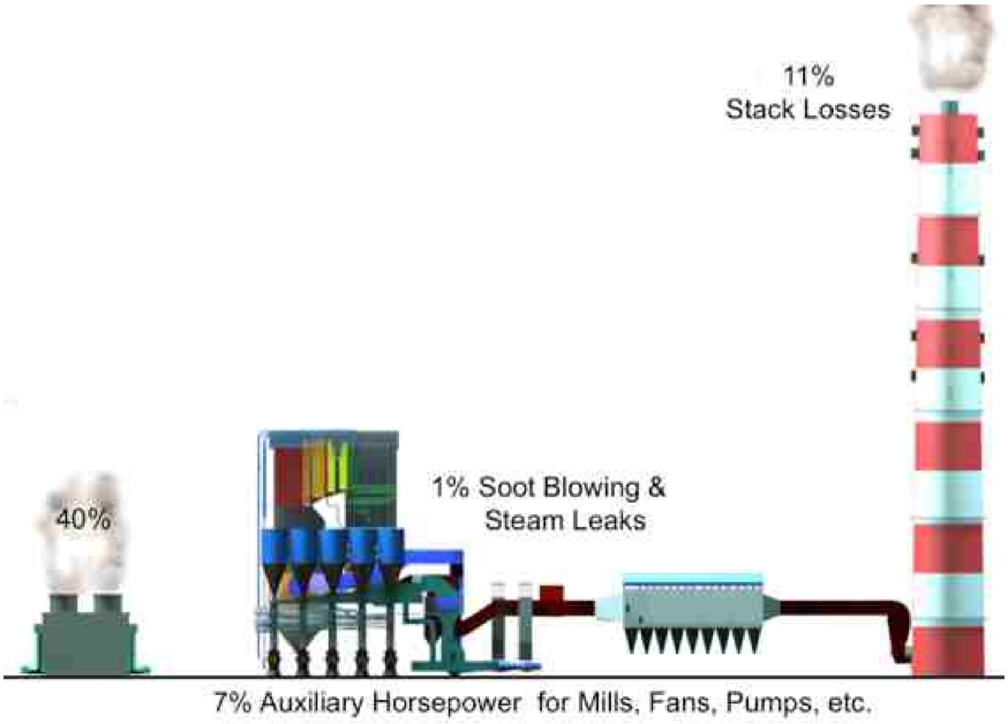
Managing plant heat rate should ideally be evaluated in "real-time," with thermodynamic modeling tools supplemented with weekly, monthly, quarterly, and semi-annual plant performance checks of the boiler equipment and auxiliaries to validate plant instrumentation and the mechanical tuning demands for the plant equipment. As with any thermal performance program, it is also essential to have accounting measures for the fuels consumed and accurate kW generation to determine a plant's heat rate [2]. Thus, fuel preparation equipment should include measurement systems for fuel quantity and quality. For new modern supercritical power plants, scales, blending systems and nuclear analyzers for managing a unit's heat input should be considered.

To interpret a plant's thermal efficiency and evaluate the heat losses, an accurate measurement of both turbine cycle heat rate and boiler efficiency is essential. When assessing a plant's heat rate, all of the plants equipment, required auxiliary power consumption, and equipment condition must be taken into consideration. Corrections can then be made against the original design variables when benchmarking. Such corrections would include variations such as circulating water temperature, fuel quality, turbine exhaust pressure, and equipment modifications/condition. Two test procedures commonly utilized for evaluating plant heat losses on the turbine cycle and boiler are:

- **Gross Turbine Cycle Heat Rate (ASME, PTC 6)**
    - This includes only the heat input to the turbine cycle.
- **Boiler Efficiency (ASME, PTC 4.0)**
    - This is used to determine the heat input to and losses in the boiler.
    - A "unit" heat rate includes all heat input to the boiler (including all fuels used for ignition, start-up, and primary combustion).

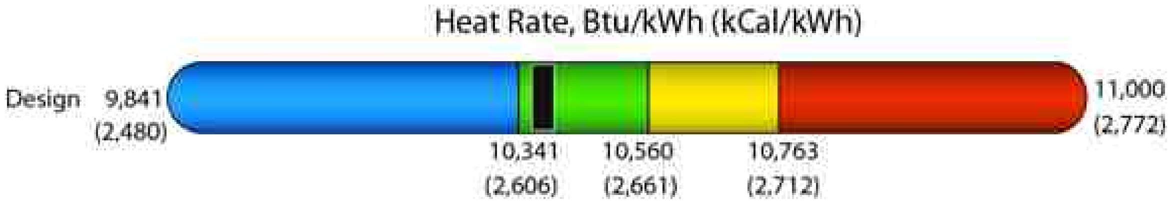
A good heat rate program must be comprehensive and goal oriented towards achieving efficient, effective and sustainable power production and avoiding excessive heat loss by monitoring overall thermal plant performance losses. For example, an illustration representing a scenario of heat losses for a 41 percent thermal efficiency PC fired supercritical unit is shown in Figure 6-5.

Figure 6-5: Thermal Efficiency Loss Example



In an effort to assess the controllable losses, a process must first be developed. It is not uncommon for controllable plant heat rate to vary as much as 10 percent, especially with aging plants. Comprehensive and "plant interactive" performance programs require "buy-in" from senior management and demand proper organization to help ensure that the program's roles, process, and procedures are implemented properly to achieve a goal and sustain a plant's target heat rate. It is a good practice to have dashboard indicators posted for plant personnel to understand operations (See Figure 6-6 for one example).

Figure 6-6: An Example of a Plant Heat Rate Target Display



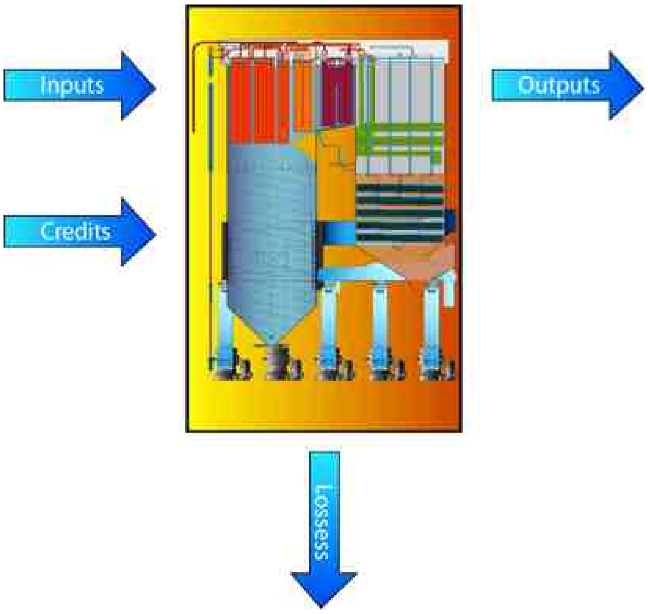
Combustion and Boiler Efficiency

In most large pulverized coal fired boilers, the boiler efficiency loss accounts for about 10-15 percentage points of overall plant efficiency loss, depending on the fuel properties. However, if performance is not optimal, the "controllable" losses can result in an even greater degradation in boiler and overall plant performance.

The controllable losses are often related to dry flue gas and carbon losses, which are in turn related to combustion. Since half of the losses are typically dependent on the fuel and ambient condition, the best efficiency can be achieved through optimal settings and tuning of a boiler and its auxiliary equipment.

A steam generator's efficiency is the ratio of energy output to the energy that is input into a system. Sometimes boiler efficiency is referred to as fuel-to-steam efficiency. It accounts for the effectiveness of the heat exchanger as well as the radiation and convection losses. The purpose of performing an efficiency test is to determine how much energy is coming out of the system compared to how much energy is put into the system (Figure 6-7).

Figure 6-7: Boiler Input, Output, and Losses



The efficiency of a boiler is determined by two methods (direct and indirect):

1. The Input-Output Method
2. The Heat Loss Method

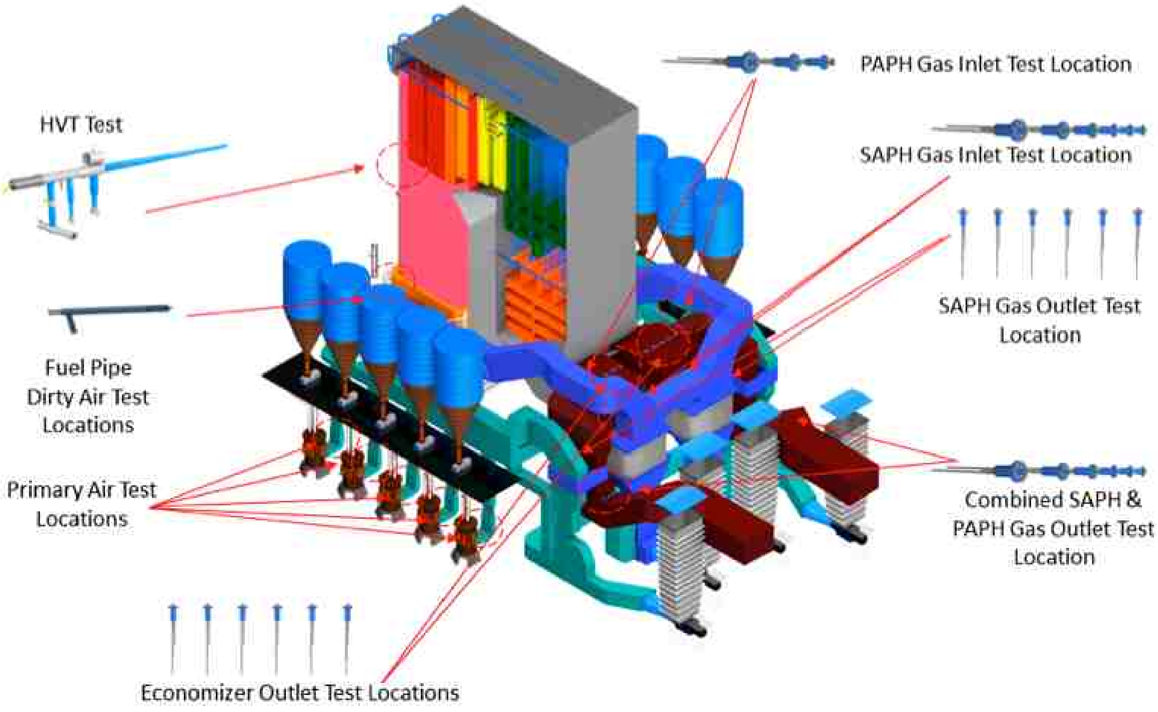
Input-Output Method:

The Input-Output efficiency measurement method is based on the ratio of the output-to-input of the boiler. The actual input and output of the boiler are determined through instrumentation and the data are used in calculations that result in the fuel-to-steam efficiency. To accomplish this, accurate scales, gravimetric coal feeders, and accountability for all fuels (and quality of fuel) are essential.

Heat Loss Method:

The Heat Loss efficiency measurement method is based on accounting for all the heat losses of the boiler. The actual measurement method consists of collecting representative samples of coal, flue gas, and ash for data compilation and then subtracting the percent the total percent stack, radiation, and convection losses from 100. The resulting value is the boiler's fuel-to-steam efficiency. The heat loss method accounts for stack losses, radiation and convection losses. The diagnostic testing locations in a boiler are shown in Figure 6-8.

Figure 6-8: Comprehensive Testing Locations, 600 MW Supercritical Unit



To evaluate and react to controllable losses in the boiler, communication is vital. Table 6-1 is an example of how to put a heat loss evaluation program into action.

Table 6-1: Example of Putting a Heat Loss Evaluation Program

Description of Losses	**Design Boiler Efficiency**	**Actual Efficiency**	**Target Efficiency**	**Immediate Action Items**
	89.2%	**83.15%**	**88.12%**	
Dry Flue Gas Loss	3.95%	5.4%	4.0%	• Sustain furnace exit gas temperature by optimizing combustion and lower furnace heat transfer through combustion optimization • Reduce Boiler and Air Preheater Air In-leakage • Optimize excess air set-points
Loss due to H_2 in Fuel	3.9%	4.3%	4.2%	• Consistency in fuel supply; Coal Blending
Moisture in Fuel	1.5%	4.2%	2.0%	• Improve fuel quality and delivery
Moisture in Air	.20%	.25%	.23%	-
Losses due to Carbon in Ash	.60%	2.0%	.80%	• Combustion optimization, Including: Mill and fuel line performance optimization; total airflow set-points; Windbox pressure, air distribution and coal fineness control.
Radiation and Convection Losses	.15%	.20%	.15%	• Weekly Infra-red Thermography Assessments; Complete Insulation and Expansion Joint Repairs as needed
Unmeasured Losses	.50%	.50%	.50%	• Agreed upon
Total Losses	**10.8**	**16.85**	**11.88**	

A similar process can be used for the turbine cycle to assess condenser performance, steam temperature control, de-superheating spray flows, make-up water, managing high-energy piping, etc. There are numerous controllable boiler operations and maintenance factors that affect unit heat rate. However, some of the most prevalent and often overlooked controllable heat rate factors include the following:

Examples of Common and Controllable Heat Rate Variables

1. **Combustion and boiler optimization begins in the coal yard**

   - Fuel preparation should be optimized in conjunction with fuel feed controls, quality, blending techniques and sizing since heat rate changes with fuel quality. The variations should be understood and managed accordingly. See Figure 6-9.

Figure 6-9: An Artist's Rendering of a Coal Yard

2. **Turbine throttle pressure and temperatures of superheated and reheated steam**

   - Steam temperature and pressure must be controlled at near the turbine design values for best heat rate operation.

3. **Cycle losses due to leaking, vents, drains, and internal turbine leakage** *(due to steam purity problems that result in turbine deposits)*

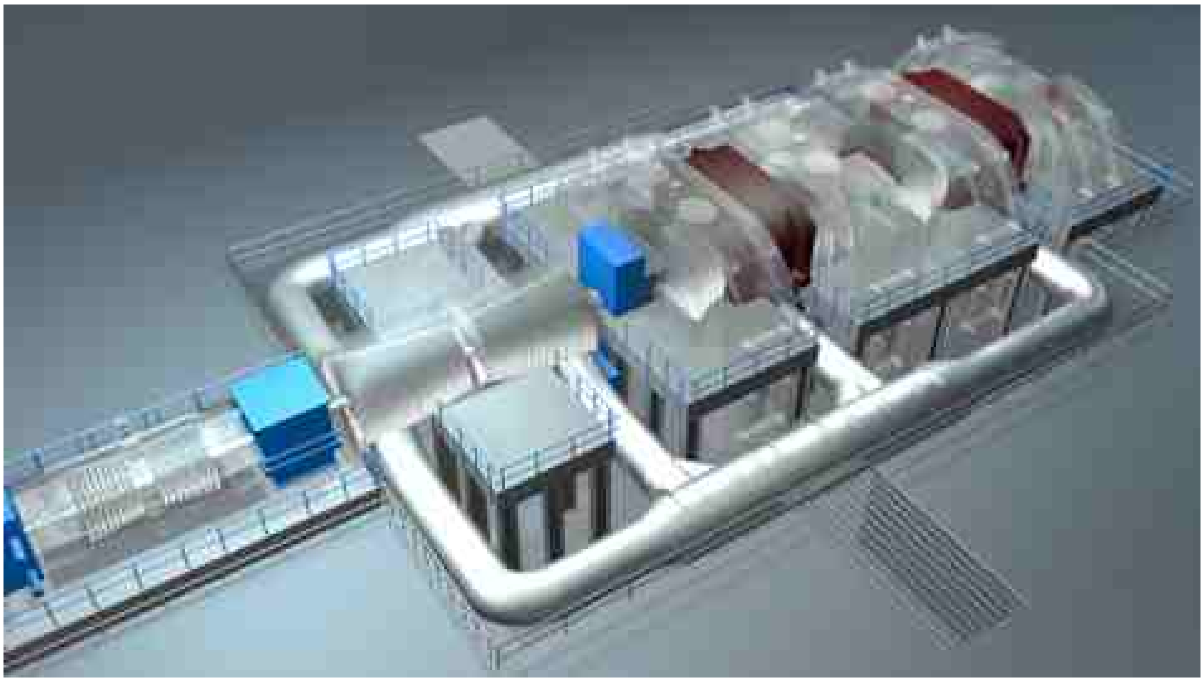
   - Special attention should be given to drains and vents to the condenser. Sometimes a very large amount of heat bypasses the turbine and is wasted undetected, to the condenser causing condenser vacuum losses.

4. **De-superheating spray flows**

   - o If high spray water flow to the superheater or reheater is experienced, this is indicative of high furnace exit gas temperatures related to combustion. Furthermore, elevated reheat spray flows can result in significant heat rate penalties.
   - o Steam purity (or impurities) will cause dissolved solids in the de-superheating water flow to the superheater or reheater. This can result in turbine blade deposits that result in either efficiency or capacity loss.

Note: reference turbine and water chemistry (Chapter 5) for more detail. Figure 6-10 is a steam turbine conceptual illustration for a 600 MW supercritical unit installed in India.

Figure 6-10: Example of 600 MW Turbine on an Indian Supercritical Unit



5. **Boiler air in-filtration, air preheater and overall system air in-leakage can negatively impact combustion, efficiency, and overall heat rate**

   - o Air in-leakage on balanced draft boilers can be very problematic being that the excess oxygen analyzers cannot distinguish post combustion air filtration from actual excess air.
   - o Furthermore, air in-leakage bypassing the air preheater negatively influences X-ratio (or the air to flue gas ratio). If not managed, erosion and leakage due to erosion, especially with domestic (high ash) Indian coals can result in unfavorable O_2 rise curves.

- Air preheater leakage should be less than 10 percent on regenerative air preheaters. When the leakage increases, the dilution of the flue gas results in a depressed flue gas to stack temperature. This is due to the dilution from cold combustion air. Therefore, for boiler efficiency calculations, the corrected to no-leakage temperature needs to be utilized. If not completed properly, these depressed flue gas temperatures from convective pass or air preheater leakage can suggest a false sense of good and efficient operations. Furthermore, air in-leakage can limit fan capacity, increase auxiliary power, negatively impact the air pollution control equipment and/or result in acid dew point corrosion issues.

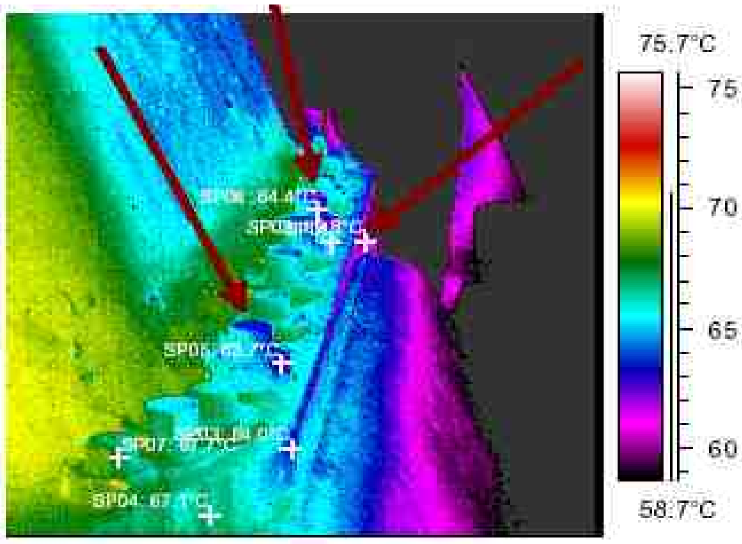
- Furnace to the stack leakage should be periodically audited, managed and reduced best as possible.

- Excessive and tempering airflow bypassing the air preheaters can negatively impact X-ratio.

- Once the leakage across the duct or air preheater is calculated, the outlet temperature can be corrected to indicate what the temperature would be if there was no leakage. To further correct the outlet temperature, the inlet gas temperature to the air preheater can also be corrected to determine additional losses due to air in-leakage upstream of the air preheater.

- Infrared thermal evaluations and audits of expansion joints, casing and all potential paths of air infiltration should be periodically conducted. See Figure 6-11.

Figure 6-11: Infrared Image (Courtesy of NTPC, CenPEEP) [17]



6. Sootblowing Performance

- Soot blower optimization is critical for achieving best steam temperatures and reduced exit gas temperatures through optimal heat transfer.

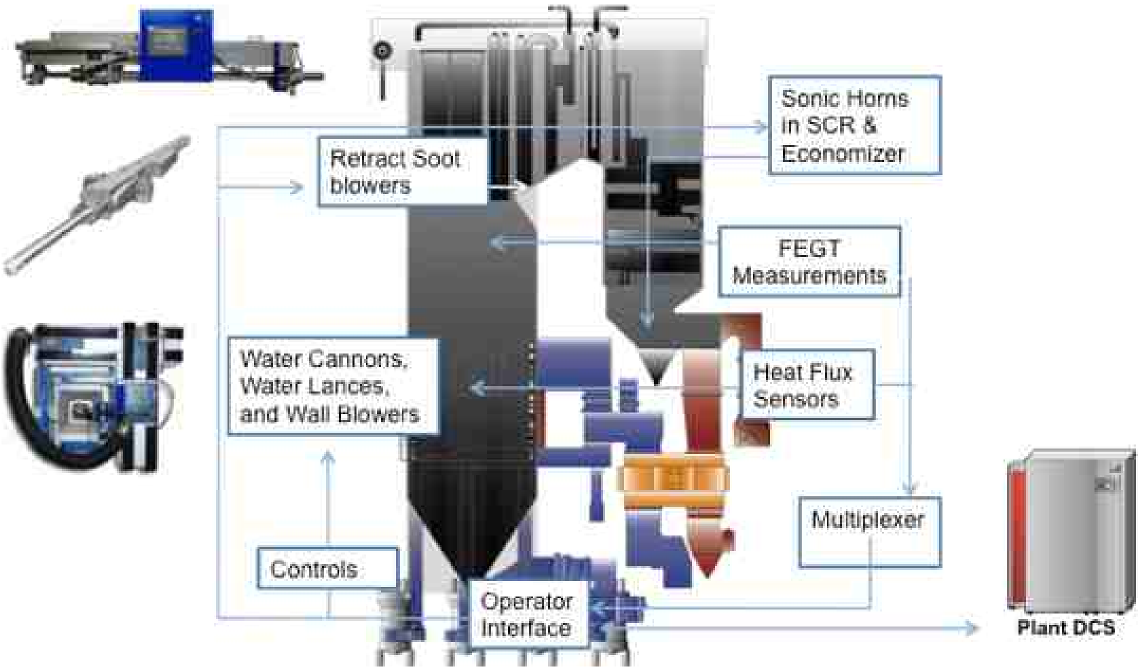
- Soot blower performance should not only be by inspection, but also by effectiveness. For example, when firing higher slagging index coals, the furnace water wall (IR) soot blowers are very important in cleaning the water walls to allow heat absorption that will depress furnace exit gas temperature. The lower furnace blowers are “preventative” blowers in that they clean water wall surfaces to allow increased heat absorption, reducing furnace exit gas temperature below the softening temperature of the ash and preventing slag from accumulating. Furthermore, by suppressing the bulk furnace gas temperatures, this also helps to reduce NO_x production. Long retractable (IK) blowers are “reactive” blowers that remove slag after it has already formed.

  The long retractable blowers are only intended to remove accumulations of friable ash and not heavy slag. It is also important to keep in mind that blowing long retracts in the upper furnace can sometimes be counterproductive because furnace exit gas temperature will often remain above the fusion temperature of the ash after they are blown as slag will rapidly accumulate after slag is removed from the boiler tubes. Also, poor combustion and/or ineffective wall blowing will facilitate sustained operation with the Furnace Exit Gas Temperature (FEGT) exceeding ash fusion temperature and slag deposition occur rapidly immediately after blowing. Considering this, slag formation must be controlled by preventing its deposition in the first place and thus efforts should be provided that improve heat absorption in the lower furnace, depressing FEGT below fusion temperatures of the ash.

- Advanced boiler cleaning tools often include:

  - Intelligent Wall Blowers and Long Retractable Blowers that interface with heat flux sensors (Figure 6-12)
  - FEGT Measurement
  - Thermodynamic Models and the associated controls
  - Water Cannons

Figure 6-12: Typical Intelligent Soot blowing System Architecture



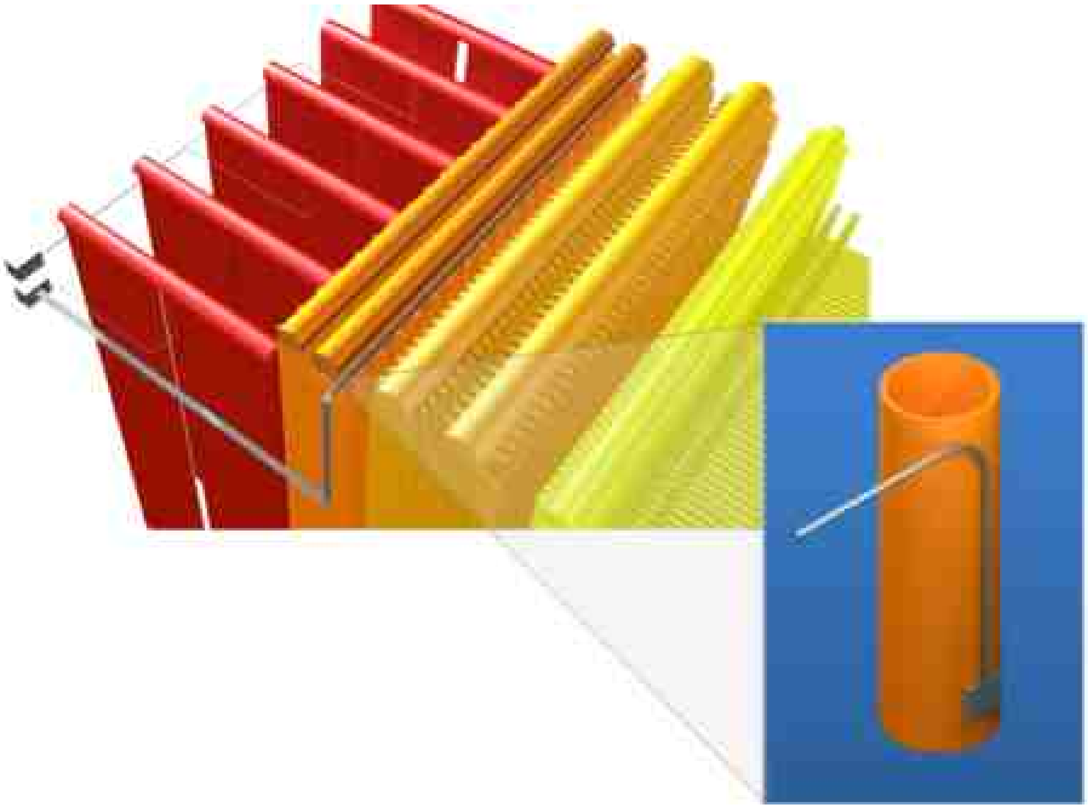
7. Furnace and boiler exit gas temperature

- Furnace exit gas temperatures (FEGT) can become elevated due to poor combustion and non-optimal lower furnace heat transfer. High FEGT can also result in slagging, fouling, high draft losses, increased air-in leakage, and increased de-superheating spray water flows.

- Considering the previous, real-time FEGT monitoring devices and tube metal thermocouple systems are recommended (Figure 6-13).

- Tube metal temperatures at the furnace exit should be monitored for reliability and profiled against local flue gas measurements to ensure uniform heat distribution. Pad weld thermocouple systems are used for identifying multiple tube circuit temperatures at the furnace exit.

Figure 6-13: Example of a Conceptual Tube Metal Thermocouple System Installed in the Penthouse of a Supercritical Unit



- o The exit gas temperature from the furnace to the economizer should be periodically measured and compared to design, or best-expected temperature. To do so, use of water-cooled High Velocity Thermocouple (HVT) measurement probes should be utilized (Figures 6-14, 6-15 and 6-16).

Figure 6-14: Photograph - Testing with a Water-Cooled HVT Probe

Figure 6-15: Furnace Exit HVT Traverse (Manual/Temporary)

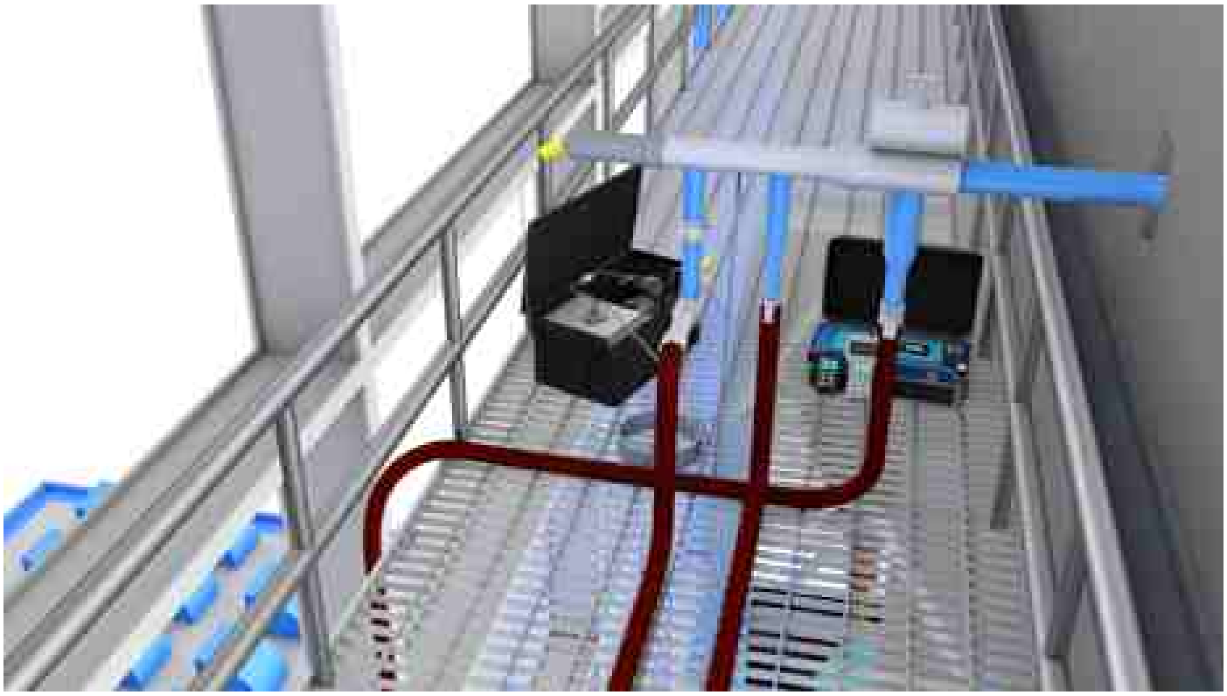
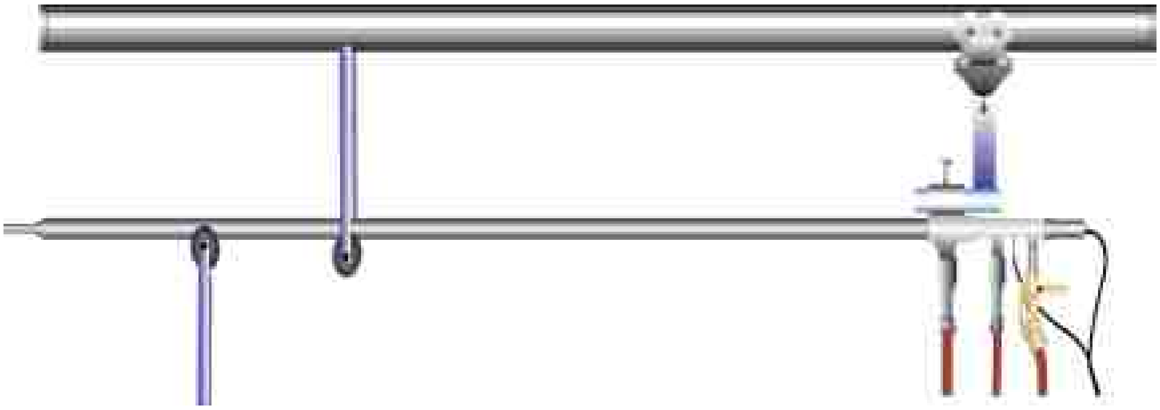


Figure 6-16: High Velocity Thermocouple (HVT) – with Monorail System



- By design, most boilers should not exceed an FEGT of 1,204°C (2,200°F) at the furnace exit, 412.8°C (775°F) at the economizer outlet and 140.5°C (285°F) corrected to no-leakage temperature at the air preheater exit.
    - In cases where higher sulfur fuels are fired, the average cold-end temperature must be maintained higher. However, in the case of most thermal plants in India, operations with lower exit gas temperatures (assuming low sulfur fuels are being fired), is certainly a best practice.

    - Poor combustion, slagging, fouling and/or aggressive fuel and air staging can influence the exit gas temperatures as well as the performance of the air preheater.

- o If the economizer exit gas is above 426.7°C (800°F), the metallurgical limit of carbon steel can result in deformed air preheaters and excessive air in-leakage.

8. **Combustion Airflow Control and Excess Air**

- o Proper supply and distribution of combustion airflow is something that is absolutely essential, but often overlooked. Primary and Secondary Airflow should be accurately measured and controlled to 3 percent accuracy. Examples of local testing ports that should be used for periodic calibration are shown in Figures 6-17 [3].

Figure 6-17: Typical 600 MW Supercritical Unit with Representative Testing Locations for Periodic Measurement Calibrations

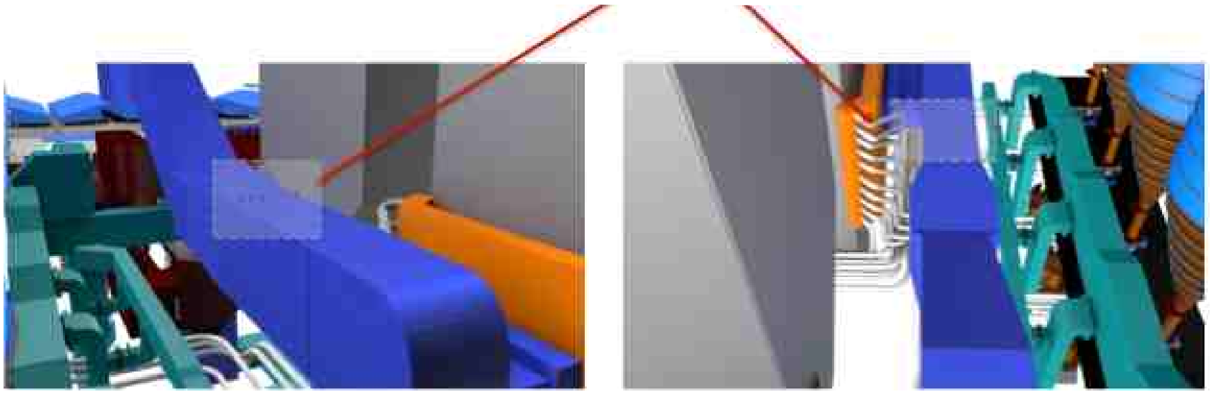
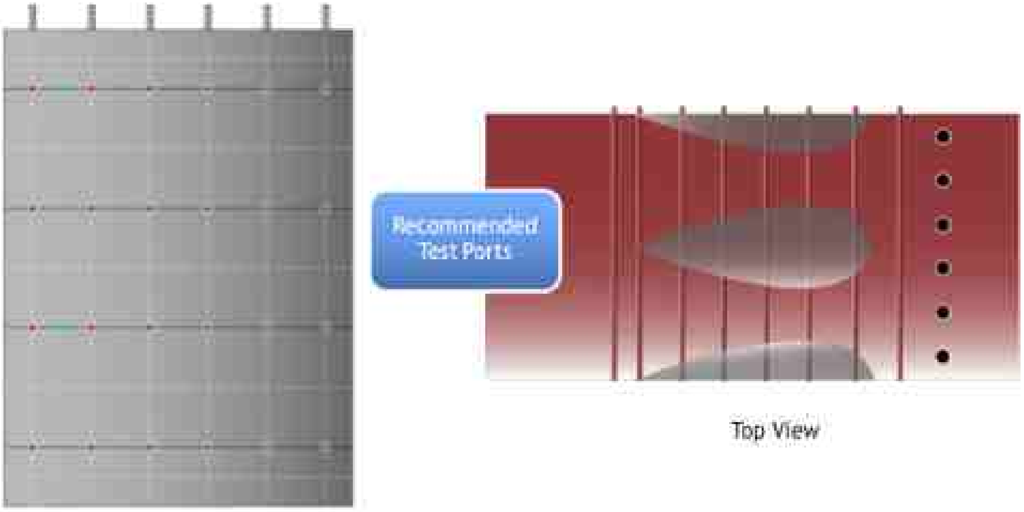
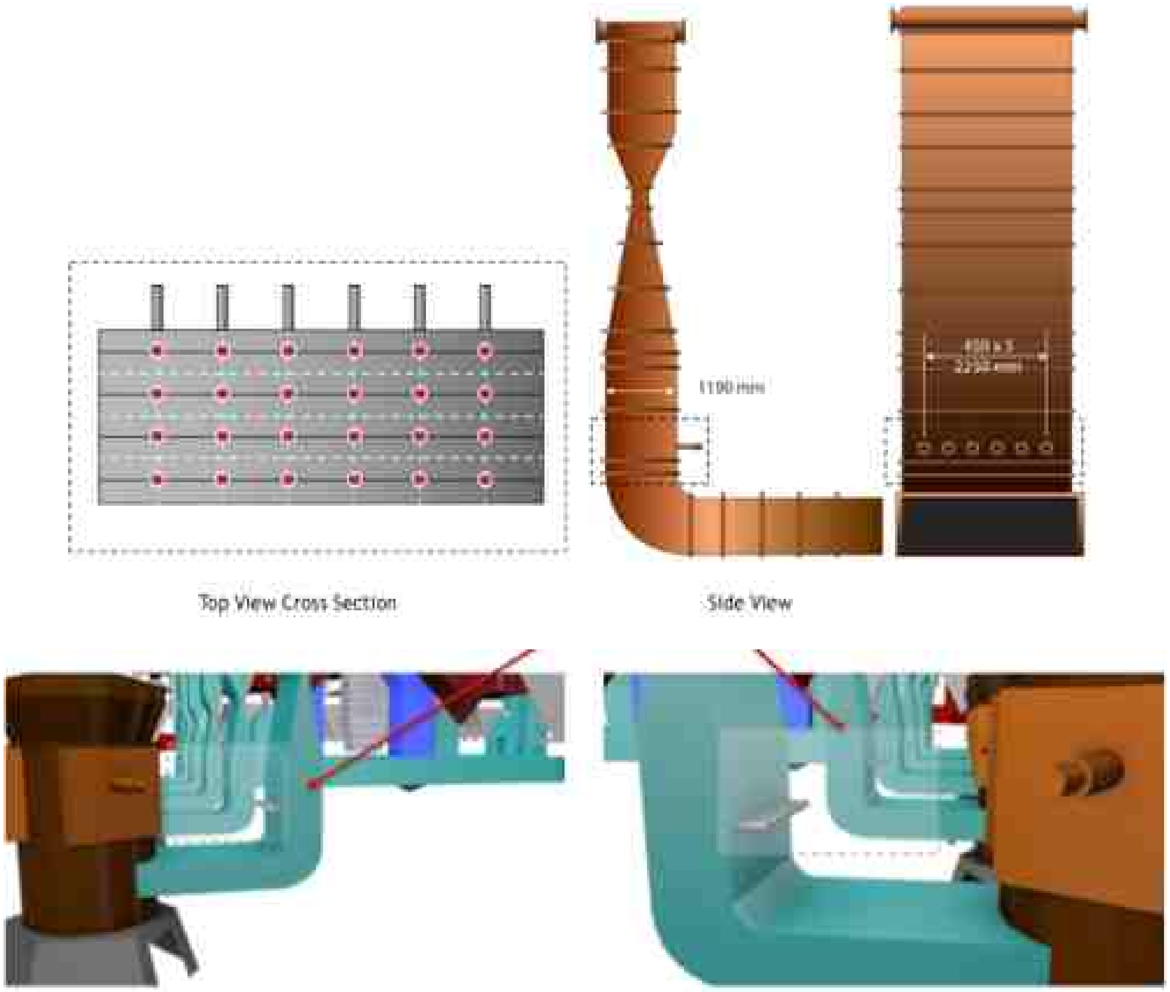


Figure 6-18: Typical 600 MW Supercritical Unit Total Airflow Measuring Element with Representative Testing Location for Calibration



- o High primary airflow negatively impacts milling systems, burner performance and furnace residence time. However, the additional tempering airflow also allows cold air to by-pass the air preheater(s), and thus impacting X ratio.

Figure 6-19: Typical 600 MW Supercritical Unit – Primary Air Flow Calibration



- o Combustion airflow and fuel flow must be balanced within acceptable standards; fuel flow should be controlled in parallel with the airflow.
- o Operating with too low excess air can result in high gas temperatures, excessive slagging, coal-ash corrosion and overheated tube circuits. Considering this, combustion airflow supplied to the boiler should be measured, controlled and validated to serve as an "online" indication for validation of excess air settings and/or air infiltration.

Figure 6-20: Photograph - Primary Airflow Calibrations

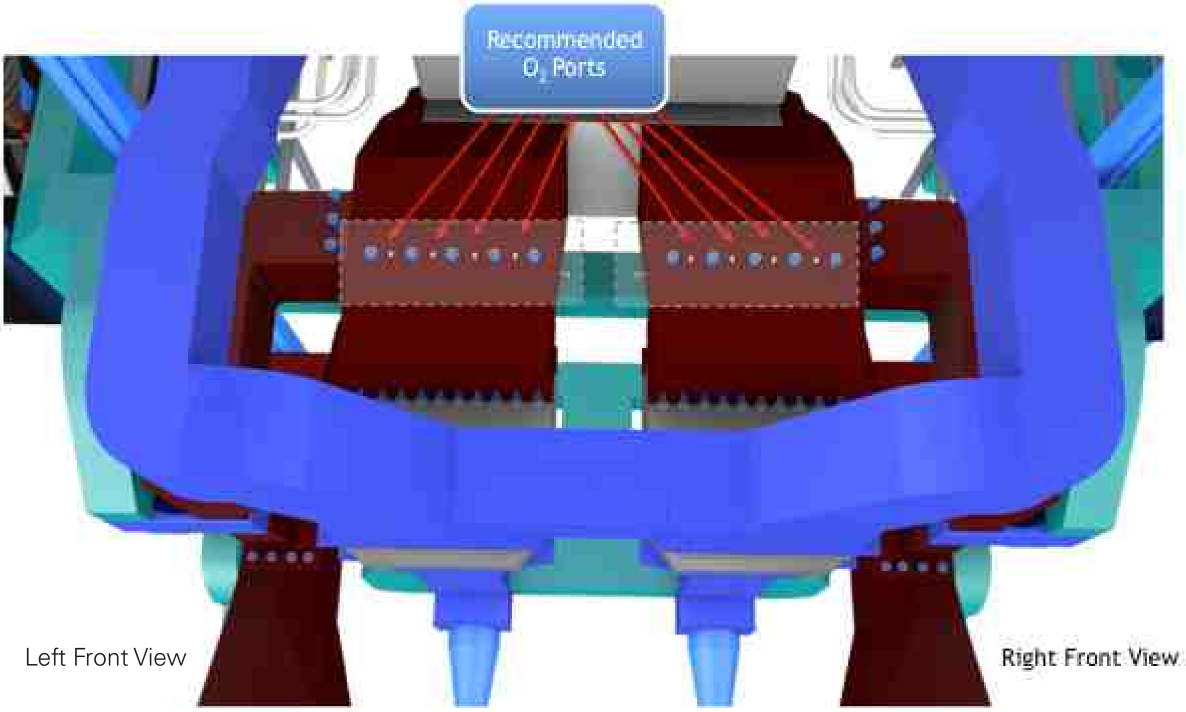
9. Furnace exit atmosphere must be oxidizing

- This can be validated by measuring and metering furnace stoichiometry with a temporary or permanently measured water-cooled HVT probe (as previously noted). See Figure 6-21.

Figure 6-21: Photograph of HVT Testing

- Validation by flue gas measurement at the furnace exit
- Ensure no point at the furnace exit is less than 2 percent oxygen
- Air/fuel ratio, calibration, measurement, staging, equalization and flow distribution is critical
- Verify economizer outlet oxygen probes accuracy and representation

Figure 6-22: Typical 600 MW Supercritical Unit – Location of Excess O_2 Probes



10. Fly ash and Bottom Ash Unburned Carbon

- Elevated fly ash “LOI” (Loss on Ignition) is an indication that combustion and available residence time is not optimized in the furnace.
- When combustion in the burner belt is “non-optimal” and combustion incomplete at the furnace exit, active combustion is still in progress. This often results in elevated flue gas temperatures that can result in overheated tube circuits, increased de-superheating spray flows, slagging and fouling.
- Monitoring fly ash and bottom ash carbon content and particle sizing via representative sampling should be completed and tested daily.

11. Mill Performance

Proper milling system practices can often result in immediate reduction in slagging propensity and the realization of several ancillary performance dividends. For supercritical boilers, temperature control and distribution with a "once through" unit is particularly important. The important milling system variables that must be addressed include the following:

- Mill outlet temperature control
- Mill horsepower per ton control
- Substandard coal fineness negatively impacts air-fuel distribution and non-optimal utilization of furnace residence time. Solid fuel particle sizing should be optimal; ideally, particle sizing of coal fineness should be >75 percent passing through a 200 mesh screen and >99 percent passing a 50 mesh screen [4].

Figure 6-23: Photograph - Coal Fineness Testing

- Fuel Line Balance and Distribution
  - Clean Air Balance should be kept within 2 percent
  - Dirty Air Balance should be kept within 5 percent
  - Fuel Balance should be kept within 10 percent
  - Air-fuel ratios controlled and optimum

- Coal rejects represent a heat loss. However, the common fix (online) is to elevate tempering airflow, which can negatively impact air-fuel ratios, combustion and Air preheater X-Ratios.

Figure 6-24: Typical 600 MW Supercritical Unit – Milling System

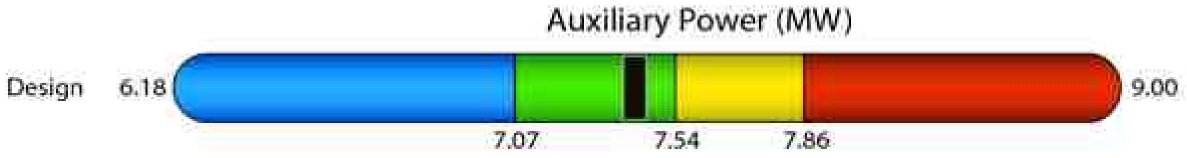
12. Auxiliary power consumption

- Increases in auxiliary power consumption can result from excessive clearances on the fans, air preheaters, air in-leakage, slagging, fouling or elevated air and gas flow rates.

- Air and flue gas dampers must be controlled for both wind box and flue gas pressure control.

- Managing auxiliary power is important. Thus, keeping a target and doing periodic auxiliary power (and water consumption) audits are recommended, as shown in Figure 6-25.

Figure 6-25: Auxiliary Power Consumption Tracking



13. All Controls and instrumentation functional checked, tuned and optimal. This includes utilizing online heat rate monitoring and pattern recognition of key performance indicators.

  - Trends such as gas temperatures, combustion airflow rates, mill horsepower per ton, de-superheating spray flows, etc. can be leading indicators of performance, assuming all equipment are functional checked for feedback accuracy.

Summary of Potential Boiler Losses

Boiler efficiency is calculated by subtracting losses from 100 percent. Every unit is assumed to start with 100 percent efficiency and then this number decreases as each loss is added [2,5].

The losses associated with boiler efficiency are:

- Losses due to CO in the flue gas
- Losses due to unburned combustibles
- Dry gas loss
- Loss due to moisture in the fuel
- Loss due to hydrogen in the fuel
- Loss due to air infiltration
- Loss due to moisture in the air
- Losses due to sensible heat in the fly ash and bottom ash
- Radiation and convection losses.

Loss due to Unburned Combustible (LOI):

Carbon loss is due to unburned carbon in fly ash and bottom ash.

Factors influencing the carbon in ash or carbon losses include:

- Coal type
- Coal quality (i.e., volatile matter)
- Ash quantity
- Boiler Design (heat release/furnace volume)
- Available residence time for combustion
- Mill and Burner Performance
  - Particle Sizing
  - Burner Distribution
  - Mechanical Condition / Settings
- Excess air/Distribution

In order to establish the losses due to unburned carbon, the collection of representative samples of fly ash and bottom ash are important.

Most of the time, not all of the combustible material is burned before leaving the furnace. This combustible material left unburned is usually carbon. The level of how much is left unburned is referred to as LOI (Loss on Ignition) or UBC (Unburned Carbon). This is considered a loss because not all of the chemical potential was used during the burning process. Therefore a lab must analyze an ash sample to determine how much carbon is remaining. The remaining percentage can then be compared to the initial percentage in the fuel to determine the loss in efficiency. The analysis should be completed in accordance with ASTM method D6316-04. The ash is evaluated in two parts. The first part is the fly ash sample taken using the fly ash probe. The second source is the bottom ash taken from the ash hopper. Because bottom ash samples are often hard to gather or analyze, samples are not often collected to evaluate ash carbon content. Thus, it is a best practice to have process and procedure in place for periodically checking bottom ash carbon content.

Fly ash samples should preferably be collected at the air preheater (APH) outlet with a representative insitu “near isokinetic” or “isokinetic” sampler. In boiler performance optimization, it is valuable to know the amount of unburned carbon in the fly ash. This is especially true when firing high ash concentration fuels such as those fired in India.

It is also imperative to ensure that the hoppers are maintained without choking.

Dry Gas Losses

The dry gas loss represents the largest single penalty to efficiency. Basically this is a penalty based on the heat being released to the atmosphere that the boiler cannot make use of. However, this also includes a few smaller considerations as well. To be perfectly efficient, the gas leaving the unit should be at the same temperature as the air entering. Any increase in gas outlet temperature over the air inlet temperature contributes to the loss.

The exit temperature measured is corrected to represent the temperature of the outlet flue gas if there were no air in-leakage through the air preheater (ASME PTC-4). This step should be taken further to account for any air in-leakage that may occur between the furnace exit and the air preheater inlet. Once the air in-leakage is calculated, the outlet temperature can be corrected to indicate what the temperature would be if there were no leakage.

The exit gas temperatures can be influenced by combustion and controlled through heat recovery within the boiler, superheater, reheater, economizer and air preheater performance. Variables that influence dry gas losses include:

- Combustion performance
    - o Air-fuel distribution

- Excess air settings
- Air bypassing the air preheater (i.e. excessive tempering airflow, boiler air in-leakage)

Excess Air

Excess air is the extra air supplied to the burner beyond the air required for complete combustion. Excess air is supplied to the burner because a boiler firing without sufficient air or "fuel rich" is operating in a potentially dangerous condition. Therefore, excess air is supplied to the burner to provide a safety factor above the actual air required for combustion.

However, excess air takes away energy released from combustion, thus taking away potential energy for heat transfer within the boiler. In this way, excess air reduces boiler efficiency. Typically, a quality and well maintained burner design allows for firing at minimum excess air levels of around 15 percent (3 percent as O_2) at full loads. O_2 represents percent oxygen in the flue gas. Excess air is measured by sampling the O_2 in the flue gas. If 15 percent excess air exists, the oxygen analyzer would measure the O_2 in the excess air and show a 3 percent measurement. Seasonal changes in temperature and barometric pressure can cause the excess air in a boiler to fluctuate 5-10 percent (if the fans are limited due to air in-leakage). Furthermore, firing at low excess air levels can result in high CO and boiler slag propensity. The fact is, even burners theoretically capable of running at less than 15 percent excess air levels rarely are left at these settings in actual practice. A realistic excess air level for a boiler in operation is 15 percent if an appropriate safety factor is to be maintained.

When reviewing an efficiency guarantee or calculation, the excess air levels must be checked. If 15 percent excess air is being used to calculate the efficiency, the burner should be of a very high quality design with repeatable damper and linkage features. Without these features, boiler will not be operating at the low excess air values being used for the calculation, at least not for long. If less than 15 percent excess air is being used for the calculation this will bias the efficiency calculations.

Loss Due to Moisture in the Fuel

Residual heat in any water vapor in the flue gas that came originally from the coal must also be counted as a loss.

Loss Due to Hydrogen in the Fuel

During the combustion of the fuel, hydrogen molecules combine with oxygen to create water vapor. This heated water vapor at the outlet must be addressed in a similar manner to existing water in the fuel.

Loss Due to Carbon Monoxide (CO) in Flue Gas

When the carbon in the fuel is not burned completely, some of that incomplete combustion is in the form of carbon monoxide. To completely burn the carbon and remove all the available energy, carbon needs to be converted into CO_2. Therefore any CO in the flue gas represents energy that was not fully utilized.

Ambient Temperature

Ambient temperature can have a significant effect on boiler efficiency and sometimes can result in seasonal changes that impact efficiency by one percent or more.

Radiation and Convection losses

Radiation and convection losses represent the heat losses radiating from the boiler vessel. Boilers are insulated to minimize these losses. However, every boiler has radiation and convection losses. Radiation and convection losses also are a function of air velocity across the boiler. A typical boiler room does not have high wind velocities. Boilers operating outside, however, will have higher radiation and convection losses.

Note*: Air in-leakage between the furnace exit and the boiler exit is typically not accounted for in the performance test codes (PTC) although it represents a real loss and has many negative impacts on combustion, boiler performance, emissions and reliability. The major impact from air in-leakage in this location is due to altered operational characteristics due to an inaccurate O_2 reading at the economizer. The standardized method for calculating these losses are detailed in the ASME PTC- 4 code.

Before performing a boiler efficiency test, the following control room and/or local indications should be calibrated and accurate.

- Steam flow
- Feed water flow – which can sometimes be used to substitute steam flow indication for efficiency calculations
- Barometric Pressure
- Gross generation (MW)
- Fuel Flow

While boiler efficiency is just the “fire-side” efficiency, heat rate is a relative efficiency that combines both the boiler and turbine efficiencies for an overall unit efficiency. Therefore, “main-steam-side” related measurements are also needed for calculating the plant heat rate, while impacting gross turbine cycle heat rate performance. The following are critical when calculating heat rate or spray flow penalties (similar to efficiency calculations).

- Superheat and Reheat spray flow
- Super-heater inlet and outlet temperatures

- Super-heater inlet an outlet pressures
- Re-heater inlet and outlet temperatures
- Re-heater inlet and outlet pressures
- Primary Airflow
- Secondary Airflow

The following "steam-side" related items have a major impact on unit heat rate. Therefore these items should be checked and/or calibrated prior to any efficiency testing.

- Condenser vacuum
- Feed water heater
  - Inlet and outlet temperatures
  - Inlet and outlet pressures
  - Drains - Need to be verified closed and not leaking
  - Level transmitters
- Heater levels normal
- Steam purity

Before any calculations can be run though, the representative data needs to be collected through testing and analysis. The important sampling locations are:

- Furnace Exit
- Air Preheater Inlet (air and gas side)
- Air Preheater Outlet (air and gas side)
- Fuel Feeder Output
- Fuel Lines

Representative samples for analyses need to be taken of the:

- Raw coal (ultimate/proximate analysis)
- Fly ash and bottom ash

From a performance standpoint, there are many readings that need to be measured, including temperature, CO, and NO_x. But for efficiency calculations, the most important measurement is the oxygen content of the flue gas. Specifically, by comparing the oxygen content at the furnace exit to the oxygen levels further downstream, the air in-leakage can be determined. The best equipment to measure these variables with is a water-cooled High Velocity Thermocouple (HVT) probe. While the name describes the method for how temperature is measured, the important part is that it is water-cooled which allows flue gas samples to be taken far into the furnace. Then, for the traditional code testing (which assumes there is no boiler air in-leakage), sampling of flue gas is conducted at the air preheater inlet and outlet.

Air Preheater Inlet and Outlet

Oxygen levels and temperatures need to be recorded both at the air preheater inlet and outlet. Per the performance test codes, the proper way to measure the gas constituents at these locations is by using a multipoint probe grid. A semi-permanent set of multipoint sampling probes that utilize multiple sampling tubes per probe should be installed in a representative grid as shown in Figures 6-26 and 6-27 respectively.

Figure 6-26: Multi-Point Sampling Probes

The probes below are located in between and outside of the recommended and permanent excess oxygen probes.

Figure 6-27: Typical 600 MW Supercritical Unit - Representative Gas Sampling

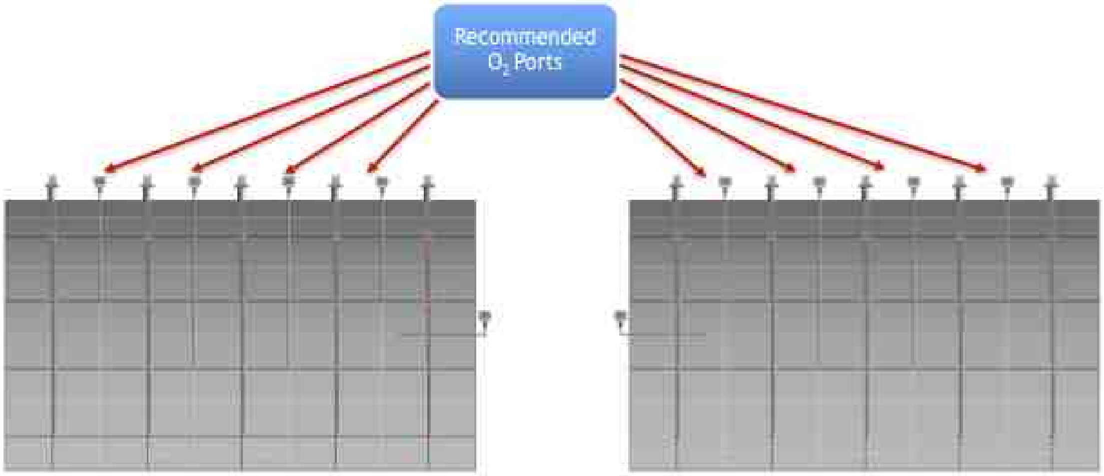
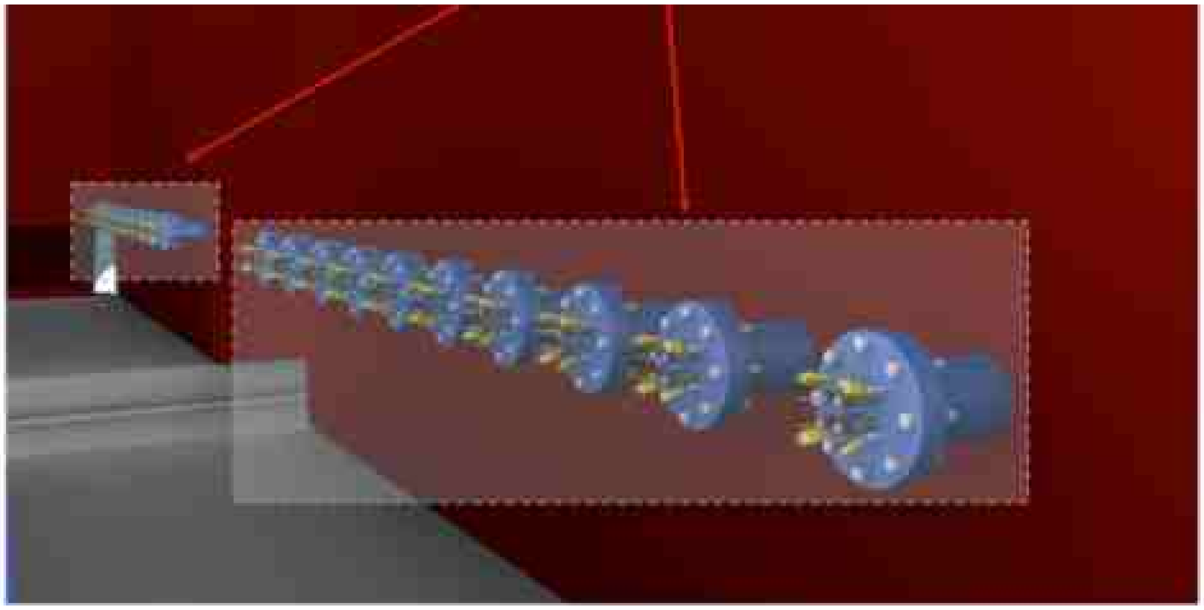


Figure 6-28: Typical 600 MW Supercritical Unit: Representative Flue Gas Sampling Ports



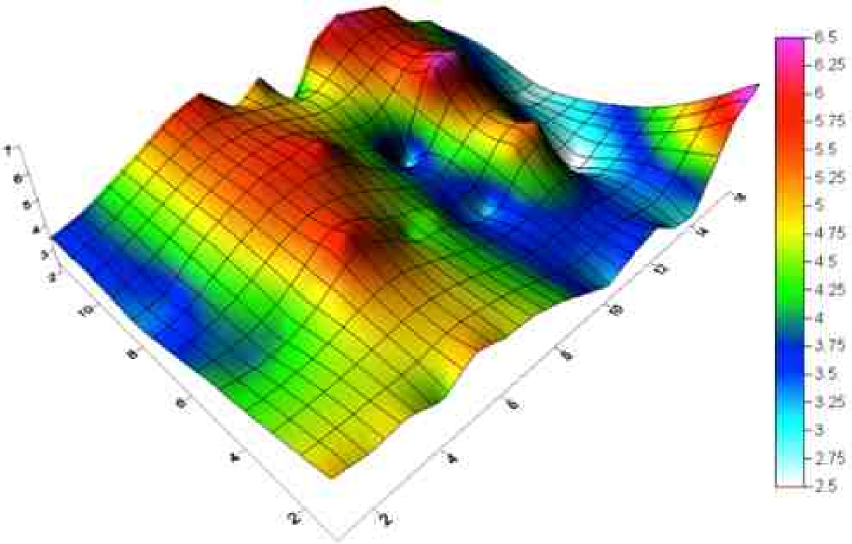
Each of the individual sampling tubes as shown in Figure 6-29 is then connected via flexible tubing to a bubbler. An aspirator then pulls suction on one or all of the sampling tubes at the same time. The flue gas is then mixed in the water before bubbling out as an individual or composite average of the duct. This flue gas is then pulled through a gas conditioner and analyzer to measure the gas constituents. So instead of doing multiple individual traverses, the average gas make-up of the flue gas can be determined at once. However, the temperature at each point is taken separately.

Thermocouples are usually placed on the multipoint probes at intervals the same length as the sampling tubes. These temperatures should be evaluated individually and then averaged together to get a duct average gas temperature.

Figure 6-29: Photograph - Multi-Point Sampling Probes

This same process is completed for both the air preheater inlet and outlet. The purpose for doing so is to evaluate how much heat is leaving the unit that was not used as well as how much air leaks into the flue gas when passing through the air preheater. The key is to ensure that a representative evaluation is completed as shown in Figure 6-30. Sometimes additional excess oxygen probes are required to get a “true' average of the excess oxygen. If only one or two sampling probes are installed, this can result in a biased sample suggesting an artificially high (or low) reading.

Figure 6-30: Example of an Actual Boiler Outlet Oxygen Profile



Particle Sizing of Fly Ash

After a sample is collected, a portion of the ash should be sieved through a 200 mesh screen, and the particles passing through are burned and analyzed. This gives an indication whether the LOI is related to coal fineness or furnace performance. After representative fly ash samples are collected during test conditions, the samples should be weighed and sieved through a 200 Standard U.S. sieve with a "Ro-Tap". The coarse particles remaining on the 200mesh sieve represent poor fineness, therefore causing a higher LOI reading. If the fine particles which pass through a 200 mesh sieve have a high concentration of LOI, there may be a problem with low oxygen in the furnace, poor mixing of air and fuel, fuel distribution, primary air, etc.

After collection, fly ash composite and fine particle LOI should be determined. Composite LOI is determined by traditional analysis. Fine particle LOI is determined by sieving sample through a 200 mesh screen, as shown in Figure 6-31. Carbon analysis or Loss on Ignition analysis is performed on the residue that passes and does not pass 200 Mesh.

The LOI of ash which passed 200 mesh (fine ash particles) should be less than 2 percent (bituminous coal) or less than 0.5 percent (sub-bituminous). Fine particle LOI is attributable to insufficient burner mixing or an oxygen starved furnace. It is a common misconception to blame high fine particle LOI on coal fineness. Coarse particle/ash residue which does not pass 200 mesh LOI can be reduced by improving mill fineness. However, fine particle LOI is typically unchanged by mill fineness.

Figure 6-31: Flyash Particle Sizing and Analysis

Additional Efficiency Considerations

In addition to the losses noted previously, there are other losses that are either un-measurable or agreed upon at an established or set loss (typically minor) for simplicity.

Additional Parameters

Additional items required to calculate boiler efficiency include the remaining items

- Steam flow
- Barometric pressure
- Ambient air temperature
- Ambient wet bulb temperature – measured by with a handheld psychrometer as shown in Figure 6-32.

Figure 6-32: Handheld Psychrometer

6.3 COLLECTING REPRESENTATIVE RAW COAL SAMPLES FOR ANALYSES

Efficiency is based on how much energy is recovered from the chemical energy in the fuel. To determine how much potential chemical energy is contained within the fuel, the fuel must be sent to a lab to analyze its chemical structure of the fuel. This set of tests is called an ultimate analysis.

An ultimate analysis reveals the percentage of elements that are contained in the fuel:

- Moisture
- Carbon
- Oxygen
- Hydrogen
- Sulfur
- Nitrogen
- Ash

In addition, the gross calorific value (GCV), also called the higher heating value (HHV) is the heat energy released from the coal when burned. When specified, some labs will be able to determine how much of other trace elements make up the fuel composition.

Coal samples should be collected and analyzed daily and must be collected during a performance test. The samples must be sealed air tight as well to prevent any moisture evaporation. The analysis should be performed in accordance with ASTM method D3176-89. It is also suggested for the plant site to collect daily proximate coal analysis and representative daily samples of the fly ash and bottom ash for unburned carbon analysis.

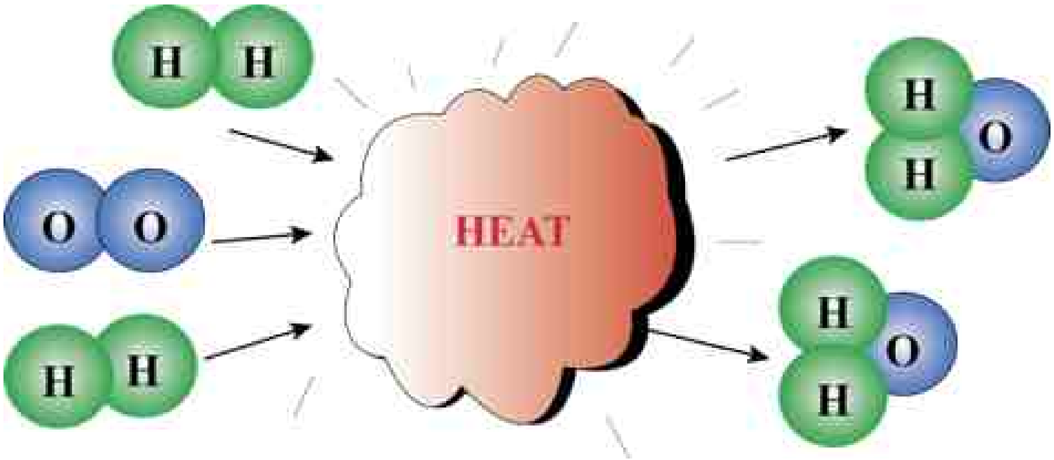
Fuel Feed Quality and Size Should be Consistent

Fuel feed to the mills should be smooth, measured and controlled. A consistent raw coal sizing of less than 25 mm (1") to the mills is recommended. This helps reduce the amount of coal rejects that spill into the pyrite hoppers as well as provide smoother mill operation during load changes [4, 6, 7].

Fuels can also have a dramatic effect on efficiency. For example, the higher the hydrogen content, the more water vapor is formed during combustion. This water vapor uses energy as it changes phase in the combustion process. Higher water vapor losses when firing the fuel result in lower efficiency. As the fuel is atomized and burning begins, the first fuel constituent to completely combust is the light ends or hydrogen. Remaining after the hydrogen combusts is the devolatilized carbon char.

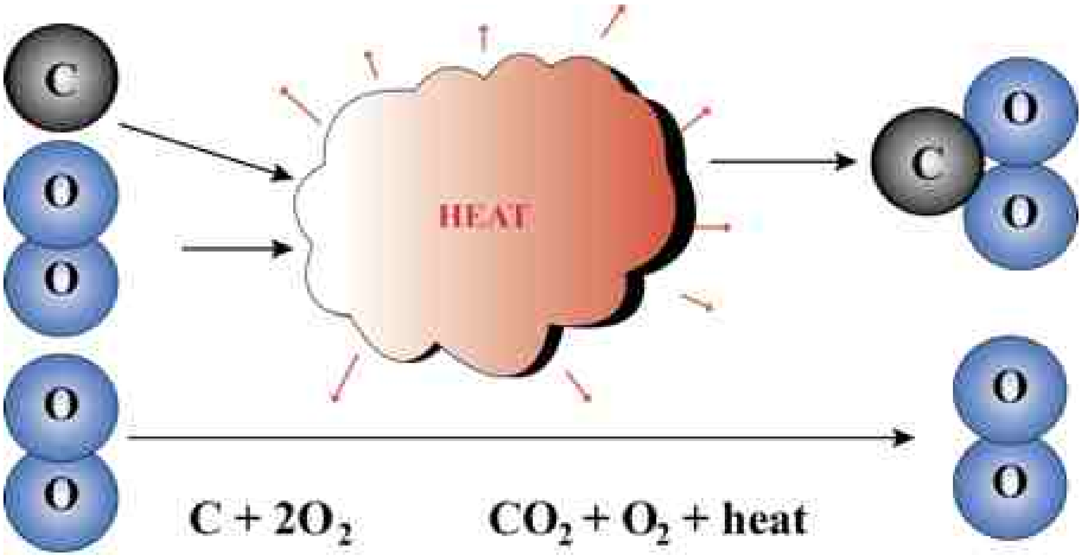
For example, the complete combustion of hydrogen, with adequate diatomic molecules of oxygen in the air, will result in water vapor and heat release. 4kg (9lbs) of water result from the combustion of each 1kg of hydrogen.

Figure 6-33: Combustion of Hydrogen Illustration



Excess air results in free oxygen (excess oxygen) and/or excess air (including Nitrogen) to simply move through the furnace causing excessive "dry gas losses." Simply stated, this is the heating of excess air to the stack temperature and wasting of heat energy to heat air that was not necessary for combustion.

Figure 6-34: Formation of CO_2 and Excess Air Illustration



Each fuel is comprised of varying elements such as carbon, hydrogen, oxygen, and sulfur. Smaller amounts of other elements such as phosphorous, nitrogen, mercury, silicone, calcium and iron also are possible constituents in the fuels. These variables not only influence combustion, but also the byproducts of combustion such as slagging and ash particle resistivity.

All fossil fuels are a mix of large organic compounds and during the combustion process these compounds break down. The two primary elements that contribute to the heat release of the fuel are carbon and hydrogen. When these elements oxidize (combine with oxygen) the carbon creates carbon dioxide (CO_2) and the hydrogen creates water (H_2O).

$$C + H + O_2 \quad N_2 \qquad\qquad CO_2 + H_2O + N_2$$

$$\text{Fuel} + \text{Air} \quad \text{Combustion} \quad CO_2 \quad \text{Water} + N_2 \quad \text{Heat}$$

Coal Blending Best Practices

Advancements in coal handling systems present an opportunity for coal fired power plants to match coal quality to the desired operational conditions. This can result in improved plant performance, fuel flexibility ,and environmental output by managing not only coal quality standards, but also sorbent and other chemicals that may be required to meet air pollution regulations.

During a recent USAID utility exchange program, surveys of the plants and major utilities assessed suggested that blending is commonly used for two primary reasons. First of all, coal fired power plants want to fire lower cost fuels and secondly, the plants in the U S .must meet stringent SO_2 emission limits. As a fundamental approach to coal blending, one of the key factors required for a successful coal blending program is to ensure that any blend provides adequate fuel heat content ,so the unit is not de-rated because of limited mill capacity and/or the required heat input to achieve full load operation. The firing of a particular coal or coal blend in the boiler can also have varying impacts on the plant emissions and duty placed on the air pollution control equipment. For example, the performance of an electrostatic precipitator is largely influenced by coal quality, the volume of ash, flue gas chemistry and the ash resistivity which is influenced by not only the flue gas chemistry, but also the particle sizing and mineral matter in the ash. In conjunction with coal handling, many of the U S .plants are also managing other chemicals and sorbents such as ammonia, SO_3, limestone, hydrated lime, magnesium hydroxide, calcium carbonate and activated carbon for the new utility mercury and air toxic standards known as Utility Mercury and Air Toxic Standards (UMATS). Considering this, blending silos, stacking, stocking ,and automated conveying systems are commonly being used to blend coal for compliance requirements and achieving homogenous blends for consistency of coal quality.

In India, coal blending is commonly used to achieve the heat input required at the boiler. Blending can be accomplished at a preparation plant offsite or onsite. With large stations, the stacking method with an automated system is commonly used. It is also very important to understand the coal ash composition; ash content of blended coals can have a significant influence on combustion and overall plant performance with varying changes with coal and ash chemistry. For example, the percentage of sulfur, sodium ,and potassium in the fuel can have a large impact on chemical activity of the ash deposits.

Coal quality variables that need to be taken into consideration include:

- Heating Content
- Moisture
- Hardgrove Grindability Index (HGI)
- Impact on mill capacity
- Reactivity
- Ash content; ash mineral analysis
- Slagging and fouling characteristics
- Impact on combustion efficiency
- Impact on air emissions (including trace elements)
- Nitrogen, carbon to volatile ratio, sulfur, etc.

One practice being used in the U.S. is to evaluate blended coal characteristics through computational evaluation or modeling. By doing this prior to stacking, stockpiling or reclaiming blended coal, this can help the plant operators better understand the varying aspects of a blend's behavior and its effect on power station components from the stockpile to the stack. Even if blended coal closely resembles the design coal of the boiler, the blend may produce eutectics and will not necessarily provide the same performance as the design fuel due to the blending of mineral ash constituents or other inorganic particles during combustion. The amount of ash in the coal, its behavior, impact of slag propensity and overall thermal performance must be addressed. Also the operational strategy to manage the emissivity, reflectivity and variations with heat transfer due to such accumulations [1, 8].

Because of the complexity of the combustion process and the number of variables involved, it is sometimes difficult to extrapolate the results from a model or laboratory. Thus, after the initial due diligence is completed with modeling of coal characteristics, plants often conduct pilot tests or "test burns" with varying blends, prior to certifying or accepting a longer term contract. Also, other factors such as material handling, sizing, volatility, dust suppression, spontaneous combustion and fire protection systems are factors that need to be addressed.

As previously noted, it's important to understand coal quality. One way to manage the coal resources is to utilize coal analyzers for "real-time" analysis. A review of the current technologies and type of analyzers being used are described in Table 6-2.

Table 6-2: Coal Analyzer Technologies (Woodward Consulting, May 2013) [9]

Parameter(s) to be Analyzed	Technologies in Use	Major Suppliers	Typical Accuracy (one hour, one sigma)
Most Elements (Sulfur, ash constituents, N, H, Cl)	Prompt Gamma Neutron Activation Analysis (PGNAA)	Thermo Fisher Scientific, Sabia, Scantech, PANalytical, Scanmin	Sulfur—0.04% Ash—0.4% Chlorine—0.01% Hydrogen—0.2% SiO2, Al2O3, CaO —1% relative K2O, TiO2, Fe2O3 —0.2-0.5%
	Laser Induced Breakdown Spectroscopy (LIBS)	Progression	Generally comparable to those in cell above; except able to measure Na_2O and sometimes MgO
Carbon and Oxygen	Fast Neutron Activation	PANalytical, Scanmin	0.75% - 1%
Moisture	Microwave	RTI, Scantech, Berthold	In sample stream analyzer (Thermo CQM) 0.5%; otherwise, uncorrelated
	Magnetic Resonance	Progression	0.3% - 0.5%
Calorific Value	Usually MAF Dilution	All of them	0.5% - 1.5% relative

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Moisture	Microwave	RTI, Scantech, Berthold	In sample stream analyzer (Thermo CQM) 0.5%; otherwise, uncorrelated
	Magnetic Resonance	Progression	0.3% - 0.5%
Calorific Value	Usually MAF Dilution	All of them	0.5% - 1.5% relative

A summary of the nuclear coal analyzer technology suppliers and types that was provided by Woodward Consulting (May 2013) is given in Table 6-3 [9] .

Table 6-3: Nuclear Analyzer Suppliers

Analyzer Type	Suppliers	Remarks
Sample Stream	Thermo Fisher Scientific (CQM) Progression (Titan CCA)	Best accuracy, most expensive. CQM flow capacity 40tph, Titan CCA flow capacity 120lbs/hr
Full Flow (mounted around the conveyor)	Thermo Fisher Scientific(ECA) Sabia (X1) Scantech (Coalscan 9500X) Scanmin (NITA II)	Accuracies worsen on conveyors above 60 inches in width, and on top sizes greater than 2 inches(100mm)

6.4 MILLING SYSTEMS PERFORMANCE

Milling systems are responsible for supplying pulverized coal to the boiler and have three primary responsibilities [10] .

The three main functions of a mill include:

1. Pulverize coal particles to ideally less than 60 microns (average size)
2. Evaporate moisture (using a mixture of hot and tempering airflow)
3. Distribute pulverized coal to the fuel lines and burners using primary airflow as the transport medium.

Raw coal is typically apportioned to the mills by usage of coal feeders and then transported and carried through the milling system with primary airflow. Coal is then crushed by the grinding elements. Then, once the fuel is fine enough, the primary air helps to dry and sweep the coal out of the mill into a classifier where the coarse and fine particles are separated. Coarse particles are returned to the mill for continued grinding. Fine particles are separated out and distributed to the individual fuel lines. Considering this, measuring mill and fuel line performance is essential for combustion optimization on any PC fired unit. Controlling air-fuel ratios on a milling system is important for many reasons. For example, higher than desirable air-fuel ratios sweep coal particles from the mill faster than necessary, limiting the residence time for grinding and thus decreasing coal fineness and typically exceeding acceptable air-fuel distribution tolerances.

The minimum airflow setting should be determined by what is necessary to achieve the required velocities for the respective transport pipes. Sometimes burners have a larger burner nozzle than the fuel pipes. In those cases, the minimum airflow velocity needs to be based on the larger size. In addition, with the minimum airflow set point, it is imperative that the velocity be sufficient to keep coal from rejecting, but also allow pyrites to escape. Coal rejecting below the grinding race is exposed to excess oxygen and temperature that can lead to fires and or explosions. To prevent this, operations may be required to increase primary airflow to increase this velocity if coal rejects do occur.

Sometimes primary airflow is biased upward to improve load response, but not realizing the negative impact on fuel fineness, flame propagation, component erosion and overall combustion performance. Hot and cold airflow is regulated into the mill to achieve a mill outlet temperature set point. This temperature makes sure that the moisture in the coal does not lead to fuel line plugging. Depending on the moisture content of the fuel, the hot and cold air dampers will open or close to maintain this outlet temperature. In cases of extremely high moisture fuels, the hot air damper can be fully open while the cold air damper is fully closed. With western or sub-bituminous coals, this is very common.

To assure performance preservation with mill performance, it's ideal to have “Mill Blue-Print” for mechanical optimization as well as a “Performance Trouble-shooting” Plan available to assess performance conditions when they arise. In addition, comprehensive testing and performance evaluations must be completed to evaluate and benchmark a milling system's performance to assess both mechanical and operational performance. Some of these checks are as follows: [3, 8].

Mill Performance and Troubleshooting Checks

- Coal quality (HHV, HGI, Moisture, etc. impact mill capacity)
- Raw coal size
- Verify primary air flow is on curve
- Ensure the feeder output is correct
- Ensure Mill outlet temperature is correct
- Understand the Fuel HGI, moisture, raw coal size and their impact on capacity
- Damper controls and responsiveness
- System pressures and flow from air preheater (supply ducts and milling system)
- Mill heat balance evaluations (requires thorough study of the fuel quality, air supply and sampling at the mill discharge)
- Validation of coal fineness
- Available Motor Horsepower/Ton of coal being processed

Mill and Burner Performance Considerations

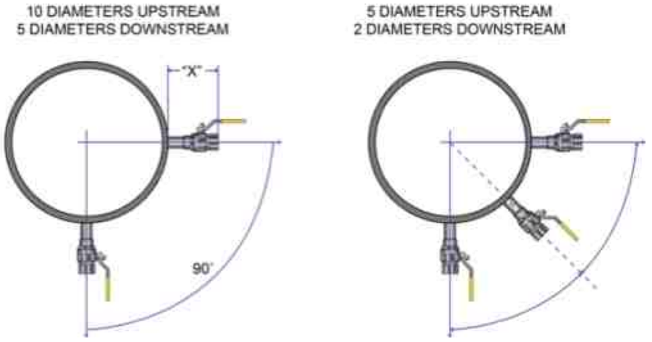
- As mill fineness is increased above design, mill capacity decreases incrementally.

- A mill becomes less tolerant under changing coal conditions and may require operations to choose capacity over performance. The changes most likely to influence milling capacity under high fineness levels are: HGI and Coal Moisture.
- Burner ignition points too close may result in burner tips causing overheating.
- Mill outlet temperatures and burner settings should be tuned according the fuel fired.
- With improved coal fineness, more rapid combustion occurs lower in the furnace region, resulting in greater water wall heat absorption, lowering furnace exit gas temperatures.
- Mill resistance will vary with performance and load capacity.
- Power consumption increases with higher moisture or lower BTU fuels.
- If mill capacity is exceeded, coal spillage through the reject hoppers may become apparent due to a deeper fuel bed and declining airflow.
- The relative humidity within the milling system varies as a function of entering moisture levels vs. the air flow rate and temperature.
- Additional recirculation within the mill due to non-optimal settings can induce accelerated wear of the mill.

6.5 FUEL LINE SAMPLING OF PULVERIZED COAL FUEL CONDUITS

With pulverized coal fired boilers, fuel line conduit test taps must be installed to facilitate insertion of testing probes for measurement of clean air and/or dirty air sampling. Ideally, coal line test taps should be located in a vertical run of piping between five and ten diameters downstream or upstream of the nearest obstruction (i.e. ,elbow, orifice plate, flange, isolation valve, etc.). Two test ports, 90° apart, per pipe are required. Clean air test ports are often installed by drilling and tapping 12.7 mm (½") N.P.T. holes through the pipe wall and inserting a threaded pipe plug (or by welding 12.7mm (½") half couplings on the pipe with a bored holes and removable pipe plugs inserted). Dirty airflow testing ports, must be equal lengths, spaced accordingly and with adequate accessibility outside of the traverse plane. See Figure 6-35 for the fuel line sampling port requirements.

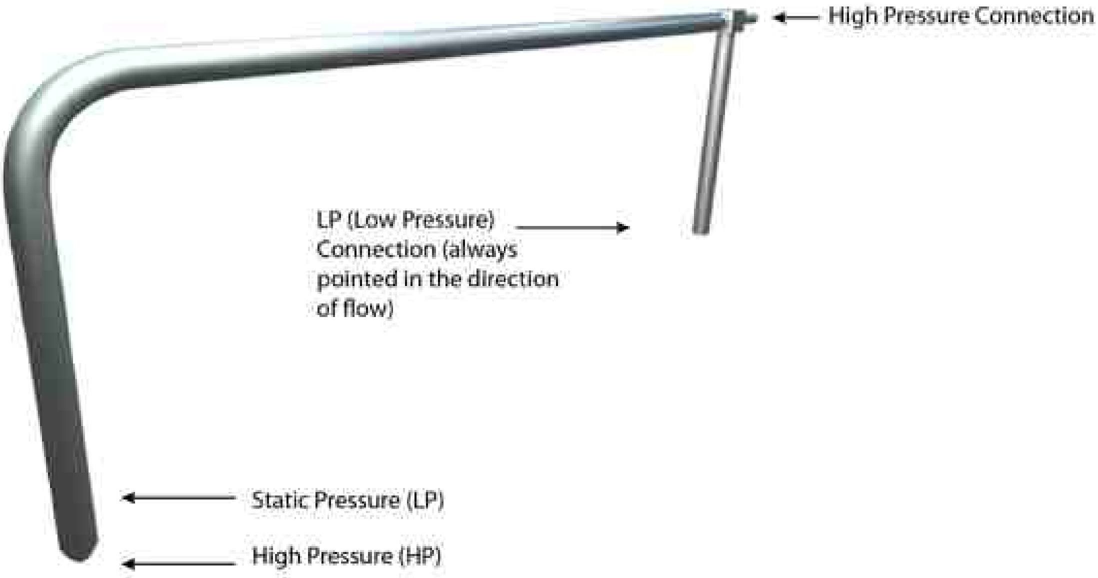
Figure 6-35: Typical Testing Port Standards for ASTM Equal Area Sampling



Clean airflow tests should be completed to ensure fuel lines are balanced within ±2 percent.

In order to measure clean airflow balance and distribution, clean air tests should be conducted on all mills and each of the associated burner lines using a standard pitot tube [8, 11] .

Figure 6-36: Diagram of a Standard Pitot Tube



During this test, airflow should be set at the minimum set-point with the mill outlet temperatures set at the normal operating temperature and with the coal feeders out of service.

Figure 6-37: Plant Engineers Conducting a Fuel Line Clean Air Test

Purpose of Clean Air Testing

- Establish similar system resistance for each burner line on a balanced airflow basis.
- Provide a correlation between fuel line “dirty air” and clean air velocities

Notes: Clean air balancing is an integral part of air to fuel ratio balancing that incorporates air as well as fuel balancing.

The minimum fuel line velocity should be maintained after optimization of primary airflow to improve flame stability at lower loads and reduced fuel line stoppages. Figure 6-38 depicts an actual performance for a clean airflow balance on a 460 MW unit with five mills and six fuel lines and burners for each mill as shown in Figure 6-39 [12] .

Figure 6-38: Fuel Line Clean Air Balance Graph for a 460 MW Unit

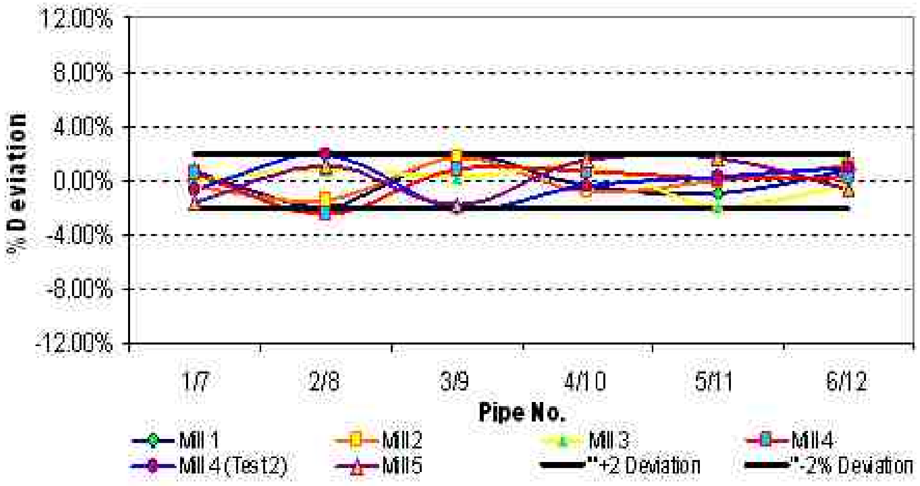
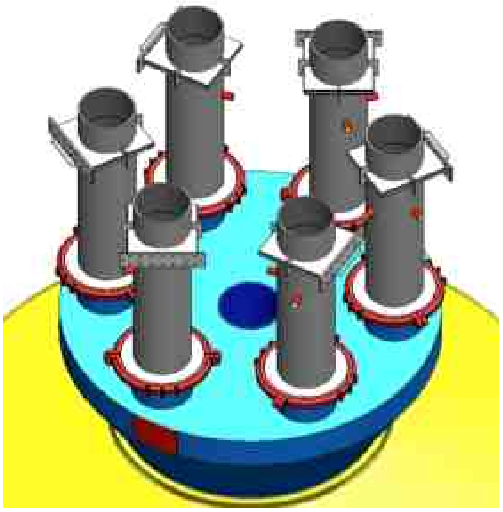


Figure 6-39: Mill Discharge Fuel Line Orifice Housings

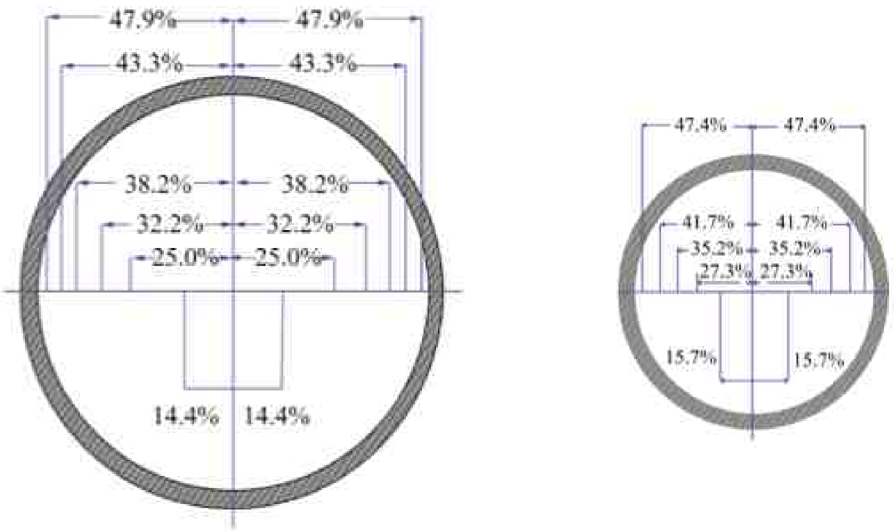


Conducting a Clean Air Test

Traverse points on the pitot tube are marked on an equal area grid in accordance to ASME Performance Test Code for traversing circular ducts as shown in Figure 6-40 [3] .

Figure 6-40: Equal Area Traverse Grid for Circular Ducts and Pipe Dimensions are "Percent of Pipe Diameters";

Note: Each Percentage is multiplied by the inside diameter of the pipe to show the sampling point.



Six Zones (305mm or larger) and five Zones (254mm - 279mm)

The following data should be recorded for each test:

- Coal pipe designation
- Individual velocity heads for each traverse point - Typically 24 or 36 points, 12 per port
- Temperature and static pressure for each pipe

Primary airflow is the transport energy for delivering fuel to the furnace. Therefore, the flow should be balanced as best as possible. If imbalances are noted, validation test and functional checks on the equipment, fuel lines, dampers, orifices and burners should be conducted to determine the root cause.

Clean Air Testing Process

1. Ensure all fuel conduits are accessible with representative sampling ports and clearly marked.

2. Set-up the equipment.
3. Conduct sampling process in the vertical fuel lines, using proper techniques and avoiding elbows or other flow disturbances.

   Note: Traverses on the fuel lines should be based on an equal area grid in accordance to ASME Performance Test Code for traversing circular ducts.
4. Usage of gauge oil manometers for precision measurement, heavy wall tubing and local functional checks prior to each test is very important.
5. The following data should be recorded for each test:
   - Fuel pipe designation
   - Individual velocity heads for each traverse point
   - Temperature and static pressure for each pipe
6. After the clean airflow sampling process is completed, the final step is to calculate and reduce the dirty air traverse data.
7. For validity testing, multiple tests with two separate test teams are recommended.
8. Results should be calculated immediately following completion of the tests and results from both teams compared. If the results deviate greater than 1 percent between each of the two sets of data, then the test should be repeated. This is done to assure repeatability, accuracy, validity and steady airflow and air temperature was attained during the test.
9. Clean air tests should be performed while maintaining a steady fuel line velocity similar to the normal operating conditions.
10. The system resistance for all fuel lines operating under "clean air" conditions from each mill must be absolutely similar and proven by Pitot traverses within ±2 percent.

Dirty Airflow Measurement and Isokinetic Coal Sampling

Measurement of dirty air and fuel mixtures going through the fuel lines is commonly known as dirty airflow testing. This is also a pre-requisite to isokinetic coal sampling where samples are extracted from coal sampling apparatus and ensure when the coal flow entering the coal sample collection nozzle is equal to the velocity of the flow within the fuel line sampled [3] .

Purpose of Isokinetic Sampling:

- Ascertain relative pipe-to-pipe fuel balance
- Quantify individual fuel line air to fuel ratios
- Quantify mill air to fuel ratio
- Quantify individual fuel line velocity and airflow
- Ascertain pipe-to-pipe airflow balance
- Quantify fuel line temperature and static pressure.
- Obtain representative fuel samples for coal fineness analysis.

Optimal Mill Performance Benchmarks:

- Pipe-to-Pipe fuel balance within 10 percent of the mean fuel flow
- Pipe-to-Pipe dirty airflow balance within 5 percent of the mean airflow
- Optimal air to fuel ratios
- Minimum fineness level: 75 percent passing 200 mesh and <0.1 percent remaining on 50 mesh
- Mill-to-Mill mass air and fuel balance within 5 percent of the mean.
- Mill outlet temperature 68°C (155°F) w/ low moisture and low to medium volatile fuels
- Minimum fuel line velocity of 1,005 Mpm (3,300 Fpm).

Performing a Dirty Air Test

Dirty air velocity and fuel sampling measurements should be at a minimum of two axes located 90° apart on a vertical run of pipe. An increased number of traverse planes may be required when the test port locations are in close proximity of a pipe bend or other flow disturbances. Test taps in horizontal runs should always be avoided. Dirty air velocities must be measured in each fuel line to establish proper sampling rate for the isokinetic sampler and to determine airflow in a solid fuel (or ash) transport pipe. With acceptable clean airflow distribution, fineness and classifier tolerances/settings, the fuel lines should ideally be balanced by "Dirty Air" test, within ±5 percent or better. Also, fuel lines should ideally have balanced fuel flow distribution within ±10 percent or better. In order to measure the dirty airflow and fuel flow distribution to each burner, isokinetic coal samples should be collected from each of the mills' respective fuel lines with the mills in service and the individual feeders in manual during the test.

The Dirty Airflow Testing Process

1. Ensure all fuel conduits are accessible with representative sampling ports and clearly marked.
2. Set-up the equipment.
3. Conduct sampling process in the vertical fuel lines, using proper techniques and avoiding elbows or other flow disturbances.

   Note: Traverses on the fuel lines should be based on an equal area grid in accordance to ASME Performance Test Code for traversing circular ducts.
4. Use of gauge oil manometers for precision measurement, heavy wall tubing and local functional checks prior to each test is very important.
5. The following data should be recorded for each test:
   a. Fuel pipe designation
   b. Individual velocity heads for each traverse point
   c. Temperature and static pressure for each pipe. After the dirty airflow sampling process is completed, the final step is to calculate and reduce the dirty air traverse data.

Isokinetic Coal Sampling Process:

1. After determination of dirty air velocity in a given fuel line, isokinetic coal samples are extracted.

2. To calculate the sampling rate of for the isokinetic sampler, the sampler orifice differential pressure is based on the dirty air velocity traverse. Then, a sampler differential is monitored by a standardized orifice and inclined manometer, if completed properly. In some cases, gauges and electronic instrumentation may be used. However, the accuracy and precision are essential.

3. During the extraction process, equal area markings and representative grid sampling is utilized to collect the samples of coal flowing through the conduits.

4. Empty the sample collected in the sample jar and filter canister into a sample bag labeled with the pipe designation, test number and date. Take care to ensure that the entire sample is emptied into the sample bag. Sample weight will be utilized to calculate fuel flow.

   After collection, the samples are placed in sealed bags, weighed and recorded on a data sheet. Then, fineness analysis is completed on each individual sample.

Optimum Mill Performance Benchmarks

- Pipe-to-pipe fuel balance within ±10 percent of the mean fuel flow.
- Pipe-to-pipe dirty airflow balance within ±5 percent of the mean airflow.
- Optimized mill air to fuel ratio.
- Minimum fineness level: greater than or equal 75 percent passing 200 mesh and less than or equal 0.1 percent remaining on 50 mesh.

- Mill-to-mill mass air and fuel balance within ±5% of the mean.

- Mill outlet temperatures optimal and based on volatility, inlet temperature limitations and considering the mills heat balance for a respective fuel.

- Minimum fuel line velocity of 1,005 meter/min. or 16.75 meter/second (or 3,300 ft./min.)

Dirty Air and Isokinetic Coal Sampling Illustrations

Figure 6-41: Temperature Measurement

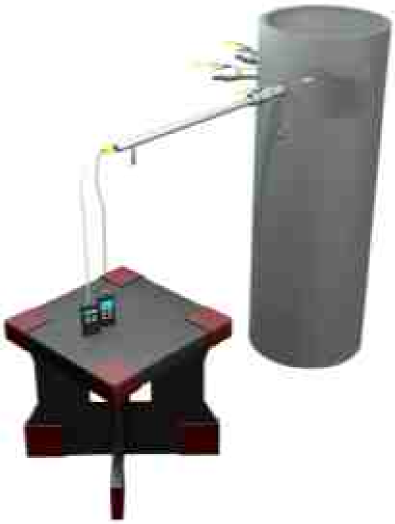


Figure 6-42: Dirty Airflow Sampling

Figure 6-43: Isokinetic Coal Sampling (via Modified ASME sampler)

Fuel line sampling can also be measured using an ISO-9931 rotor probing technique where four sampling heads are rotated 360° to extract coal samples isokinetically (via a 64 points).

Some additional tools are available for online feedback of dirty airflow and coal balance. However, considering reliability and challenges with high ash Indian coals, utilization of such instrumentation has not yet been proven as a "best practice" in Indian thermal plants.

Coal Fineness Analysis

To achieve optimal combustion, ideally, fuel line fineness should be >75 percent passing a 200 mesh screen and <0.1 percent on a 50 mesh screen (all fuel lines). Once representative coal samples are collected isokinetically, coal fineness analyses should be completed using a Ro-tap and a series of 50, 100, 140 and 200 mesh sieve sizes to validate grinding efficiency of the samples collected from each fuel line.

The plant laboratory should have a Ro-tap shaker and all necessary scales and laboratory equipment to conduct this testing. To determine the classifier outlet homogenization and the weighted coal fineness average for the entire mill, each fuel line must be analyzed separately.

Prior to conducting sieve analyses, the sample may need to be dried to ensure the sample is free of moisture (unless the fuels fired are very low moisture) and the fuel lines have adequate operating temperature to minimize moisture in the recovered pulverized coal sample. Wet or sticky coal fineness samples will induce balling and/or corrupt the "true" grinding performance of the mills.

Necessary Equipment

- Sieves: 50, 100, 140, 200
- Scale capable of weighing a total isokinetic sample (+800 grams) w/ precision of at least 0.1g
- Dryer (if necessary)
- Riffler or equivalent method for separating samples
- Compressed air or brush

If there is high moisture in the coal (>10 percent), the sample of coal needs to be dried first. This prevents the lumping together of the coal during sieving, which could result in error in the sample results. Dry the sample at 15ºC above room temperature until there is less than a 0.1 percent change in the sample weight. The dryer should allow for at least 1 – 4 air changes per minute.

If the following are met, then drying may not be required:

- Mill outlet temperature > 65°C (150F)
- Total fuel moisture is below 8 percent
- Samples are placed in plastic sealable bags immediately after sample recovery
- Sieving is done immediately after sampling
- No balling or lumping of the particles is observed during sieving

Coal Sieving Process

- Weigh out a 50 gram sample.
- The preferred method is to riffle the sample. If a riffler is not available then the sample must be rolled 100 times to ensure a representative sample is used for analysis.
- Clean the sieves. Compressed air (dry) works best.
- Weigh and record each of the sieves and the bottom pan.
- Place a 50 gram sample on the 50 mesh screen.
- Stack the sieves on the bottom pan with the 200mesh on the bottom and the 50mesh on the top. It is recommended that a 50, 100, 140 and 200 mesh are used for improved analytical evaluation with the RandR graph.
- Shake the sample through the sieves with a Ro-Tap for a minimum of 20 minutes.
- Record and weigh each of the sieves and the bottom pan.

Calculate the weight remaining on each mesh by subtracting the initial weight from the final weight for each sieve. For example:

Weight of 50 mesh screen before shaking	200 grams
Weight of 50 mesh screen after shaking	203 grams
Weight remaining on 50 mesh screen	3 grams

Calculate the percent passing through each mesh:

Weight of Test Sample W_______

Weight remaining on 50 mesh R1 (g)_______

Weight remaining on 100 mesh R2 (g)_______

Weight remaining on 140 mesh R3 (g)_______

Weight remaining on 200 mesh R4 (g)_______

Weight remaining in Pan
(Passing 200 mesh) R5 (g)_______

% Passing 50 Mesh $\frac{(W - R_1)\ x\ 100\%}{W}$

% Passing 100 Mesh $\frac{(W - (R_1 + R_2))\ x\ 100\%}{W}$

% Passing 140 Mesh $\frac{(W - (R_1 + R_2 + R_3))\ x\ 100\%}{W}$

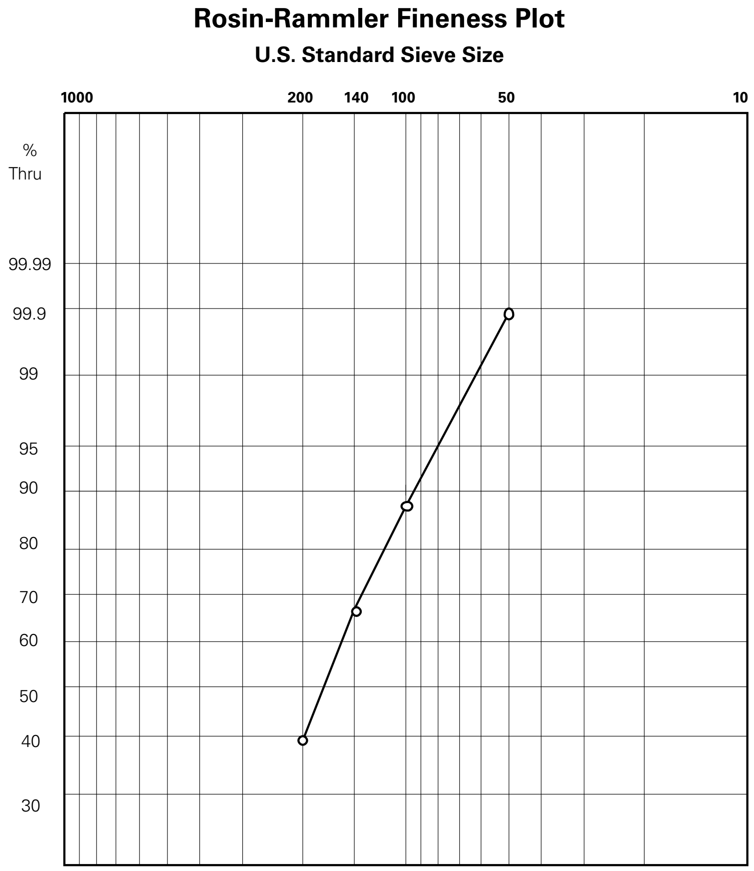
% Passing 200 Mesh $\frac{(W - (R_1 + R_2 + R_3 + R_4))\ x\ 100\%}{W}$

% Recovery $(W - (R_1 + R_2 + R_3 + R_4 + R_5))\ x\ 100$

Plotting a Rosin-Rammler Graph

Once data is collected and plotted, the points on the graph should form a straight line a as shown in figure 6-44. If the points do not form a straight line (through the 100, 140, and 200 meshes) then further investigation is needed.

Figure 6-44: Rosin-Rammler Coal Fineness Plot



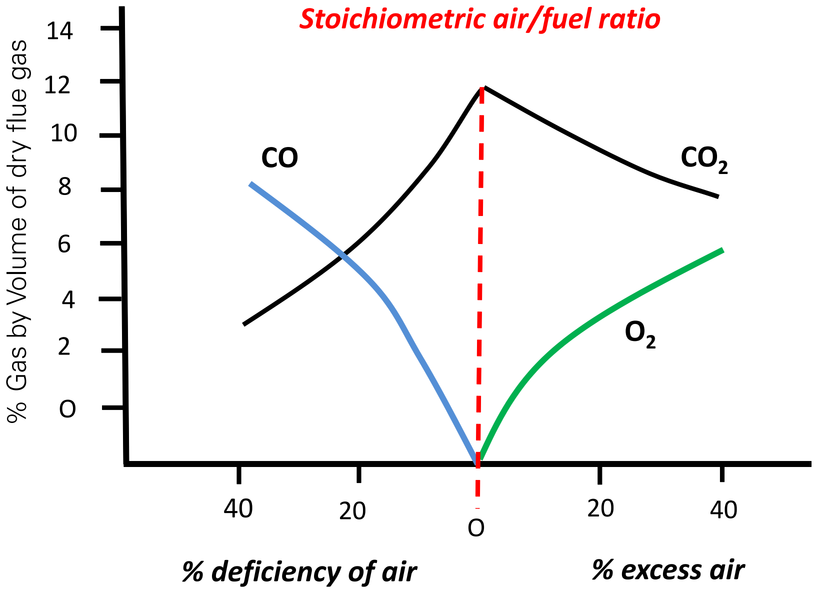
Some reasons for not having a straight line on the Rosin-Rammler curve:

- Sampling rate is non-isokinetic
- Human Error (testing error or error in calculations prior to extraction)
- Poor sample port location, which results in a non-representative sample
- Excessive moisture
- Problems with the mill, such as short-circuiting of large particles (or malfunctioning).

6.6 TOTAL AIRFLOW MEASUREMENT AND CONTROL

Stoichiometric Combustion is when the ideal combustion process in which a fuel is completely burned. If there are unburned components in the exhaust gas such as C, H_2, CO, the combustion process is incomplete [5, 12] .

Figure 6-45: Example Illustration of Excess Air vs. Total Air-Fuel Ratio



When the oxygen already in the fuel and the precise amount of air needed to complete the combustion of the carbon and hydrogen molecules in the fuel has been provided, this is what is called stoichiometric or theoretical combustion. However, air in addition to the theoretical air shown in Figure 6-45 is often required to complete combustion. This is what is called excess air. Most coal-fired boilers were originally designed for 20 percent excess air or about 3.5 percent oxygen. However, most currently operate with about 10–15 percent excess air in the furnace (assuming air in-leakage is minimal).

In simple terms, excess air is the extra air supplied to the burner because a boiler firing without sufficient air or "fuel rich" is operating in a potentially dangerous condition. Therefore, excess air provides a safety factor above the actual air required for combustion. However, excess air uses energy from combustion, thus taking away potential energy for transfer to water in the boiler. In this way, excess air reduces boiler efficiency. A solid fuel firing system and burners that are performing well will allow firing at minimum excess air levels of 15 percent (3 percent as O_2). O_2 represents percent oxygen in the flue gas. Excess air is measured by sampling the O_2 in the flue gas. If 15 percent excess air exists, the oxygen analyzer would measure the O_2 in the excess air and show a 3 percent measurement.

Seasonal changes in temperature and barometric pressure can also cause the excess air in a boiler to fluctuate by 5-10 percent. Furthermore, firing at low excess air levels can result in high CO and boiler slagging, especially with low NO_x burners or a shortage of fan capacity. The fact is, even burners theoretically capable of running at less than 15 percent excess air levels rarely are left at these settings in actual practice. A realistic excess air level for a boiler in operation is 15 percent if an appropriate safety factor is to be maintained.

Fuel Feed Quality and Size Should be Consistent

Fuel feed to the mills should be smooth, measured and controlled. A consistent raw coal sizing of less than 25 mm (1”) but ideally less than 19 mm is recommended. This helps reduce the amount of coal rejects that spill into the pyrite hoppers as well as provide smoother mill operation during load changes.

Fuels composition can also have a dramatic effect on efficiency. For example, the higher the hydrogen content, the more water vapor is formed during combustion. This water vapor uses energy as it changes phase in the combustion process. Higher water vapor losses when firing the fuel result in lower efficiency. As the fuel is atomized and burning begins, the first fuel constituent to completely combust is the light ends or hydrogen. Remaining after the hydrogen combustion is the devolatilized carbon char. The complete combustion of hydrogen, with adequate diatomic molecules of oxygen in the air, will result in water vapor and heat release.

Excess air results in the free oxygen (excess oxygen) and/or excess air (including nitrogen) to simply move through the furnace causing excessive “dry gas losses.” Simply stated, this is the heating of excess air to the stack temperature and wasting of heat energy to heat air that was not necessary for combustion.

Each fuel is comprised of varying elements such as carbon, hydrogen, oxygen, and sulfur. Smaller amounts of other elements such as phosphorous, nitrogen, mercury, silicone, calcium and iron also are possible constituents in the fuels. These variables not only influence combustion, but also the byproducts of combustion such as slagging, and ash particle resistivity.

All fossil fuels are a mix of large organic compounds and during the combustion process these compounds break down. The two primary elements that contribute to the heat release of the fuel are carbon and hydrogen.

When these elements oxidize *(combine with oxygen)* the carbon creates carbon dioxide (CO_2) and the hydrogen creates water (H_2O).

$$\mathrm{C \quad H \quad O_2 \quad N_2 \qquad\qquad CO_2 \quad H_2O \quad N_2}$$

$$\text{Fuel} \quad \text{Air} \quad \text{Combustion} \quad \mathrm{CO_2} \quad \text{Water} \quad \mathrm{N_2} \quad \text{Heat}$$

Air-Fuel ratios properly controlled across the fuel loading range

Considerations:

- Calibrated gravimetric coal feeders are preferred
- Periodic fuel feeder calibrations for the electronic load cells are recommended
- Periodic verification of feeder output against isokinetic coal sampling rates
- Verification of total combustion airflow proportions, delivery, and optimization

Primary Airflow Measurement and Control

Primary airflow should be accurately measured and controlled within ±2-3 percent accuracy (locally measured vs. indicated). Proper measuring accuracy is especially important at start-up, while establishing a minimum airflow. The primary airflow regulated for a milling system is responsible for transporting the coal through the mill, circulating the coal within the mill and also drying and transporting the pulverized coal from the mill to the burners. In addition, the combustion control system regulates the primary air flow rate to a corresponding fuel flow rate to ensure satisfaction of the boiler master. The following are some major reasons to measure and control primary airflow:

1. To maintain minimum line velocities and minimize the possibilities of coal line plugging. This helps to prevent fuel line plugging and burner fires. It should also be noted that the fuel line (and/or burner nozzle) minimum velocities shall be at least 1005 mpm (3,300 fpm). This allows for a 10 percent imbalance factor to avoid settling to further reduce plugging and/or burner fires.
2. To operate at a repeatable air/fuel ratio for similar flame front distance from the coal nozzle tips for flame scanning repeatability and reliability.
3. To operate with good load response to the turbine or load dispatcher requirements. Primary airflow controls the amount of fuel transported to the furnace more than the coal feeders.

4. Minimize coal rejects due to low mill throat velocities. Coal rejects contribute to coal wastage and risk of fires and explosions if mill throat velocity drops below the entrainment velocity of the raw coal.
5. Maximum efficiency. Too low airflow causes or contributes to items 1 to 4 above. Too high airflow uses more tempering air, and thus has a portion of the increased airflow bypassing the air preheater, and thereby contributing to a reduced efficiency.
6. Too high airflow increases NO_x, especially at lower loads.
7. Non-repeatable primary airflows contribute to changed fuel distributions, and could affect coal fineness or throughput (capacity).
8. Uniform fuel distributions are more likely to be "tunable" with repeatable primary airflow. This contributes to overall better furnace conditions of slagging and fouling, as well as NO_x, fly ash LOI, and auxiliary power consumption.

Note: Flow nozzle or venturi flow measuring elements are particularly useful for measuring where short duct lengths, dampers and temperature stratification's are encountered and should be considered. Venturis and flow nozzles are sometimes required for realistic and repeatable accuracy.

Sample Grid Consideration

In an effort to measure representative air or gas flow, the testing grid should be reasonably spaced with adequate points to represent the entirety of the ductwork. However, more test points are not a substitute for an insufficient number of test ports. Examples of equal area sampling grids are shown as Figures 6-46 and 6-47.

Figure 6-46: Equal Area Chart Example for Square or Rectangular Ducts

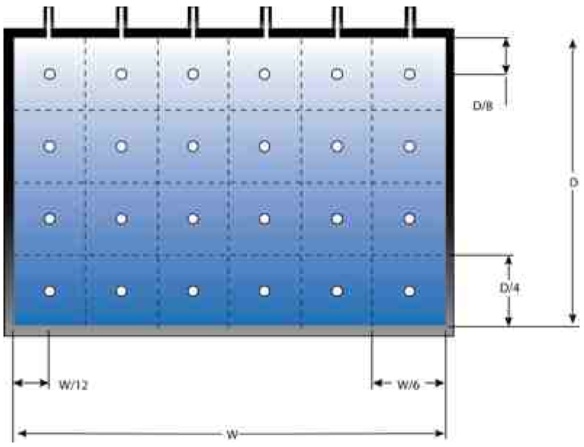
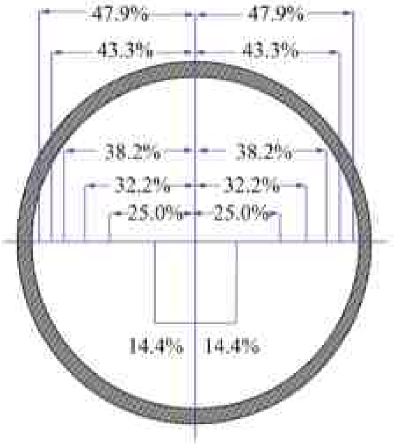


Figure 6-47: Test Port Layout (Round Duct or Pipe) larger than 305 mm (12") for 6 zones.

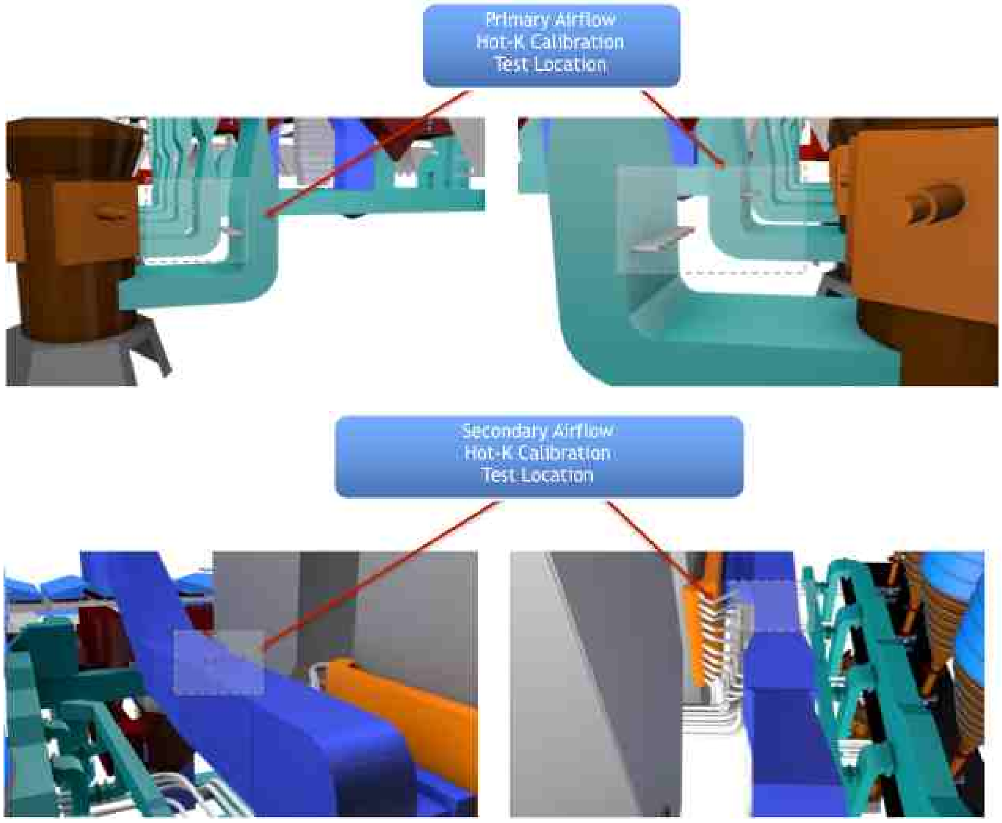


Hot-K Calibration Testing

In addition, total combustion air distribution to the burners should be within ±5 percent. In order to validate this distribution and flow of the secondary airflow to the wind-box, representative secondary airflow measurement ports are required to conduct a periodic hot "K" calibration of the flow elements (as feasible).

A Hot "K" airflow calibration test consists of taking multi-point velocity measurements and static pressure and temperature readings within a hot combustion air duct under normal operating conditions. Ideally, three tests should be performed across the load range of the flow. Then, the variables from the test results can be used to calculate the flow into (or out of), the flow measuring elements [3] .

Figures 6-48: Primary and Secondary Airflow Testing and Calibration Locations



Once the mass flow is determined, the measuring element "K" factor can be determined. The relationship of the pressure drop (P) of the measuring element and the velocity, area, and air density can then be used to develop the calculated curves.

A standard for optimization is to verify that the "K" factor is within the allowable range of 2-3 percent from minimum to maximum flow rates.

A summary of the required testing variables include [3]:

- Representative Static Pressure, Ps
- Representative temperature, Tp
- Representative velocity pressures (vh1, vh2, etc.)
- Area of the measurement location, A
- Barometric Pressure, Pb (inches of mercury or in. Hg) at the test elevation
- "K" Factor of the test probe
- A basic formula for calibrating flow-measuring devices is as follows:

$$w \quad k\sqrt{hd}$$

- Or, the equation can be rearranged to solve for k.

$$k = \frac{w}{\sqrt{hd}}$$

w = airflow

k= "K" factor

h= differential (from differential pressure flow element)

d = density

Once the calibrations are complete and "real-time" flow measuring elements are calibrated and proven, the comparisons of theoretical air vs. measured (or actual) air can be made. An example of a study conducted on a 460 MW unit is shown in Figures 6-49 and 6-50 [12] .

Figure 6-49: Theoretical vs. Measured Airflow at 15% Excess Air (460 MW Unit)

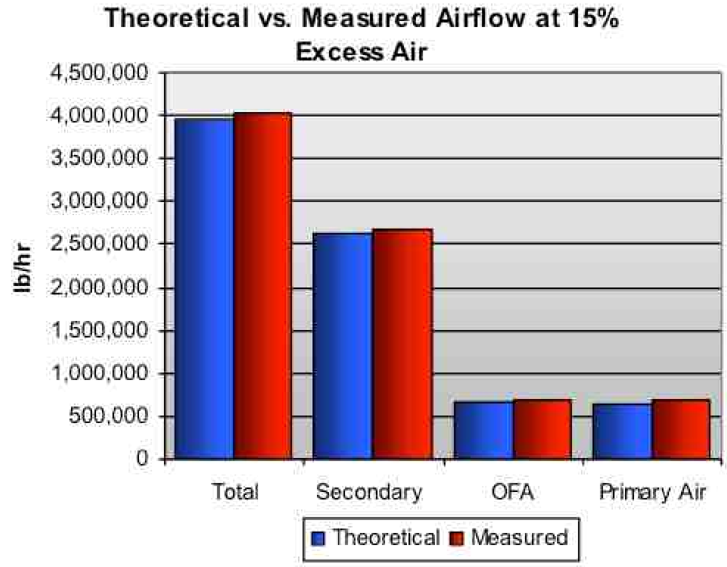
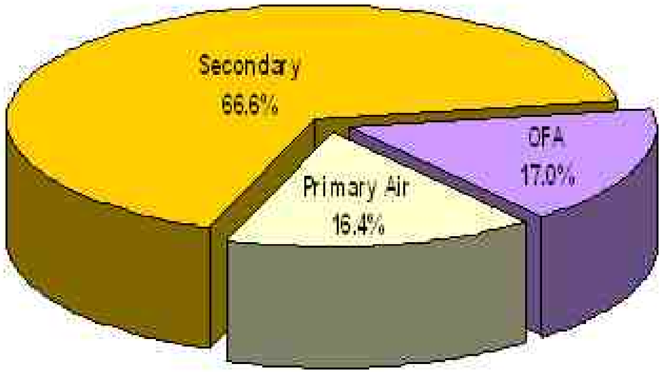


Figure 6-50: Total Controlled Airflow Distribution at Full Load (460 MW Unit)

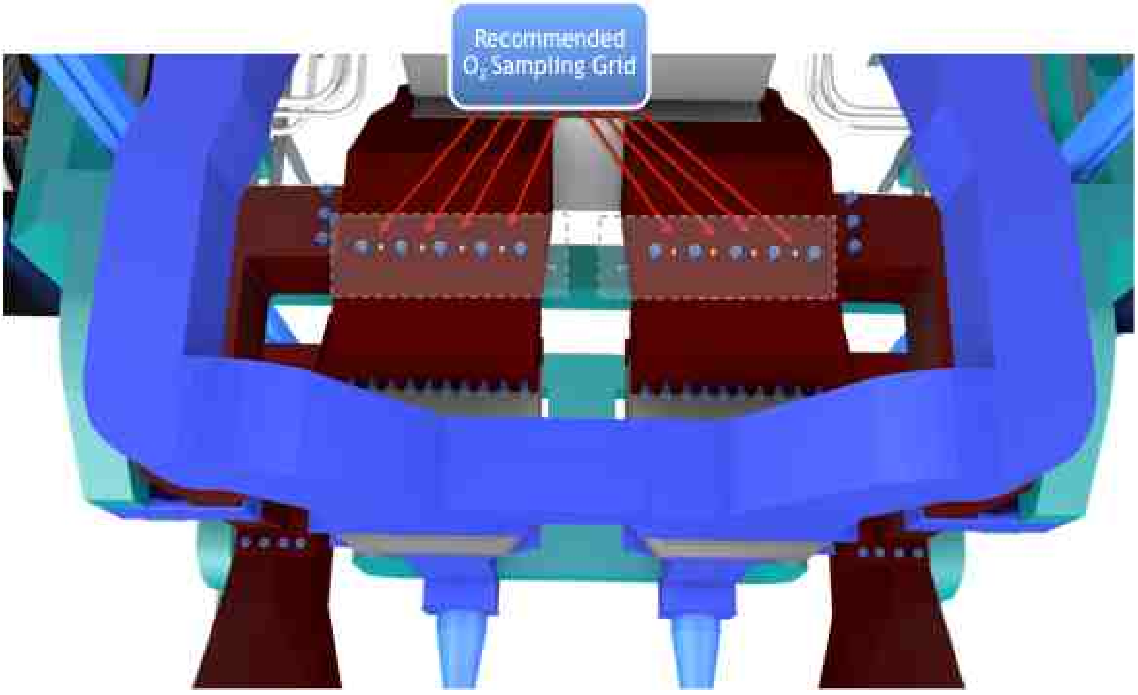


6.7 EXCESS OXYGEN PROBES REPRESENTATION AND ACCURACY

In addition to metering and measuring total combustion airflow properly, it is essential to have representative measurements of excess oxygen to the unit.

As previously noted, inaccurate representation of excess oxygen could be due to air infiltration, but another common problem is non-homogenization of the flue gas. Without a sufficient quantity of excess O_2 measuring probes, the supply of excess air could be too low or high impacting the efficiency of a unit. Considering this, periodic audits of the actual boiler exit flue gas profiles, as compared to the control indicated values, should be conducted.

Figure 6-51: Recommended Location for Equal Area Sampling



6.8 BOILER CLEANLINESS, HEAT ABSORPTION, EXIT GAS TEMPERATURE CONTROL

Outside of normal daily monitoring and trending performance with “online” and “real-time” performance engineering tools, periodic comprehensive and representative diagnostic tests should be completed to supplement the permanent plant instrumentation. Through experience, we have learned that optimal performance demands optimum control, measurement and accuracy of primary airflow, secondary airflow, fuel flow measurement, and sizing of the pulverized coal to the furnace and is of paramount importance. This is considering that proportioning of the inputs to the furnace influences flame propagation, firing patterns, and overall combustion efficiency.

It is also very important that all of the soot blowers be maintained in good working order. For example, when firing higher slagging index coal, the furnace water wall (IR) soot blowers are very important in cleaning the water walls to allow heat absorption that depresses furnace exit gas temperature. The lower furnace blowers are “preventive” blowers in that they clean water wall surfaces to allow increased heat absorption, reducing furnace exit gas temperature below the softening temperature of the ash and preventing slag from accumulating [2, 5] .

Long retractable (IK) blowers are “reactive” blowers that remove slag after it has already formed. The long retractable blowers are only intended to remove accumulations of friable ash and not heavy slag. It is also important to keep in mind that blowing long retracts in the upper furnace can sometimes be counterproductive because furnace exit gas temperature will often remain above the fusion temperature of the ash after they are blown as slag will rapidly accumulate after blowing these blowers.

Also, poor combustion and ineffective wall blowing facilitate sustained operation at FEGT exceeding ash fusion temperature, and slag deposition occurs rapidly immediately after blowing. Considering this, slag formation must be controlled by preventing deposition in the first place and thus efforts should be provided that improve heat absorption in the lower furnace, depressing FEGT below fusion temperatures of the ash.

Proper milling system and soot blowing practices often result in immediate reduction in slagging propensity and the realization of several ancillary performance dividends. For example, improved furnace cleaning can also lower NO_x emissions in some cases because it reduces the size of high temperature region in the furnace capable of producing higher levels of thermal NO_x.

After all blowers are proven functional with proper blowing pressures, soot blower sequences can be optimized using a combination of testing (primarily HVT traverses) and observing unit operation to determine the best selectivity and frequency of blowing. If the permanent exit gas temperature measurement equipment installed agrees with the HVT data, then that data can also be used to evaluate wall blower effectiveness. Furnace exit gas temperature (FEGT) can often be reduced by an approximate range of 111.1°C (200°F) to 138.9°C (250°F) following a full wall blowing cycle with seasoned walls. If FEGT is unchanged after blowing wall blowers, corrective actions must be taken to improve cleaning effectiveness.

The IR blowers or lower furnace blowers should be considered "Preventive" soot blowers which help to suppress and control FEGT (as feasible) to ideally keep furnace exit temperatures below the ash fusion temperatures, while at the same time optimizing steam temperature and spray flows.

The "Reactive" or long retractable soot blowers are located in the upper furnace and convection pass and are used to control slagging after its deposition. These are needed to remove friable, sintered or powdered ash and are normally blown periodically to maintain steam temperatures at optimal levels.

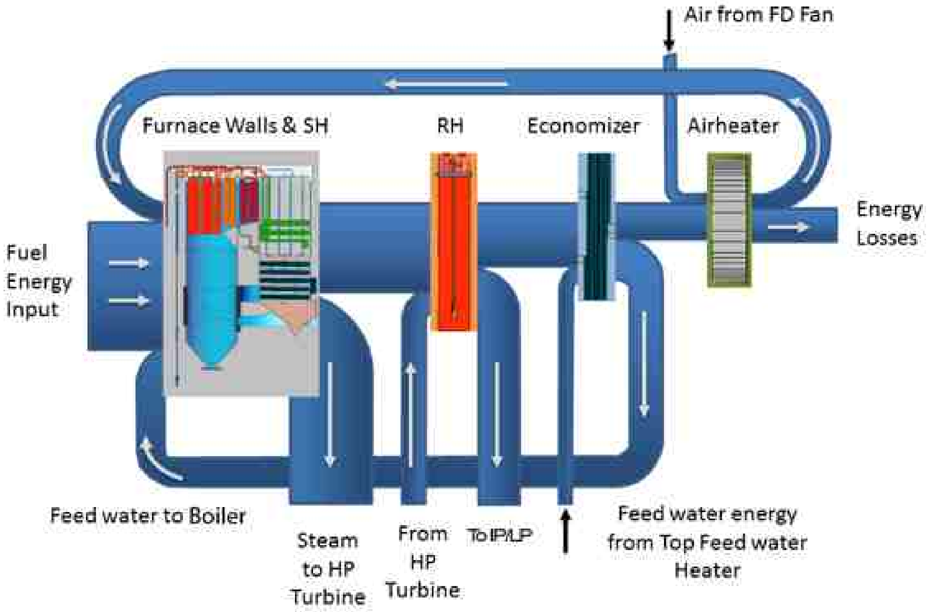
Considerations for Soot-Blowing:

- The control of heat absorption with proper frequency, settings and condition of the soot blowers impacts the overall health and cleanliness of the boiler and air preheater.
- Optimizing the cleaning mediums (quality, velocity, and pressure) can influence not only heat absorption, but also erosion, system draft, and gas flow distribution throughout the entire process by ensuring the gas lanes are clear.
- Different nozzle designs produce different velocities and "shock waves" as the medium leaves the blower. Thus, this impacts the cleaning potential on the boiler tubes being cleaned.
- Fuel and ash quality, slag build-up and tube erosion need to be considered prior to defining the soot blower requirements.
- Soot blowing should be a very dynamic part of a boiler system. This is especially true with fuel variations and high slagging coals.

Understanding Basic Operation and Design of the Boiler

The primary purpose of a boiler is to turn chemical energy into thermal energy. Chemical energy is released by burning the fuel inside a furnace or boiler. Then, heat is captured by the water and steam within the boiler and the final steam output is used to turn a turbine. It is important to understand that the boiler system is a series of heat exchangers and each one of these components has a role in optimizing plant heat rate [13].

Figure 6-52: Validation of Furnace Exit Gas Temperature and Flue Gas Oxygen



In order to validate furnace exit gas temperature, a water-cooled High Velocity Thermocouple (HVT) probe can be used to traverse for two very important reasons:

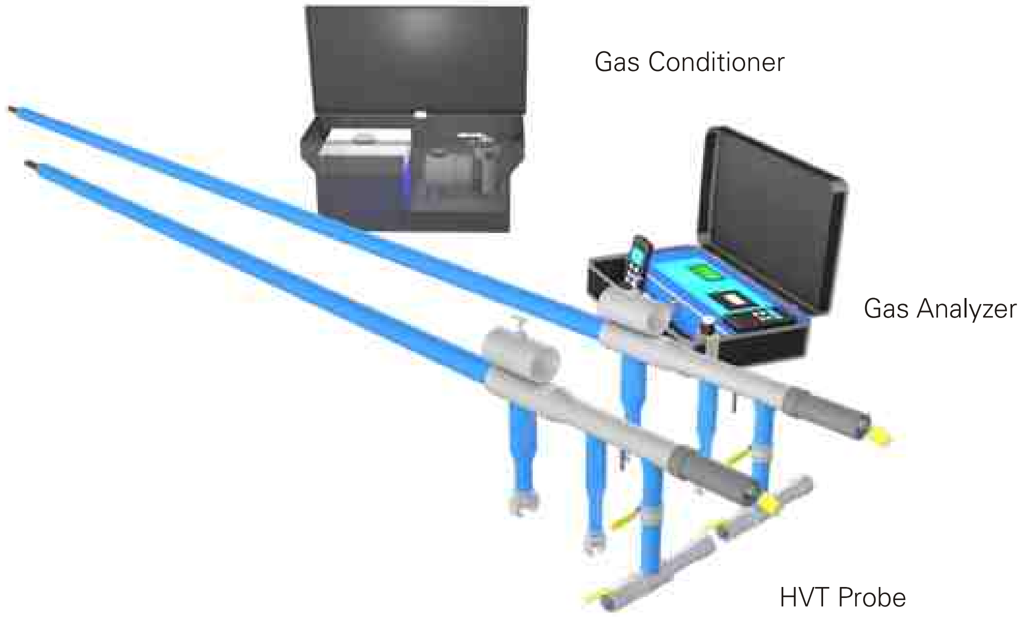
1. Quantify furnace exit gas temperatures (FEGT) to be uniform and optimal
2. Quantify furnace oxygen levels to be uniform with no point less than 2 percent.

By design, an HVT probe is used to accurately measure gas temperature, but its greatest importance is the ability to measure oxygen. The HVT probe is typically inserted in the furnace exit (goose neck elevation) and is the single most important test in diagnosing combustion related problems.

An HVT probe shown in Figure 6-53 is constructed with an internal water line to cool the thermocouple sleeve and an outer return line to cool the probe itself. The thermocouple and a gas sampling line are located in the center of the probe. The aspirator at the end is used to pull flue gas quickly over the tip of the thermocouple (at a high velocity) to negate the effects of radiation artificially lowering the indicated temperature and providing the most accurate assessment of the gas temperatures. Hence, this is where name HVT comes from.

Flue gas can be extracted from the probe using a flue gas sampling conditioner that has an integrated pump to overcome the negative pressure commonly found in the furnace. In addition, the conditioner should filter and remove moisture and debris before the gas as it enters the portable flue gas analyzer.

Figure 6-53: HVT Probe and Gas Sampling Equipment



HVT purpose

Water-cooled HVT probes are important for validating permanent instrumentation (if installed). Also, most importantly they can be used for accurate measurement of flue gas oxygen and other flue gas constituents at the furnace exit.

At different points throughout the unit, air can infiltrate the flue gas (primarily on balanced draft units where the flue gas is under negative pressure from the suction of the ID Fan). Over time, steam generators have a common tendency towards high air in-leakage. Air in-leakage through the penthouse, nose arch dead air space, bottom ash hopper dead air spaces, expansion joints, and the boiler settings are commonly assigned very low maintenance priority. However, these items are much more critical to unit performance than most realize [3,8,11].

Typically, excess oxygen is controlled by indicated oxygen at the economizer exit. When high levels of air in-leakage infiltrate the flue gas with oxygen prior to its measurement at the economizer exit, this can represent in very low oxygen levels in the furnace causing the flame to quench in the super-heater before the char has a chance to completely burn. This can cause high LOI (Loss of Ignition), commonly referred to as unburned carbon, high CO, and decreased boiler efficiency.

High air in-leakage also results in increased dry gas loss due to the heat absorption of tramp air that did not pass across the air preheaters. If the excess air level is raised to obtain an oxidizing atmosphere in the furnace without reducing air in-leakage, higher than design draft losses is be incurred. Air in-leakage also causes the boiler exit temperature to appear falsely low. The "tempering" effect of the cool ambient air in-leakage lowers indicated boiler exit gas temperature, when in fact, if corrected for leakage, exit gas temperature would be much higher.

Numerous other complications are also the result of this condition. Some of these are as follows:

- Secondary or delayed combustion that causes combustion higher in the furnace, reducing water-wall heat absorption and resulting in high furnace exit gas temperature.
- High furnace exit gas temperature (FEGT) combined with existence of a reducing atmosphere also leads to the following:
  - Decreased combustion efficiency
  - Overheating of superheat and reheat tubes
  - Tube wastage and the subsequent tube thinning caused by a reducing atmosphere can result in future tube failures
  - Aggravation of coal-ash corrosion
  - Increased de-superheating spray flow
  - Serious slagging and fouling of heating surfaces; a reducing atmosphere lowers the ash fusion temperature. Combined with the high temperature, a reducing atmosphere leads to increased slagging.

The resulting high furnace exit gas temperature combined with existence of a reducing atmosphere can lead to increased cycle losses due to increased soot blowing as a result of fouling and slagging of heating surfaces. High boiler exit gas temperature can lead to the accelerated deterioration of the air preheater heating surface and possible degradation of precipitator performance. High leakage can result in reduction in available ID fan capacity and subsequent de-rating of unit generation and availability.

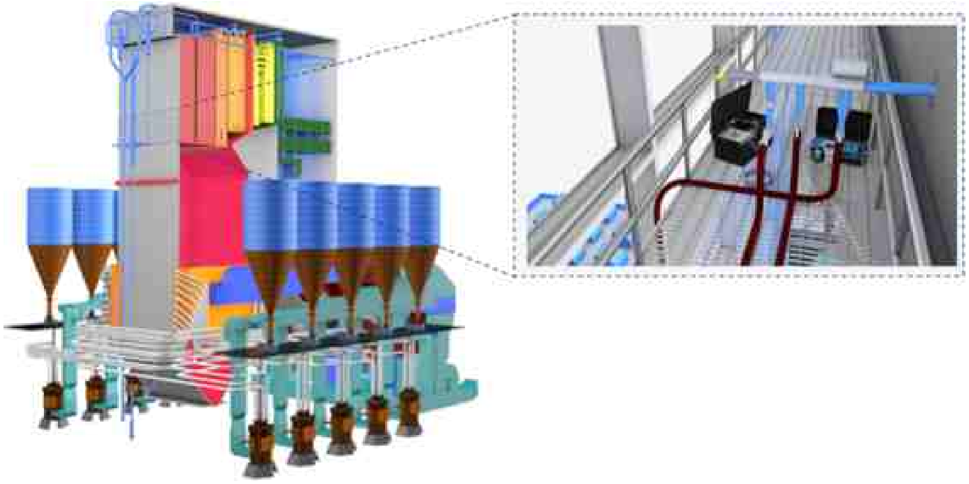
Temperature and oxygen profiles obtained by the HVT traverse can also be an indication of imbalances in air and fuel originating in burner belt zone. Fuel imbalances, combustion secondary air imbalance, closed air registers, plugged fuel lines, etc., are easily confirmed by the temperature and oxygen profiles determined by an HVT traverse. It is also useful to compare side-by-side fly ash LOI and slagging tendencies with HVT oxygen profiles.

The HVT Traverse Process

1. Ideally, a monorail will be used for ease of insertion of the HVT probe into the furnace.
2. Adequate water supply and pressure must be provided to the probe prior to insertion. Failure to do so will result in overheating and damage the probe.
3. Air and water supply and water drain provisions are also required to ensure a safe working environment. Also noting that the disconnection of a hose during a test could result in damage to equipment or personal injury.

4. The test probe should be marked and positioned incrementally, ensuring that the thermocouple is 2.54 cm (1") from the tip of the radiation shield. The thermocouple should be centered not touching any part of the radiation shield.
5. When extracting gas samples, a gas conditioning system is required to ensure that rapid and filtered gas is provided to the analyzer in a prompt manner.

Figure 6-54: Typical HVT Test Elevation



Prerequisites

- Major equipment and auxiliaries (water and air supply; drain system)
- Inventory of consumables (analyzer and gas sampling system)
- Proper testing protocols
- Personnel training process
- Equipment and Instrument maintenance program
- Integration of procedure with the combustion and boiler performance tuning process.

When testing, it is important to let the gas analyzer settle out at each point. This usually takes one to two minutes. Once the readings are steady; record the highest and lowest O_2 percentage indicated. The maximum temperature, NO_x and CO readings are recorded as well for combustion performance evaluation. After the entire grid has been sampled, average the high and low O_2 readings together for the average oxygen content for the furnace exit.

Table 6-4 represents a typical data collection sheet.

Table 6-4: HVT Test Record Sheet

Unit		Location		Start Time	
Date		Test No.		Stop Time	

Depth (Insertion)	Temperature (°C, °F)	Oxygen (Low Value)	Oxygen (High Value)	CO (PPM)	NO_x (PPM)
2′					
4′					
6′					
8′					
10′					
12′					
14′					
16′					
18′					
20′					
Averages					

Deployment Recommendations

- Conduct manual HVT testing at least four times per year (per unit) or quarterly; these tests should be used to validate "real-time" temperature and flue gas measuring equipment (as available).
- Ensure provisions are made to conduct HVT traverses if there appear to be fuels, visual or instrumentation accuracy issues that could jeopardize reliability of the unit.
- Stage the HVT probe on the boilers. Ideally, a monorail will be used for ease of insertion into the furnace.
- Consider implementing permanent water, air and drain lines for the respective HVT test locations to make the task "user friendly."

Additional HVT Testing Illustrations

Figure 6-55: HVT Test Illustration

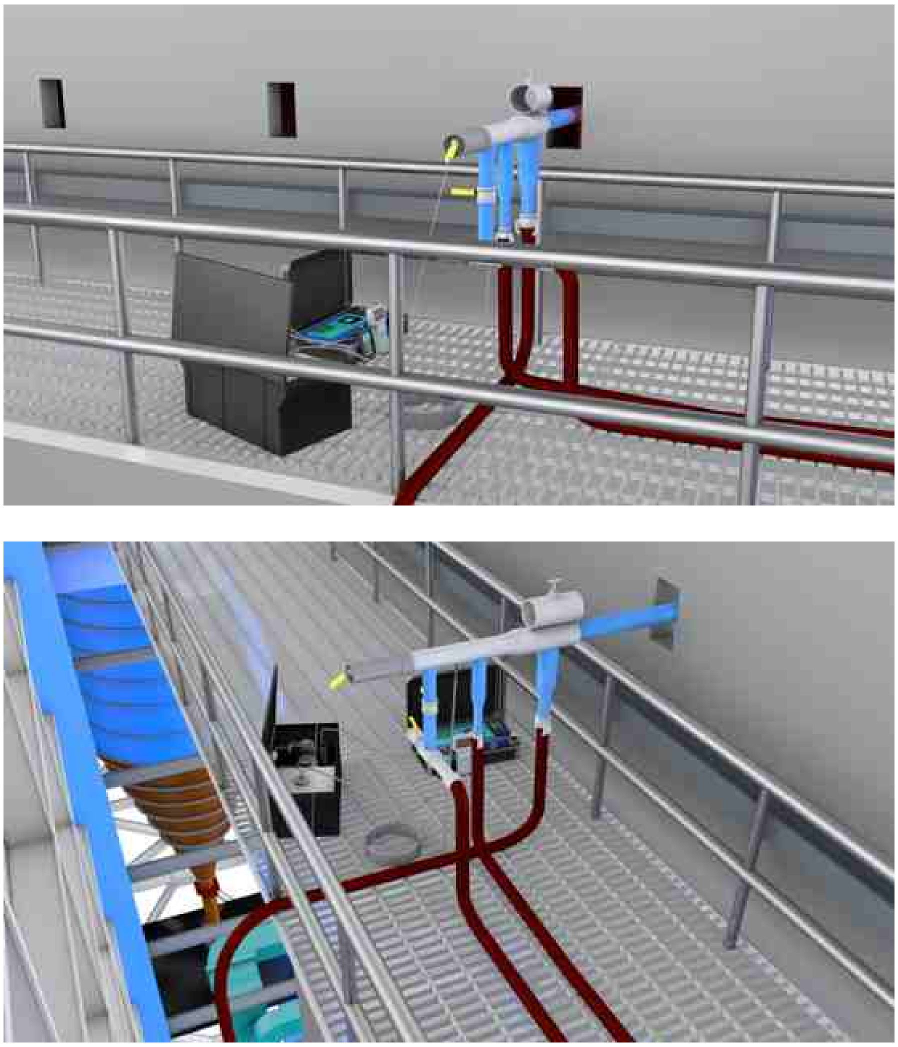


Figure 6-56: Monorail Concept For “User Friendly” HVT Measurement

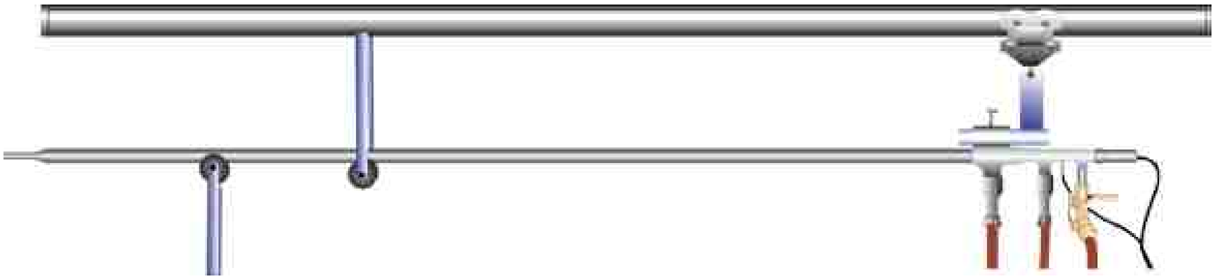
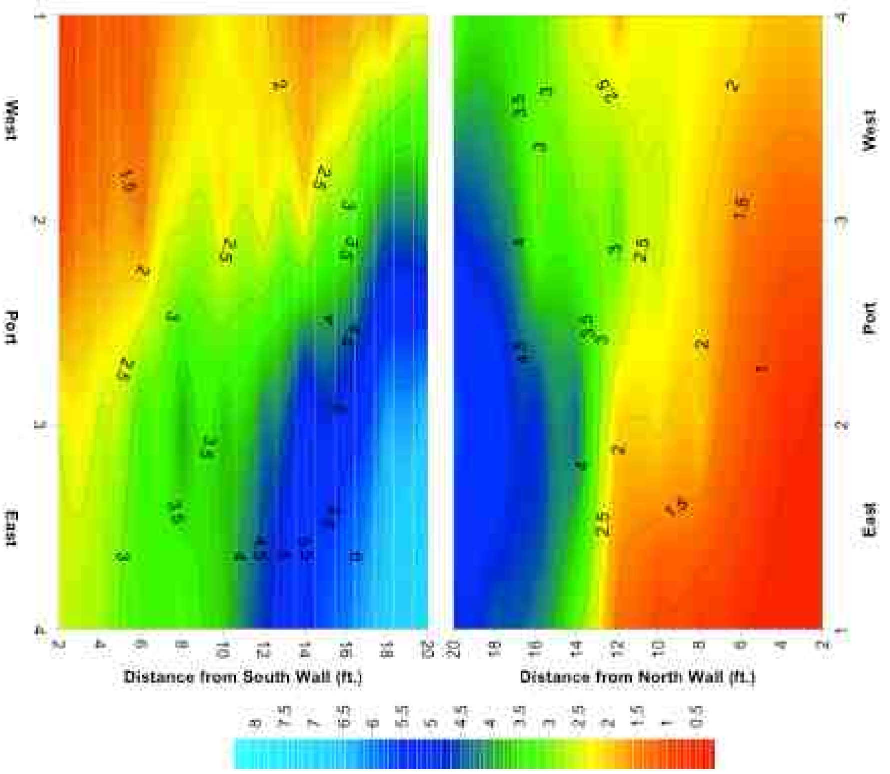


Figure 6-57 represents an example of oxygen profiling results after the use of an HVT probe.

Figure 6-57: HVT Test Results Plot



6.9 REGENERATIVE AIR PREHEATERS

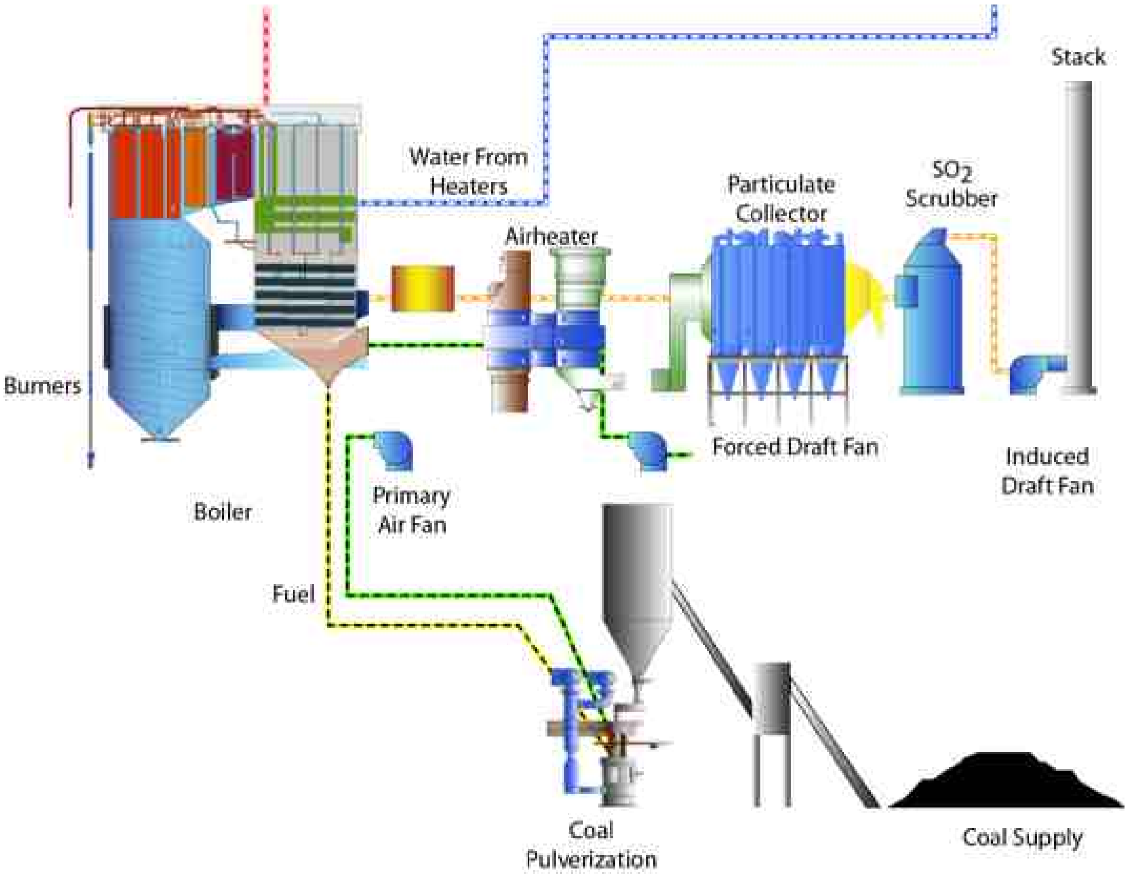
Regenerative air preheaters have mechanical and moving components that transfer and recover heat energy.

A few common challenges with air preheaters include:

1. Leakage of air
2. Plugging and increased pressure drop
3. Poor heat transfer

When these occur, the flue gas temperature is reduced and gas mass flow increased. Thus, it is important to understand that this decreased efficiency impacts both the boiler performance and all equipment downstream of the air preheater.

Figure 6-58: Typical Arrangement of a Regenerative Air Preheater [13,14,15]



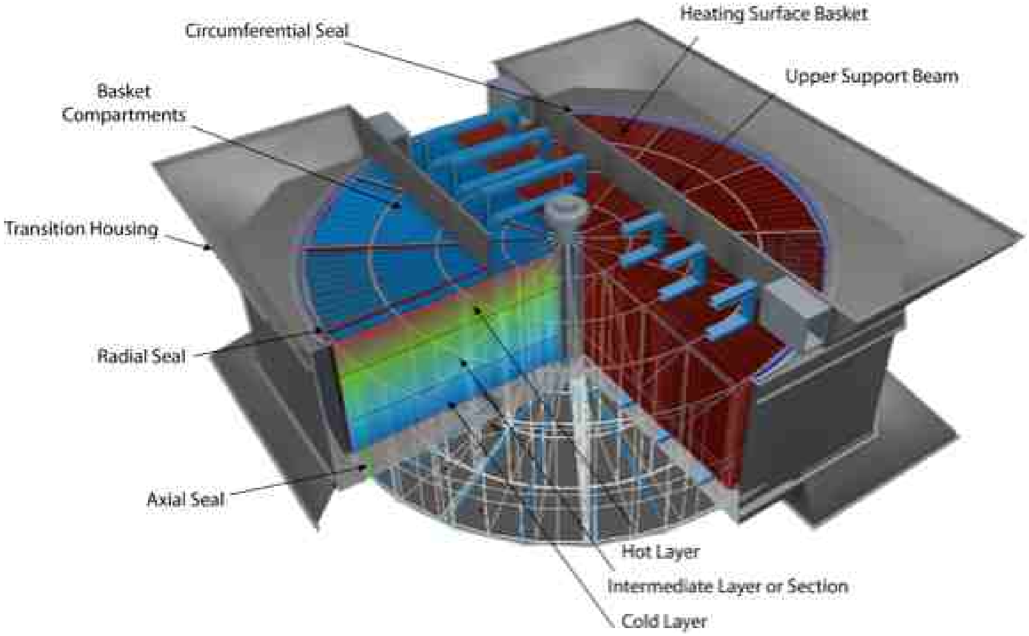
One of the most common design air preheaters, the Ljungstrom design, uses a rotating rotor in a shell filled with "baskets" that contain thin gauge metal heating elements with strategic profiles.

Figure 6-59: Examples of Common Profile Designs

The flue gas duct is routed to pass through one side of the rotor while the air duct is routed to pass through the other side. As the rotor rotates inside the gas duct, flue gas heats the baskets. When the heated baskets rotate into the air stream, the passing air is heated. Then, the cooler baskets rotate back into the flue gas to be reheated. The rotor speed is typically controlled between 1 and 5 rpm (depending on the rotor size).

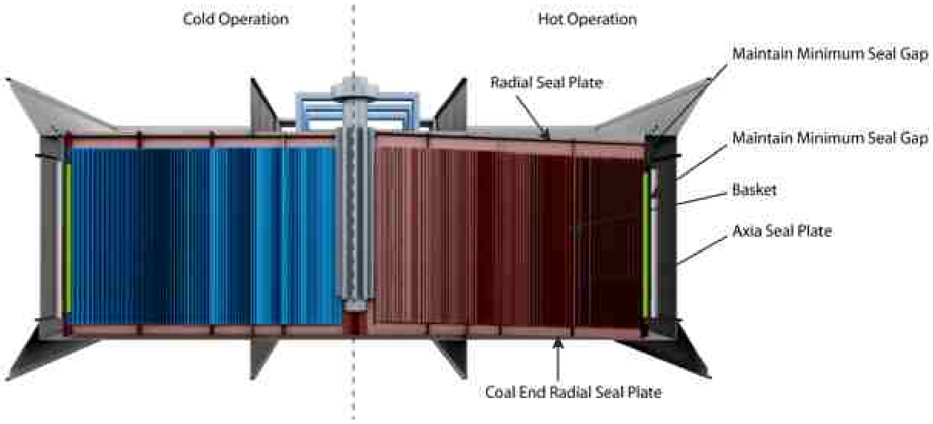
Because there is rotation involved, sealing systems are used to minimize the leakage from the high-pressure air to the gas side. On a Ljungstrom air preheater, there are three different seals: radial, circumferential, and axial. The radial seals mount on the diaphragms of the air preheater baskets and provide radial sealing across the sector plate on the air preheater. This in turn separates one side from the other. The circumferential or bypass seals go around the outside perimeter, sealing air that could escape around the shell. Then, the axial seals are mounted on the outside of one basket and are parallel to the drive shaft [13,14,15].

Figure 6-60: Typical Bi-Sector Air Preheater Construction



As the air preheater rotor heats up, it experiences thermal expansion and thus proper setting of air preheater seal gaps is very important. Seals too tight can bind up the rotor and/or damage the seals. Seals too loose create excessive leakage. The hot end of the air preheater expands more so than the cold side due to thermal expansion. This is referred to as "turn-down." If the flue gas inlet temperature is too high, this can create too much of an expansion on one side.

Figure 6-61: Illustration of Air Preheater "Turn-Down"



Since the gas lanes through the basket are narrow, ash tends to collect on them. Use of a soot blower is often necessary to keep the baskets clean. If the ash builds up too much, the differential increases forcing more air to bypass the heater and short circuit to the gas outlet side of the air preheater. This can create extra flow to an ID fan that may already be struggling due to the increased differential. Furthermore, because the air leaking into the system is colder than the flue gas, the temperature will decrease. This limits the heat transfer ability of the air preheater considering that the leakage decreases the efficiency of the air preheater and thus the heat transfer rate [13,14,15].

It should also be noted that the pressure differential across the cold end seals is higher than the pressure differential across the hot end seals because the FD fan is pushing on the air preheater while the ID fan is pulling. These effects are weakened through the air preheater reducing the differential on the hot side. Therefore more air leaks through the cold side than the hot side. When air leaks through the cold side, no heat transfer has taken place yet, so there is no penalty. However, when hot end leakage occurs, air has already passed through the baskets first where it is heated up. This hot air then mixes with the gas and the heat that should have been carried to the furnace is now taken up the stack. The problem is that the air preheater testing does not show where leakage occurs, it shows only how much. Penalty assessment must rely on the leakage calculation and the corrected exit gas temperature to address heat rate penalties.

Note: the corrected air preheater outlet temperature calculation assumes that all of the leakage occurs on the cold end side. In reality hot end leakage could account for between 5-40 percent of total leakage.

Figure 6-62: Air Preheater Heat Flow

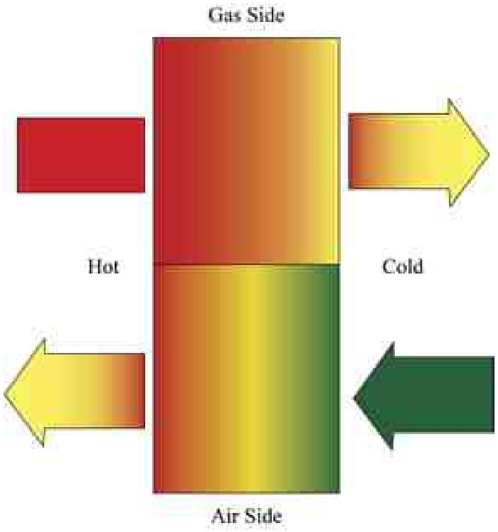
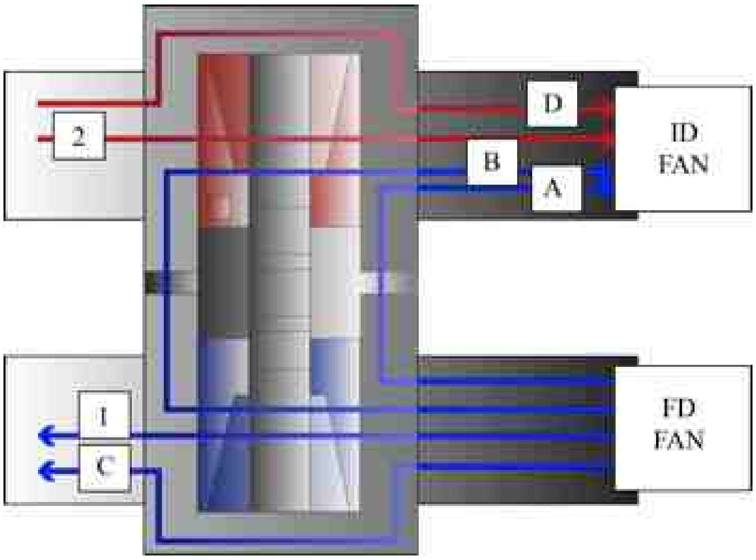


Figure 6-63: Air Preheater Leakage Paths [13,14,15]



In the figure the leakage paths are:

Path 1: Normal air flow path

Path 2: Normal gas flow path

Path A: Ambient FD fan leaking directly to the APH Gas Outlet

Path B: Pre-heated FD fan air flow short circuiting the APH

Path C: Ambient FD fan air leaking around air preheater.

Path D: Hot gas that exits boiler

General Inspections for Boiler Setting - Air In-leakage and Regenerative Air preheaters

Equipment reliability and performance have parallels. Indications of poor performance are closely tied to those of reduced reliability. Abnormal wear patterns, poor cleanliness, increased corrosion, and mechanical failures, no matter how small, have effects on both unit reliability and unit performance. Identifying the root cause is the first step in improving the overall performance of a piece of equipment including power generating unit. Therefore, prior to outages, the following are some best practices to consider:

- Review the last boiler and equipment inspection reports
- Review recent operating history for the boiler efficiency and regenerative air preheater performance. At a minimum, these should include the following:
    - Boiler efficiency
    - Regenerative Air preheater Performance

  - o Leakage
  - o Efficiency
  - o X-Ratio
- ➢ Draft, pressure drops, both air and flue gas sides (including all fans, ducts, wind-box, furnace, convection pass, air preheater, air pollution control equipment
- ➢ Past inspection and forced outage reports to review trends /issues
- ➢ Abnormal operating events
- ➢ Contact plant operations for additional information on operating history

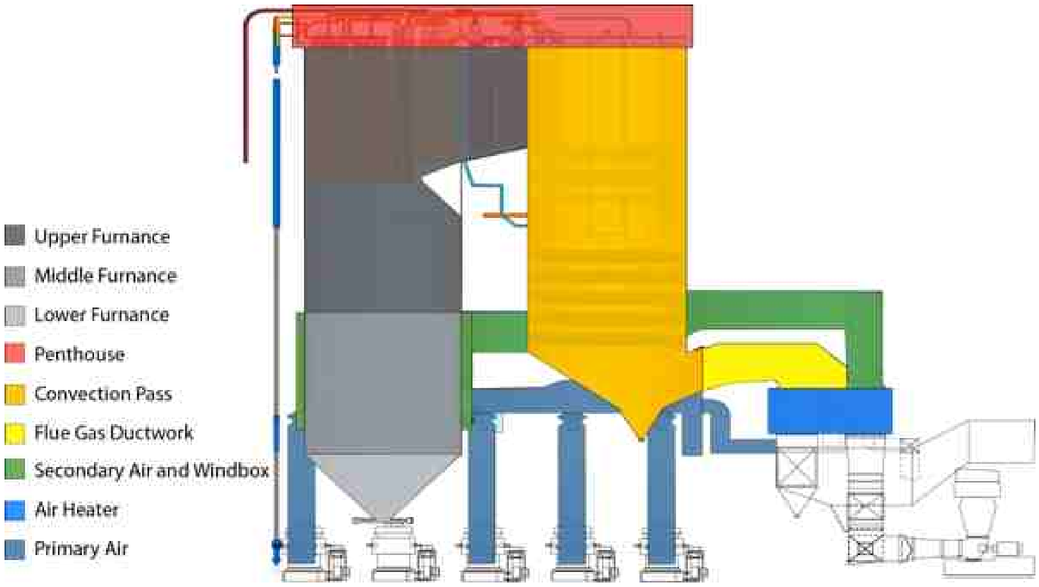
The following drawings should be obtained prior to inspection (as feasible) to aide in the inspection and report/documentation:

- Elevation - boiler, fans, airflow ducts, flue gas ducts, air preheater
- General layout

It is recommended to use thermography to locate hot or cold spots on the external casing of the air boiler, ducts and/or air preheater. Thoroughly evaluate all deteriorated insulation and casing.

An example side elevation with the primary boiler and/or rotary air preheater inspection points on a 600 MW Supercritical boiler is shown in Figure 6-64:

Figure 6-64: Illustration of Inspection Locations for A-SC Boiler Air In-Leakage



Exterior Heat Loss Evaluation

The unit loses heat through the exterior walls of the furnace and ductwork. If the surface temperature is reduced through insulation or lagging, then the amount of heat leaving the unit is reduced and efficiency increases.

As the temperature difference between the surface and the surrounding air increases, heat transfer increases. Normally, as the air heats up, the heat transfer slows down because the temperature difference becomes less and less. Slowly the heated air begins to rise above the cooler air and the cold air takes the place of the now heated air. However, if the heated air is blown away by the wind or by a draft faster than it would normally rise, then the heat transfer does not slow. This is called forced convection.

Each of these losses can be measured by mapping temperature and wind speeds. However, considering that the losses are typically small compared to other opportunities identified during an outage, all of the boiler inspection locations should be monitored, measured with an infra-red/thermal imaging camera to determine if there are exterior heat losses which warrant insulation replacements that may be required during an outage [10].

Overall System Air In-leakage Inspections

Boiler, ductwork, air preheater, and fan inspections should be undertaken as a team effort. Utilizing Inspection team members from maintenance, engineering, and operations broadens the view and improves the findings. It is recommended that one person serve as scribe and another carry the camera or video recording device. The notes/records may be recorded in writing or via sound recording to be transcribed immediately thereafter. Upon exiting the air preheater, all notes, records, and photographs should be duplicated and stored separately to ensure preservation of this information.

This is a multi-part inspection, first prior to any cleaning, then after cleaning, and even later if needed. All notes and recordings should be accurately labeled to ensure future reference to the correct issues as identified.

Crawl-through Inspections – Prior to Cleaning

The first inspection should be conducted prior to any cleaning activities as deemed safe for entry. This initial inspection is for the purpose of identifying accumulation of ash, overall boiler cleaning/vacuuming needs, as well as areas of air in-filtration by viewing air washed areas, mechanical discrepancies with tube alignment and any issues that would accelerate localized erosion, change the furnace performance and dynamics, impact heat transfer, etc.

Photograph, video, or sketch of the general condition of the unit - piles of ash or slag may be significant - recording their size and location is important; wear and patterns of soot blowers should be observed. Any signs of debris, foreign material, and corrosion products should be noted. Instruments and their connections should not be buried, covered, or insulated by mounds of ash or other debris.

Second Inspection – Post-cleaning/Scaffolding

A second and thorough inspection should be conducted after initial vacuuming, cleaning of the boiler and/or a water-wash down. This inspection enables those entering the unit to observe the actual mechanical condition of the components: wear patterns, cleaning patterns, alignment, mechanical issues of any sort. Any signs of debris, foreign material, and corrosion products should be noted. Material and tools may have been inadvertently dropped from work in the ductwork above the air preheater. Identifying the source of the foreign material will assist in preventing its recurrence. A localized concentration of corrosion products is typically the indication of a problem. A further investigation is warranted to determine the root cause and potentially prevent recurrence.

General Boiler, Ducts and Fans - Air In-Leakage Inspections

General Inspection Areas

A general inspection should include a preliminary crawl-through inspection that immediately includes comments regarding the general boiler condition, tube alignment, areas of erosion, plugging, etc. The boiler condition and paths for air and gas delivery can influence a unit's performance in such a way that combustion dynamics, thermal efficiency, and the overall ratio of the air and gas paths influence the operational performance and reliability of the unit. An outline of a general inspection is listed below:

Lower Furnace

- Note tube erosion and/or wastage (if any), pay careful attention to the upper transition bends and lower throat bends for wear.
- Evaluate the lower slopes for quench cracking from possible bottom ash water splash.
- Evaluate and inspect for any possible gouged, crushed, sliced and dented tubes.
- Seal trough-bottom ash hoppers erosion/corrosion.
- Note Ash pit condition (refractory / general). In addition, inspect for jet nozzle condition and positioning.
- Check the Ash hopper water seal (if applicable).
- Clinker grinder/Drag chain (if applicable).
- Inspect sidewall and buckstay damage adjacent to and behind the lower slopes as a result of possible clinker fall.

Mid Furnace

- Access Doors
- Closure / Seal
- Refractory (inside furnace)
- Wind Box casing
- Soot Blower lance penetrations
- Seals
- Refractory (inside furnace)
- Tube Alignment / Wind-box / Furnace Casing Construction

Lower – Mid-Upper Furnace Inspections / Observations

- Tube Alignment / Wind-box / Furnace Casing Construction
- Slag and fouling pattern. Identify unnecessary slag traps on waterwalls (i.e., previous water cannon opening no longer being used, etc.)
- Burner zone condition. Inspect for flame impinged tubing
- Furnace (lower slope and division wall - UT/erosion/corrosion). Identify all peg fin and membrane sections observed to exhibit fatigue and cracking
- Radiant section - UT/alignment/erosion/corrosion
- Note any or all blister/bulges
- Convection passes - UT/alignment/erosion/corrosion/overheat/creep
- Economizer - UT/alignment/clips/erosion/corrosion

Dead Air Spaces

- Lower Furnace. Note slope tube/I-beam support intersection for damage, including clip condition
- Identify casing/membrane breach locations to the furnace side. Record ash accumulations, and observe condition of pressure part components for corrosion possibilities
- Nose arch Apex. Inspect for casing/refractory breaches to the furnace side, record all locations found
- Inspect all structural steel supports and beams for integrity due to potential overheating if breaches are found
- Penthouse

Fans *(Forced Draft, Induced Draft, Primary Air, Seal Air, Gas Recirculation, Over-Fire Air - if boosted, and Burner Cooling Fans):*

- Fan Housing
- Fan wheel observations – Fly ash erosion – tip cracks, loose bolts or rivets, rubs
- Inlet vanes - stroke, fly ash wear, linkage, bushings
- Inlet louvers – outlet dampers – check stroke, fly ash erosion, linkage pins/bolts
- Casing wear
- Blade condition
- Shaft seals
- Inlet/Outlet Ducts/Joints
- Inlet Box Screens (if applicable)
- FD Fan Discharge Duct/Steam Coils (if installed) Cleanliness and Condition

Wind Box/Secondary Air

- Synchronize secondary air dampers and verify operation from inside and outside damper drive limits and travel
- Burner tilts
- Linkages
- Draft Gauges

Over-fire Air

- General condition
- Dampers and registers
- Tilt and yaw (tangentially fired units)

Instrumentation

- Airflow measurement elements
- Pressure/taps/sensing lines/connections'
- Leak Checks
- Temperature/wells

Ductwork (Air Ducts, Gas Ducts, and Economizer Hoppers)

- Fly ash Erosion
- Expansion Joints
- Casing cracks – joint integrity – corrosion
- Ductwork supports
- Fly ash weight accumulation damage

Burners (Signs of erosion/physical damage/malformation)

- Mechanical Tolerances
- Condition/Centering (Wall-Fired)
- Tilt/Yaw Adjustment (Tangential Fired)
- Igniters
- Air Registers
- Nozzle Condition
- Separated Air Zones
- Burner refractory
- Condition
- Angle

Burners should be refurbished to design/optimum conditions

- Fuel Pipe Orifices
- Burner throat refractory
- Coal pipe nozzle
- Diffuser vanes, position
- Oil gun position relative to diffuser
- Gas ring/spuds
- Burner register vanes/actuating linkage /actuators

Soot Blowers/Performance

- Ensure all blowers are in working order
- Install tube shields and repair thermal drains (as required). Verify the saturation state of the supply steam/air, and take action to reduce condensate.

- Note lance corrosion (if any)
- Note General operation / stroke / alignment. Verify timing of blow sequence. Verify pressure
- Soot Blower performance is also essential to ensure the gas lanes are clear, flue gas dynamics are equalized and localized erosion is minimal; Evaluation of performance should be noted by visual observation prior to boiler cleaning
- Note ash bridging at the SH (if any)
- Note cinder carry-over into the convection pass (if any)

Penthouse

- Hanger rod corrosion / condition. Identify all loose hanger rods.
- Roof seal condition
- Weather proofing – lagging condition – joint integrity
- Penthouse Floor. Inspect roof tube support clips when accessible.
- Seal Boxes/Crown Seals
- Tube penetrations
- Determine air washed areas / intensity of leakage as viewed from the boiler side
- Refractory Condition
- Iso-membrane Condition (if installed)
- Verify header wrapping and insulation condition
- Inspect all terminal tubes for overheat/creep exfoliation conditions and UT verify remaining wall thickness where accessible
- Inspect all header supports and connections for integrity

Access Doors

- General Condition/Closure
- Gaskets/Sealing

Convection Pass

- Erosion Baffles
- Gas Lanes
- Casing and header penetrations
- Improved RH and SH damper control

Access Doors/Hatches (all)

- Closure/Hinge/Seals

Environmental Control Equipment (Typical)

- SCR
- Hoppers / Mechanical Collectors / Turning Vanes / Delta Wings
- ESP
- Gas seals around rapper and vibrator rods
- Dust accumulations in ducts and on plates and wires
- Plates – alignment, structural attachments, bowing
- Penthouse heaters and blowers (if applicable)
- Rappers, Vibrators, Electrical connections
- Bag house
- FGD/Scrubber (wet/dry)

Regenerative (Rotary) Air preheater Inspection

- Housing
- Thickness
- Erosion, Corrosion Damage
- Deformation, Warping
- Weld Cracking
- Expansion Arrangement

Basket Frame Inspection

- Basket Condition/Bypass
- Basket Support/Attachment

Rotor Inspection

- Rotor Post to Diaphragm Joint
- Diaphragm, Grating, Shell Plate (Thickness, Warping, Cracking)
- Pin Rack (Attachment to Shell, Pin/Pinion Wear)
- Pinion Gear Contact with Rails

Heating Element Inspection

- Layer Design (i.e., 2 layer or 3 layer)
- Profile Description/General Condition
- Surface Condition
- Plugging/Cleanliness
- Tightness
- Cracking/Break-up
- Soot blower damage (if any)

Rotor Sealing Arrangement

- Radial and Circumferential/Bypass/Axial Seals/Post
- Bent, Deformed, Thinning
- Clearances
- Contact with Sealing Surfaces
- Fasteners

Sealing Surfaces

- Maintaining a tight seal on the air preheater is essential for optimization of the combustion air fan capacity (FD/PA) in regards to the combustion process and also such that the ID fans do not exceed capacity, limit load and/or consume unnecessary power consumption. During inspection, the rotation and corners of each sector plate should be numbered to reference the location for all areas of contact (Hot and Cold ends – Radial, Bypass and Axial).
- Surface Wear, Thickness, Holes
- Cracking, Warping
- Alignment, Adjuster Condition

T-Bars

- Surface Wear, Thickness
- Cracking, Warping
- Fasteners

Rotor Drive System / Mechanisms

- Oil level, Leakage
- Pinion Gear Wear

Rotor Bearings

- Oil Level, Leakage, Contaminations
- Oil Circulation System, Filters
- Evidence of Wear, Clearances

Cleaning/Washing Equipment

- Condition

Instrumentation

- Static pressure Taps/Sensing Lines
- Differential 4-20mA transmitters
- Excess Oxygen Probes/Online Analyzers
- Thermocouples
- Air Inlet
- Air Outlet
- Gas Inlet
- Gas Outlet (Cold end thermocouple condition/representation)

Auxiliary Equipment

- Rotor Stoppage Alarm
- Leakage Control System
- Infrared Detection System

Expansion Joint, Ductwork, Support bracing

- General Condition
- Check for erosion and/or leakage

Dampers

- Isolation
- Bypass

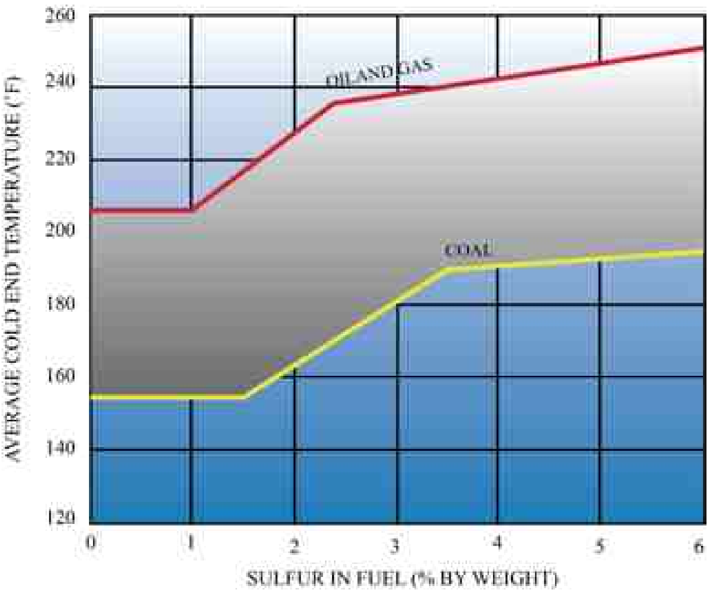
Effects of Cold End Corrosion

With low Sulfur fuels, "cold-end" corrosion is not a typical problem in India. However, it is a common problem that regenerative air preheaters have in the U.S. when firing high sulfur fuels. Considering that fuels are being imported into India, cold-end corrosion is worthy of a discussion.

Cold-end corrosion not only destroys baskets, it also opens up the seals and create more leakage. As the rotor passes through the cold side it picks up moisture onto the baskets. When it passes through the hot side, ash and flue gas come in contact with this moisture. If there is high sulfur content in the gas/ash, it can mix with the moisture and create sulfuric acid, but only if the temperature is below the dew point (in most cases the flue gas is controlled above it). However, as the rotor passes out of the hot gas and into the cold air, it can also cause the mixture of gas and ash to reach the dew point before it cycles back into the hot side. This process repeats every time the rotor turns. Because of problem like this in colder climates, steam coil preheaters at the inlets to the fans as well as APH bypass may be necessary. In India, this is not common and likely is not necessary, but should be addressed.

Any leakage at this point is now a part of the flue gas flow. So, correcting for the actual exit gas temperature is necessary. The cold side of the air preheater is of particular concern with corrosion. As SO_2 gas mixes with moisture, it creates sulfuric acid vapor. When the temperature is low enough, this vapor can reach the acid dew point. The acid condenses on the air preheater baskets and surrounding ductwork and metal. Maintaining a minimum metal temperature is critical. Therefore monitoring of the average cold end temperature is common when firing high sulfur coals. The average cold end temperature is the average of the inlet air temperature and the outlet gas temperature with regards to the air preheater. This temperature is maintained lower for natural gas units and higher for eastern coal units due to the fuel sulfur content [13,14, 15].

Figure 6-65: Typical Average Cold End Temperatures for Different Fuel and Sulfur Content



Steam coil air preheaters are often placed in the airflow ductwork right after the FD fan to provide some initial heating to prevent cold end corrosion. A steam coil is constructed of multiple lines crossing through the airflow. Each line has fins on it to help with heat transfer. Steam or heated feed water is piped through for the source of heat. These can be turned on during cold weather or start-up and turned off when not needed. It is important that these be periodically leak-checked during outages. A drawback of using a steam coil is increased pressure drop resulting in a higher FD fan demand. Making sure the fins are straight and clean helps alleviate some of the pressure drop.

In some cases, air preheater bypass systems are used as an alternative to steam coil air preheaters.

Testing air preheaters requires traverses across both the air preheater gas inlet and gas outlet. Once the data is collected, average oxygen and temperature readings should be average for each inlet and outlet. These values are then plugged into the leakage and outlet temperature correction equations that are pre-requisites to determining an air preheater's gas side efficiency and x-ratio.

6.10 SYSTEM AIR IN-LEAKAGE

There are two ways to measure air in-leakage:

1. The first method is to perform flow-traverses at each location to compare the increased mass flow from point to point.
2. The second method is to measure the oxygen rise from point to point.

As more air infiltrates the flue gas, the O_2 percentage will rise closer to the ambient oxygen level of 20.9 percent. Once the percentages have been calculated, flow will only need to be measured at the various locations. Or, by measuring flow at one location, the flow can then be back calculated for each location based on the percent leakage. O_2 Rise and/or System leakage can be calculated by measuring representative oxygen values at various locations. Some examples of a supercritical unit measurement location are shown in Figures 6-66 and 6-67.

Common locations for air heater performance testing on one 600 MW Indian supercritical unit are illustrated in Figure 6-66.

Figure 6-66: Boiler Exit and Air Preheater Testing Locations

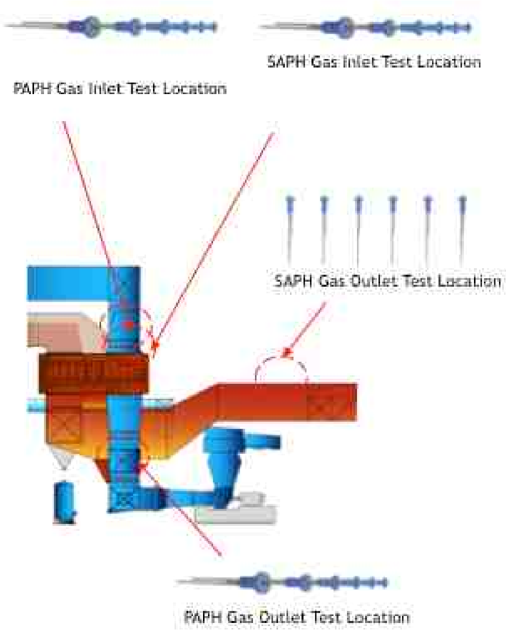
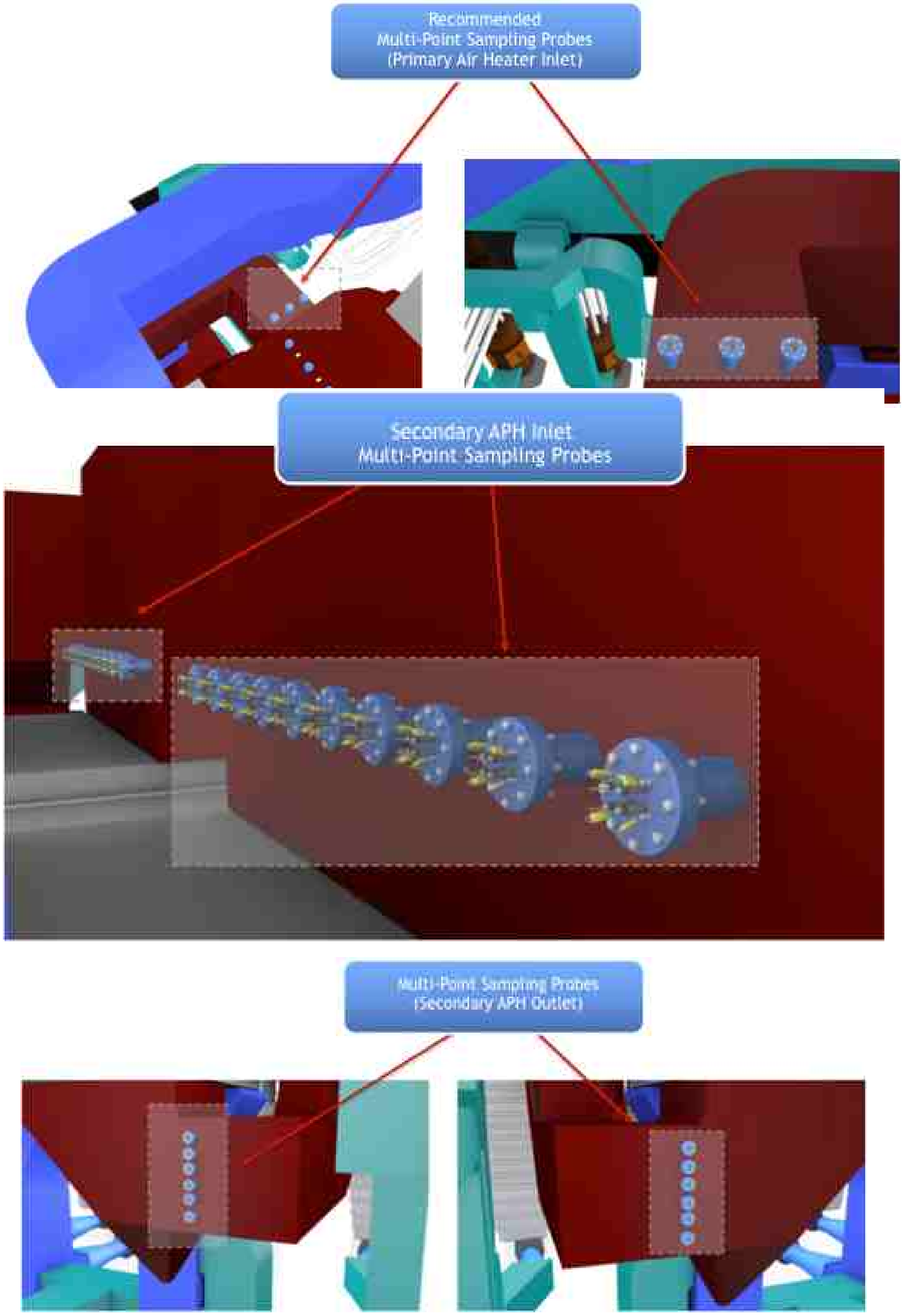


Figure 6-67: Recommended Locations of Multi-Point Sampling Probes



Understanding Flue Gas Flow

- Comparison of flue gas rates with the expected fuels fired and/or oxygen rise can validate any concerns with system air in-leakage.
- Should be noted that all of the air pollution control (APC) equipment are designed and tuned for a given volume of flue gas for treatment.
- Changes in flue gas volume with temperature, moisture or leakage impact the performance of the APC equipment.

Usage of Infrared Technology (IRT) for Air In-Leakage Detection

IRT is an effective technology for quick and convenient diagnosis of air in-leakage in Condenser and associated system as well as Boiler areas operating at below atmospheric pressure. IRT helps in detection of specific fault location facilitating availability and efficiency improvement [16].

Advantages:

- Quick and convenient method for air-in-leak detection of various components of a boiler or turbine cycle systems. (i.e., condenser, LP turbine, APH, second pass ducting, expansion joints, etc.)
- Online and non-intrusive technology.
- Ability to detect minor leakages and their specific locations in Boiler and Turbine area such as seals, Man holes, LP Turbine parting plane, Bolts, Sampling points, Welding joints of valves, LPT Glands, etc.
- Application facilitated by present IRT technology and handheld cameras with advanced features.

Detection of air-in-leakage in turbine (condenser and LP turbine) and boiler area (APH, economizer, ducts, etc.) is a big concern for power plant engineers. Air in-leakage in a condenser is one of the common reasons for poor vacuum and heat rate. Therefore, Infrared Thermography (IRT) can be used to identify the location of air-in-leak in condenser, LP turbine and boiler areas operating at atmospheric pressure. It is also useful in detecting locations of air-in-leaks in negative pressure vessels, pipes and ducts. It is more useful in detecting minor leaks and pin point the exact location of air in-leakage, but is not successful in those areas that are insulated, or not in line of sight.

It detects broad areas of air-in-leakage and is very useful in detecting air in-leakage at the points which are not in the line of sight or inaccessible. It has limitations of not being able to pin point the exact location of air-in-leak. "Acoustic" is another technique being employed for this purpose. Generally it is used as a complementary tool along with some other technology. "Infra-Red Thermography", "Ultrasonic/Acoustics" and "Helium" all are helpful in detection of air ingress location points. When combined together, the effectiveness of these leak detection methods increases. It reduces error of measurement and increases reliability of result.

Concept of IRT Technology

In negative pressure areas air ingress takes place and is detected by fall in temperature at the ingress location as "Cold spots". Air being cooler, in turn cools the edges of leakage areas. Temperature of the edges at leakage points is cooler than the surrounding. The cooled edges are identified by the temperature differential.

IR Thermography is a non-intrusive method of gathering and analyzing diagnostic information concerning the thermal pattern of a piece of equipment. All objects radiate energy. The IR detector receives the energy proportional to the fourth power of temperature (Stefan-Boltzmann law). Even a small change in temperature produces a large amount of radiant energy. Detectors can "sense" this infrared radiant energy and produce thermal images. Each thermal image ("thermograph") represents the thermal pattern and displays temperature in color or grey scale [16].

Figure 6-68: Example of Thermal Imagery of a Parting Plane [16]

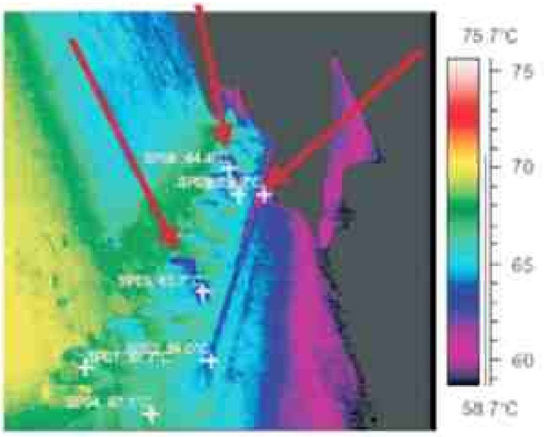


Photo Credit: CenPEEP, NTPC

LPT Parting Plane with Air-In-Leak Locations

Air-in-leakage is observed from LPT parting plane surface and bolt edges (shown by arrow in Figure 6-68). Temperature differential of approx. 6-7°C was observed on the surface of parting plane. Bolts have also slight air- in-leaks. Two bolts shown by arrow have an air in-leakage. A temperature difference of 3-4°C was observed at bolt edges. As a corrective action sealant was applied to arrest the air-in-leak from the parting plane surface after IRT survey. Unit loading was restricted to 25 MW, which could be increased to 35 MW due to improvement in condenser vacuum (an improvement of 10 MW).

Hot Well Manhole

View of a CEP Suction Strainer Flange

Figure 6-69: IRT Images [16]

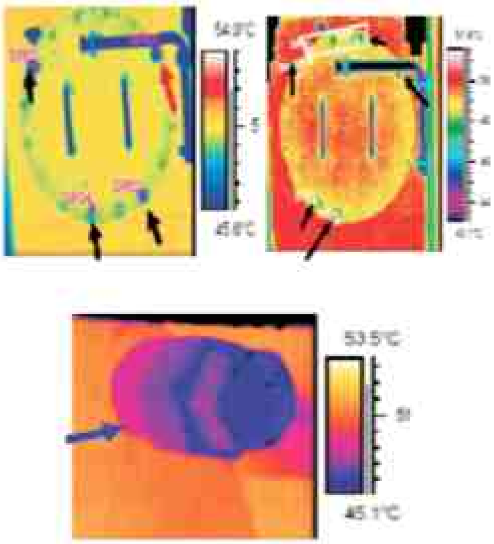


Photo Credit: CenPEEP, NTPC

Air In-leakage locations at Manhole A and B were maintained at that value even after one hour of running the pump. Before identification of these leak locations and corrective action, the dissolved oxygen levels were 110-120 ppb.

Key Elements for Ensuring Reliability

- Preserving functionality of equipment ensures reliability.
- Identification of failure modes and their mitigation is the key.
- "As found condition" during preventive maintenance, overhauls is important input for failure causes.
- Predictive maintenance (PdM) is a cost effective strategy.
- 3D's: Detection, Diagnosis and Documentation are essentials of PdM.
- Reliability and integrity of data is vital.
- Use of multiple technologies and integration of all data is critical for interpretation.
- Training of personnel in diagnostic techniques is important.
- Establishment of root cause helps in eliminating the repetitive failure.

6.11 IMPORTANCE OF COMBUSTION OPTIMIZATION WITH SUPERCRITICAL BOILERS

The overall performance, operability, load response, reliability, and capacity of all the unit's components are all inter-related. The evaluation and sustainable control of major pollutants must include understanding of a unit's boiler condition, fuel quality variations, firing system equipment condition, soot blowing equipment, air-fuel measurement equipment, instrumentation and the overall steam cycle performance.

Considering that supercritical units operate at higher pressures and temperatures than a subcritical boiler, the transfer of energy through the system and boundaries are very interrelated with one another. At supercritical pressures and temperature, the increased efficiency reduces fuel consumption with the thermodynamics of expanding higher pressure and temperature steam through the turbine and has been largely responsible for their “better than average” fleet efficiency and heat rate consistently throughout their operation.

As with any steam generator, the boiler and its auxiliary equipment can be considered a series of heat exchangers or several components transferring energy through the system. Understanding the total energy distribution or “heat distribution” through the system is especially important with supercritical units which are operating above the critical pressure of 221 bars (3,208 psia). Operating at or above this pressure results in conditions where the water and saturated steam are in single phase. Therefore, for those not familiar with supercritical boilers, this means that water enters in on one end and leaves as a supercritical fluid on the other end (no steam drum or circulation). If minimum flows are not maintained, boiler tube failures can and will occur. The water and steam flow circuitry with supercritical units is different from subcritical units and the complex mechanical conditions and water purity requirements demand increased attention. Because of this and an aging work fleet of equipment and people, system evaluations and optimization techniques are of paramount importance for achieving low cost and sustainable power generation.

Also, one cannot forget that environmental performance is linked to boiler reliability (largely from tube leaks, fouling, and slagging) and can be impacted negatively by non-optimal combustion, and consequent tube metals and/or boiler casing overheating, while power generation cost or production costs can be largely influenced by fuel flexibility options, heat rate, and condition of the plant operating equipment. Considering this, it is important to understand that combustion efficiency, reliability and air pollution control are all very much inter-related. To put this in perspective, here are 21 examples of the inter-relationships:

1. Heat transfer through the furnace or convection pass can have a significant impact on the boiler exit gas temperatures. If lower furnace heat transfer is not optimized, the furnace exit gas temperature can result in performance challenges such as forced outages due to overheating of the upper furnace tube circuits and/or accelerated air infiltration upstream of the excess oxygen probes that will result in oxygen deprivation in the furnace. When secondary combustion in the upper furnace occurs, the carbon is quenched on the screen tubes or convection pass inlet

tubes when the temperature drops to ~760°C (1,400°F) and the levels of CO, dioxins and furans are elevated due to the non-optimum destruction within the available furnace residence time.

2. Variations of fuels being fired also impact the combustion process as well as the performance of the firing system equipment The fuel constituents and preparation have a significant influence on the milling systems, slagging and fouling tendencies in the boiler, total flue gas volume, combustion quenching on the boiler tubes and ultimately impact the formation of major pollutants such as NO_x, SO_x, CO, Dioxins and Furans (as previously noted).

3. Combustion and the ash fusion variables for coal ash are very much inter-related and thus with low NO_x firing in a utility furnace, operating at near stoichiometric conditions can be problematic in regards to slagging or water wall wastage. This is especially true when firing coals that have high concentrations of iron in the ash. With these fuels (or any fuel), they should be burned in an oxidizing atmosphere where sufficient air is provided for complete combustion. If insufficient air is provided in the furnace and/or localized areas of the furnace, the fusion temperature of the ash in this "reducing" atmosphere can be lowered by as much as 204.4°C (400°F) leading to potential slagging within the boiler.

4. If the fires are impinging the sidewalls in a reducing atmosphere, not only can this contribute to slagging problems, but also corrosion and wastage of the tube surfaces. This impacts the overall heat transfer of the system and often yields uncontrolled "lower furnace" combustion that impacts sustainability and control of emissions at the back-end if controls, monitoring and tuning is not proactively employed.

5. If installed, de-activated SCR catalysts, NH_3 slip and/or sorbent injections for SO_3 control can accelerate common issues that often include fouling, plugging and/or corrosion of the air preheater. Also, keeping in mind that air preheater performance and reliability is often influenced by the upstream performance of the boiler.

6. If air preheater thermal performance is non-optimal, the end result is commonly identified with non-optimal temperature gradients, velocities and increased gas volume exiting the gas outlet ductwork also being digested by the Air Pollution Control (APC) equipment.

7. Any flue gas diluted with air leakage on the cold end of the air preheater will lower the overall gas outlet temperature as well as change the temperature gradients downstream from the air preheater outlet. Furthermore, it must be understood that high air in-leakage results in lower gas outlet temperatures and when combined with $S0_3$, accelerated corrosion is likely to occur.

8. Regenerative air preheater "air to gas" ratios and pressure variations have a major impact on regenerative air preheater performance. Considering this, it must be noted that the mechanical condition of the air preheater and minimization of air to gas leakage is vital for the health and overall plant performance. Furthermore, it must be understood high air in-leakage results in lower gas outlet temperatures and when combined with $S0_3$, accelerated corrosion is likely to occur.

9. There are numerous boiler operational parameters that can influence SO3 formation. These variables are fuel sulfur content, ash content and composition, convective pass surface area, gas and tube surface temperature distributions, excess air level, firing mechanism and coal fineness.

10. SO_3 combines with flue gas moisture to form vapor-phase sulfuric acid at temperatures below about 315.5°C (600°F). Therefore, any sulfuric acid in the flue gas can lead to power plant operating problems. These problems can include boiler air preheater plugging and fouling, corrosion in the air preheater and downstream ductwork/equipment. To prevent the condensation of the SO_3 (and thus limit formation of sulfuric acid) the exit gas temperature coming from the air preheaters must be kept above the dew point of the sulfuric acid. The higher required exit gas temperatures translate directly into a loss of system efficiency, which imposes a significant heat rate penalty. However, the more SO_3 formed, the higher the dew point. The sulfuric acid dew point temperature depends on the SO_3 and water vapor concentrations in the flue gas. Higher concentration of either species raises the acid dew point temperature.

11. Leakage control in conjunction with the control of sulfuric acid (H2SO4) is especially important when managing flue gas that is a byproduct of high sulfur fuels. This is considering that when SO_2 is oxidized into SO_3, the SO_3 readily combines with water vapor to form H_2SO_4 (sulfuric acid). Oxidation of SO_2 occurs from contact with heat transfer surfaces – the metal in the boiler acts as a catalyst – and also from contact with the catalyst in selective catalytic reduction (SCR) systems.

12. While a significant portion of the SO_3 will condense on ash particles and be collected along with the fly ash, the non-condensed SO_3 can have significant side effects. Excess SO_3 leaving the stack can result in a noticeable "blue plume", which consists primarily of sulfuric acid that has condensed into tiny droplets. Those same droplets may also condense on the cold end of the air preheater, or in the downstream ductwork causing corrosion and plugging. In addition, excess SO_3 can combine with ammonia slip from an SCR system to form ammonium bi-sulfate (ABS) which has a notorious reputation for plugging air preheater heat transfer element. Essentially, the excess ammonia combines with excess SO_3 and water vapor which starts to condense on the air preheater element surfaces at temperatures below about 230°C (450°F).

$$NH_3+SO_3+H_2O \rightarrow NH_4HSO_4$$

The ABS plugging also impacts the distribution of the air and flue gas while also elevating air to gas differentials and leakage (as a result of the elevated pressure drop across the air preheater).

13. In an effort to remove excess SO_3, dry powder or water slurry mixes of alkaline sorbents (i.e. hydrated lime, limestone, magnesium oxide, sodium bisulfate and trona) are sometimes injected upstream or downstream of regenerative air preheaters. While these chemicals are quite effective in adsorbing excess SO_3 and reducing blue plume and corrosion, the effect of these sorbents on the air preheater can be an issue if plugging occurs with a non-optimal injection process.

14. Non-optimal boiler and combustion performance results in degradation of nearly all APC equipment, including - SNCR, SCR, Dust Collection Systems (ESPs/Bag houses) and FGD systems.

15. If the ash concentration or gas velocity in any of the passages near the collecting electrodes on an electrostatic precipitator (ESP) exceeds the design gas velocity, collection efficiency will decrease.

16. Variations in particle sizing, flue gas distribution imbalances from the air preheaters or gas distribution equipment, High carbon in ash concentrations, temperature, sodium and/or other chemical compounds in the coal ash all have a major influence on ash resistivity and/or overall ESP collection efficiency.

17. When boiler tubes are fouled, it is from constituents in the coal. For example, sodium vaporizes during combustion and then condenses on tube surfaces and then fly ash particles stick to the surface and harden as they accumulate. After this occurs, pressure drop increases, fan capacity decreases and soot blowing demand increases.

18. Soot blowing schedules often require adjustments based on coal quality and load control. If not properly blown, steam temperatures tend to drop and the boiler tubes are covered with ash and thus resulting in a loss of heat transfer while also creating additional pressure drop across the system.

19. While ash deposition rates are primarily associated with chemical composition of the coal ash, operating practices with proper soot blowing can help control accumulation and the previously noted pressure drop on the system. Proper inspection and maintenance practices can improve the reliability from soot blowing, which is often a primary culprit for forced boiler outages.

20. If air preheaters are not kept clean and/or optimized for thermal efficiency, the gas temperature leaving the heater will rise and air temperature can drop as the heat transfer surfaces get fouled. Conversely, if air in-leakage is excessive, ash deposition, plugging and dew point/acid corrosion problems can occur.

21. Limitations in power generation are often related to exhausted fan capacity due to excess pressure drop related to problems in the boiler and/or combustion efficiency.

Understanding Combustion in a PC Fired Unit

In a typical pulverized coal-fired unit, there is only about 1-1.5 seconds of furnace residence time to complete combustion. Within this short residence time, it is important to complete the combustion of carbon and hydrogen (variables which produce heat) within the lower furnace (often referred to as the burner belt). When the air and fuel is mixed well and above the minimum combustion temperature of carbon, for every molecule of carbon, one molecule of carbon dioxide (CO_2) is formed and heat is produced. Incomplete combustion is when there is insufficient mixing before the products of combustion are quenched or inadequate oxygen to combine with all of the carbon and hydrogen to form CO_2 and H_2O. Incomplete combustion results with flame carry-over into the furnace exit, when not all of the chemical energy of the fuel is converted to heat, thus lengthening the flames and reducing efficiency. This results in a hazy furnace, measurably high CO, higher gas temperatures leaving the boiler, increased slagging, etc. It also contributes to boiler exit flue gas temperature being too high, and therefore, can contribute to superheater tube overheating, superheater, and boiler generating bank tube plugging.

Oxidizing hydrocarbons and completing the combustion of carbon char prior to the furnace exit also improve lower furnace absorption and reduce the bulk furnace temperature and slag propensity in the upper furnace. When combustion is non-optimal, carbon becomes de-volatilized carbon char and often results in elevated secondary combustion in the upper furnace where carbon is quenched on boiler tubes.

Once the combustibles and flue gas enters the upper furnace and convection pass and reaches a window of 760°C (1,400°F) to 871°C (1,600°F), no further oxidation of carbon occurs. CO is a good indicator of difficult-to-monitor concentrations of partially oxidized organic compounds. The inter-relationships of combustion, efficiency, reliability and control of major pollutants on supercritical units must be considered when evaluating the long-term sustainability of plant performance and air pollution control simultaneously.

Burner Design and NO_x Control

The burners are the mechanism that mix the fuel and air and then ignite them for combustion in the furnace. Ideally equal amounts of fuel and air are divided among the different fuel lines. Keeping this balance requires optimal mechanical tolerances on all burner components. Also proper combustion airflow measurement for supplied airflow is essential [17].

In the case of pulverized coal units, primary air is used in the mill to help transport, classify, and dry the coal. The minimum operating condition for the burner is usually limited to the turn down ability of the mill. The primary air to fuel ratio depends on the minimum airflow required.

The minimum airflow set point is a function of the fuel line velocity and then controlled to a fuel feeder output after the minimum airflow set point is established.

Secondary air is mixed with the fuel and primary air at the burner. The amount of secondary air depends on the amount of primary air used, coal quality and the amount of over-fire air being utilized higher in the boiler.

Proper burner sizing (typically based on the design fuels) is important to develop the proper and effective flame shape and intensity. Flame characteristics depend heavily on air and fuel staging within the burner and the amount of mixing that takes place. If the primary air velocity is too high, the flame can detach from the burner or blow out completely. This is especially true with low volatile domestic Indian coals.

Alternatively if the velocity is too low, the desired flame shape is difficult to maintain and burner overheating or wind-box fires are a possibility. Lack of maintenance and care for the firing systems and/or attempts to use adjustable fuel line orifices, without an integrated measurement program can result in plugged fuel lines and devastating impacts if improperly managed.

The design for good combustion burners has changed with the implementation of nitrous oxide emissions caps. High turbulence, short flame burners do a good job of quick, efficient heat release. However, the same attributes that make the burner good for combustion also make it good for high NO_x production. Depending on the manufacturer, the design intent and the coal being burned, burners can take many different shapes and sizes.

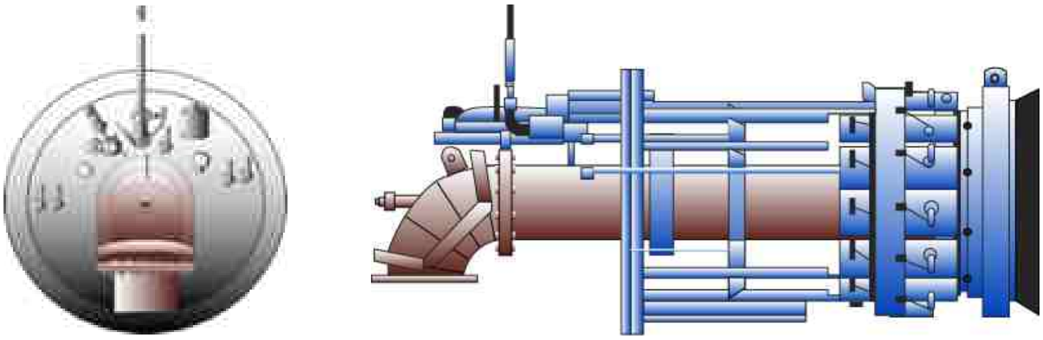
Sometimes the misconception that a burner design that worked well at plant “A” will also work well at plant “B.” There have been situations where low NO_x burner designs failed because of improper specification with the “as-fired” fuels. This is considering that as low NO_x burner designs evolved, the flame shape got longer and narrower with ever increasing levels of air staging. This creates a cooler less turbulent flame that is more NO_x-friendly, but less intensive. Lower intensiveness from the heat output can quickly allow the volatiles in the fuel to devolatilize and end with combustion taking place in the upper furnace. Again, this is especially true with low volatile fuels such as those domestic to India. Low volatile fuels demand adequate time, temperature, and turbulence. This is often referred to as “the 3-T's” of combustion.

Time: How fast the heat is released (as opposed to the slow release of N_2).

Temperature: The intensity of the flame and heat (Taking into consideration the thermal NO_x threshold and fuel factors).

Turbulence: The mixing or turbulence to promote the above.
Example of a very common low NO_x burner for a wall-fired boiler is shown in Figure 6-70.

Figure 6-70: Typical Low NO_x Burner



On this type of burner, there are air adjustment vanes which help to better mix the air for a good controlled burn. However, with the evolution from high intensity burners to less intense low NO_x burners, this means there are more mechanical linkages, dampers, and dimensional changes at the burner, which create further challenges when burners are left out of service for extended periods of time or not periodically stroked and cleaned of ash.

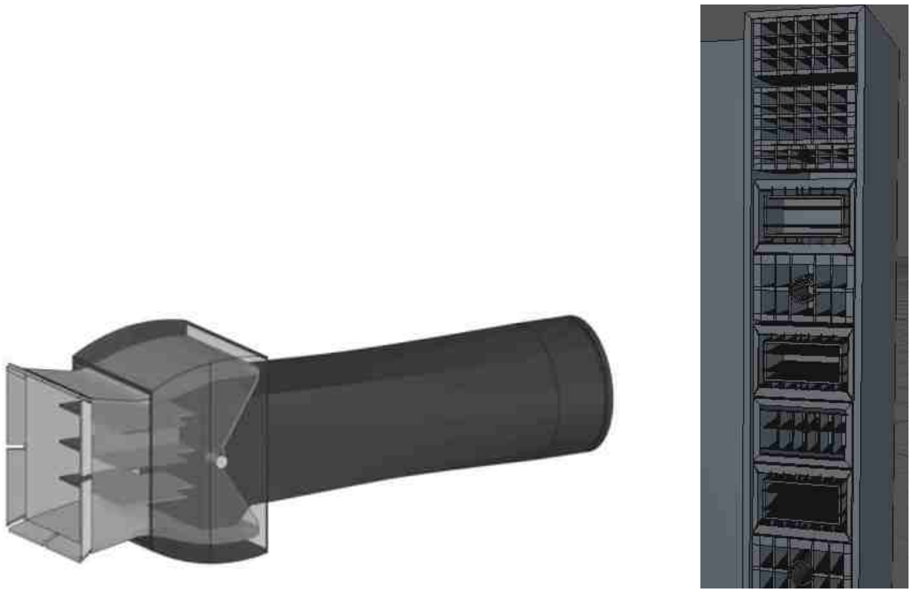
An ultra-low NO_x burner, such as the one shown in Figure 6-71, has four paths of air delivery for combustion staging. The air acts as a blanket between the fuel rich center and the lean outer edges of the flame helping drive off more fuel bound nitrogen as diatomic nitrogen before it can convert it to nitrogen oxide in the combustion process. As can be seen, the diversion of air away from the centralized coal nozzle and without a fuel mixing apparatus results with less intensity, but improved NO_x control. However, one of the major challenges for the low NO_x burner's mechanical integrity is when the burners are not maintained or removed from service and exposed to the radiant heat from the furnace.

An alternative to wall firing is corner firing or tangential firing (Figure 6-72). This approach effectively turns the entire furnace into one large burner. The center becomes a fuel rich zone while the outside is air rich. This allows the fuel to burn out at a slow pace that is good for NO_x This configuration is also more forgiving in regards to fuel and air imbalances. The burners are placed at each corner and angled inwards. The air supply nozzles are then located in between the coal nozzles. The number of nozzles and ports depends on the size of the unit and how many burner lines are present.

6-71: Ultra Low NO_x Burner with Four Air Zones

This type of burner has the primary air/fuel mixture coming through the center of a square shaped nozzle with secondary air on the outside edges. These burners are also capable of tilting to adjust for different firing conditions. By adjusting the tilts, one can move the position of the fireball. This feature is designed for reheat steam temperature control at low loads.

Figure 6-72: Tangentially Fired Burner Assemblies



Left: Typical corner fired "Bucket" or coal nozzle and
Right: “face view” of burner corner with both fuel air and auxiliary nozzles shown

Combustion Control

Typically, a good indication of proper secondary airflow and/or air/fuel ratios is the ignition point of the fuel. Boiler operators should be trained on what is considered acceptable ignition points, as observed with acceptable mill performance and post outage testing/tuning.

Generally the initial ignition of the fuel should be no more than one meter from the front face of a burner nozzle depending on mill loading, and the ignition should be stable. If ignition points are further than one meter, it's likely that the secondary air supply is inadequate or that the fuel is out-running the air because of a high air-fuel ratio.

Ignition points are often difficult to observe when all mills are in service. However, clearer observations are possible as mills are removed or placed into service. Combustion airflow staging with damper control influences burner shape. However, it is also important to ensure adequate flow and particle sizing of the fuel when firing solid fuel.

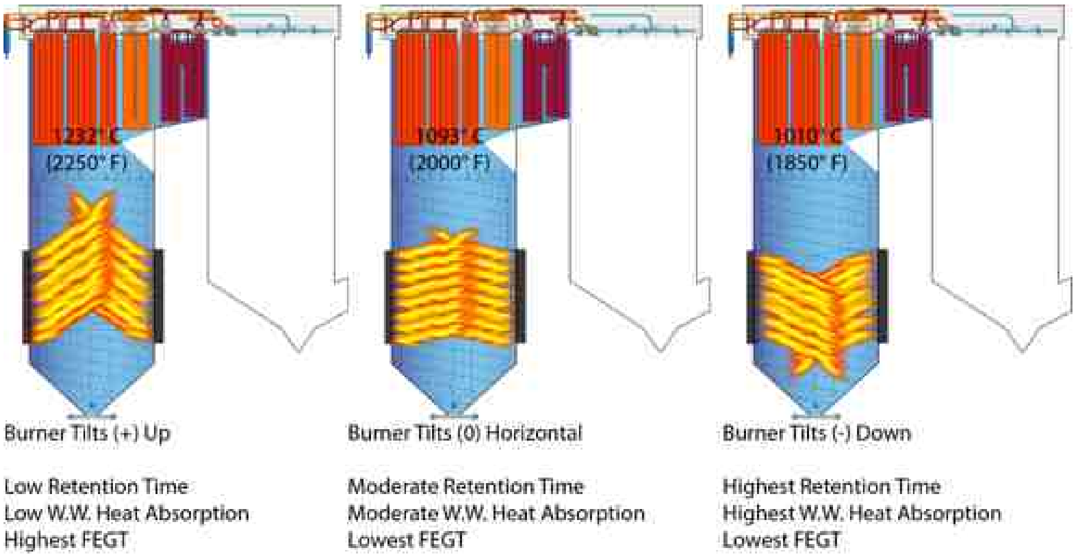
In order to ensure adequate pressure distribution within the wind-box, the air dampers must also be used to modulate for maintaining an optimal wind-box-to-furnace differential set point. This is a very important task.

Mill biasing can also be an important component for optimizing difficult fuels and/or when some mills have sub-standard performance. Poor fineness can also be expected when operating mills over their capacity, or with worn-out components. Also, running mills light and with inherently high air-to-fuel ratios can result in non-optimal performance. On vertical spindle mills, the grinding elements must be loaded uniformly, equalizing force and having optimal residence time for grinding efficiency by controlling the air-fuel ratios.

On tangentially fired units, which are very common in India, the tilts need to be periodically stroked up and down (+20/-20). This helps to break up any small slag accumulations that may collect around the nozzles and prevent seizing of bearing components. Control of the tilts should also coincide with optimal and intelligent soot blowing and the control of furnace exit gas temperature. This is considering that tilt position on T-fired units can have a major impact on residence time and Furnace Exit Gas Temperature (FEGT) at the boiler exit [17].

Figure 6-73 illustrates non-optimum vs. best performance with tilt position results.

Figure 6-73: Tilt Position vs. FEGT



6.12 AUXILIARY POWER CONSUMPTION

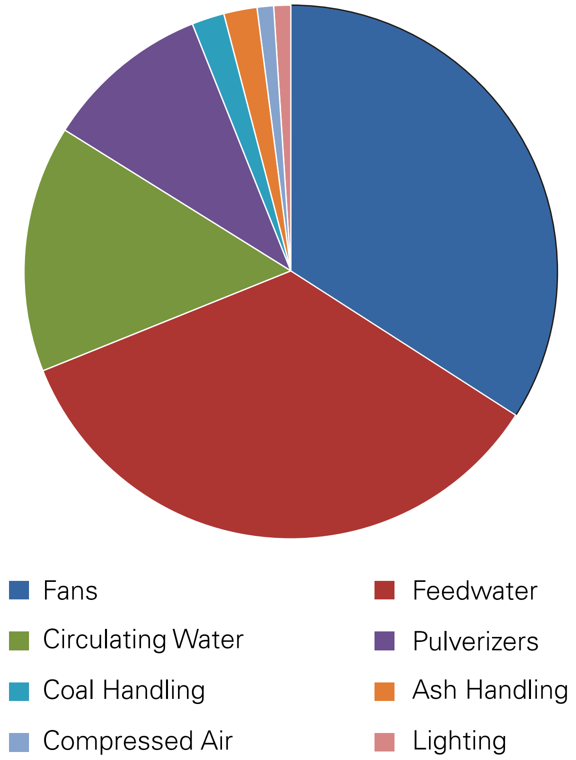
Considering the concerns for climate change and the onset of new pollution regulations, many power plants are increasing auxiliary power usage with the addition of pollution control equipment. Additions and/or modifications of such equipment that includes electrostatic precipitators (ESP), fabric filter (FF) bag houses, flue gas desulfurization (FGD) systems, fans, pumps, and the respective electrical systems can significantly impact auxiliary power consumption. With new plants, additional cooling water pumping demands are required to meet environmental discharge rules. Furthermore, there has been a trend away from mechanical (i.e. condensing steam turbine) drives and towards electrical motors as the prime mover for plant auxiliary pump and fan drives.

With pulverized coal-fired power plants, the auxiliary power demands can vary from 7-15 percent of a generating unit's gross power output. Older PC plants with mechanical drives and fewer anti-pollution devices had auxiliary power requirements of only 5-10 percent. With supercritical units, the increased feed water pumping power demand is much greater than that of drum boilers. This increased demand in auxiliary power represents a real loss and increases net plant heat rate, limiting the overall plant's generating capability. A plant's design, performance, equipment and efficiency are very much related to the site's ambient conditions, supplied fuel quality, mechanical conditions and the operational settings and performance of the unit.

Automation and control of auxiliary power consumption must be understood holistically and managed accordingly. Potential for improvement can be realized through performance benchmarking and implementation of best practices. Some of the best practices include: installation of automation, control improvements and energy efficient components. Performance benchmarking efforts have been done in the U.S., but through industry-funded organizations like EPRI [data collected from 2012 EPRI heat rate conference, Phoenix, AZ [20].

Table 6-5: Typical Auxiliary Power Consumption In Coal-Fired Power Plants	%
Fans	34%
Feed water	35%
Circulating Water	15%
Mills	10%
Coal Handling	2%
Ash Handling	2%
Compressed Air	1%
Lighting	1%

Figure 6-74: Typical Auxiliary Power Consumption in Coal-Fired Power Plants



Standardization efforts are best represented by IEEE Standard 762-2006, IEEE Standard for Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity [18].

Reducing auxiliary power and conducting periodic audits help improve overall efficiency, heat rate, and plant emissions.

6.13 ONLINE PERFORMANCE MONITORING AND ANALYSIS

Along with supercritical boiler technology advancements, there have also been significant industry best practice improvements with process and control instrumentation used for online monitoring.

Online performance tools with an integrated thermodynamic model, calculations and trending capability are commonly being used for "real-time" evaluations of various component and overall power plant performance. Monitoring can be used for the purpose of heat rate management, plant aging, life cycle analysis and overall benchmarking.

In Section 6.3, various technologies for online coal analyzers were discussed. Considering that coal properties have a major influence on performance and emissions, trending and understanding the performance impacts are imperative for both efficiency and dispatch optimization. Technological progress made with real time coal quality and performance monitoring equipment has resulted in overall efficiency improvement throughout the utility industry.

Modern instrumentation and processing power has provided capabilities for the improvements with managing solid fuel firing system inputs on large utility boilers. However, today the same challenges remain with calibration of equipment and distribution of fuel and air when it enters a furnace. Thus, understanding combustion, boiler cleanliness, heat absorption paths and flue gas distribution all demand attention to detail, along with intelligent process equipment and controls for optimization. This is especially true for those faced with load cycling, fuel quality variations, and stringent environmental regulations.

Ideally the analysis of a plant's equipment performance could improve reliability by detecting and rectifying failures before they occur. With online performance monitoring using validated, representative and functional feedback from the process instrumentation, plant assessments can be simplified and productive. This is important for execution of a holistic plant performance and preservation program. Integration of a unit's “inputs” such as coal quality, air-fuel ratios, thermal performance, heat transfer and emissions can be evaluated and proven very useful, if the operations team has the available feedback and knowledge base to react when faced with operational challenges.

Not all performance parameters impact plant performance equally. Thus, understanding Key Performance Indicators (KPIs) can serve as a guide for a plant performance and heat rate improvement program.

Some examples of important Key Performance Indicators (KPIs) are as follows:

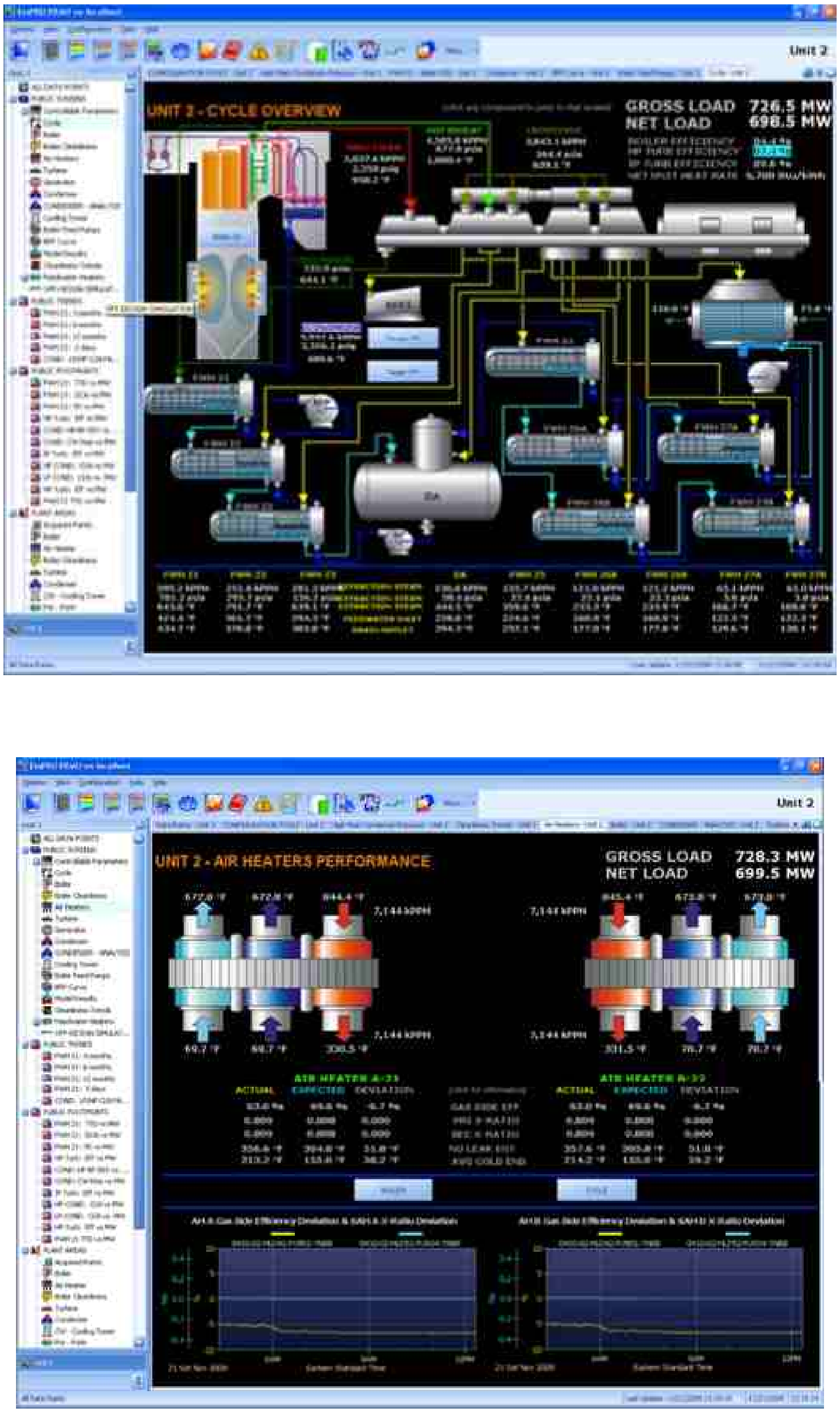
1. Condenser back pressure
2. Auxiliary power consumption
3. Turbine efficiency (LP, IP, HP)
4. Cycle losses due to leaky vents, drains or internal turbine leakage
5. De-superheating spray flows
6. Coal quality
7. Feed water flow
8. Steam flow
9. Make-up water
10. Unburned carbon in bottom ash and fly Ash
11. Flue gas temperatures
    - Furnace exit gas temperature
    - Boiler exit gas temperature
    - Air preheater exit gas temperature (corrected to no-leakage)
12. Main steam pressure

13. Main steam temperatures (SH and RH)
14. Feed water heater performance
15. Mill horsepower per ton consumption
16. Coal flow
17. Combustion airflow (all); stoichiometry
18. Excess oxygen/excess air
19. Deviation between combustion airflow and theoretical or excess airflow
20. Total air-fuel ratio
21. System air in-leakage
22. Soot blower effectiveness
23. Tube metal thermocouples - variations and acceptable ranges
24. Ambient conditions (i.e. air and water inlet temperatures)
25. Mill inlet primary airflow temperature
26. Mill outlet primary airflow temperature
27. Air and gas system draft pressure measurements
28. Air preheater heat exchange efficiency, x-ratio, leakage

Today, state of the art technology such as, Advanced Pattern Recognition (APR) is available for empirical database modeling, anomaly detection and diagnostics. Further application of state-of-the-art monitoring tools for online performance monitoring can not only help improve efficiency, but also load generation and reduce equipment failures. Coupling online performance monitoring with "hands-on" functional checks of the process measurement equipment with world-class thermal performance monitoring tools, can result in a very reliable, user friendly, expandable, and accurate system. Moving beyond traditional monitoring, improvements have also been made with abilities to monitor and plan for such things as power marketing activities, economic dispatch curves and fuel consumption. Furthermore, online performance monitoring can be used for benchmarking units before and after major overhauls to validate local testing, while also evaluating and benchmarking performance over time.

Performance and condition monitoring enable the ability to alert, detect, model, quantify, trend, report, and diagnose thermal plant performance deficiencies. Having the ability to filter and analyze the key performance variables over time are very important for communication between operations, engineering, and management personnel. Simply put, it's important to understand that every increase in power plant efficiency will result in improved power production. Therefore, even the smallest operational improvement can result in significant savings. As examples, a few GP Strategies, EtaPRO™ screen views are shown in Figure 6-75.

Figure 6-75: EtaPRO™ screen views



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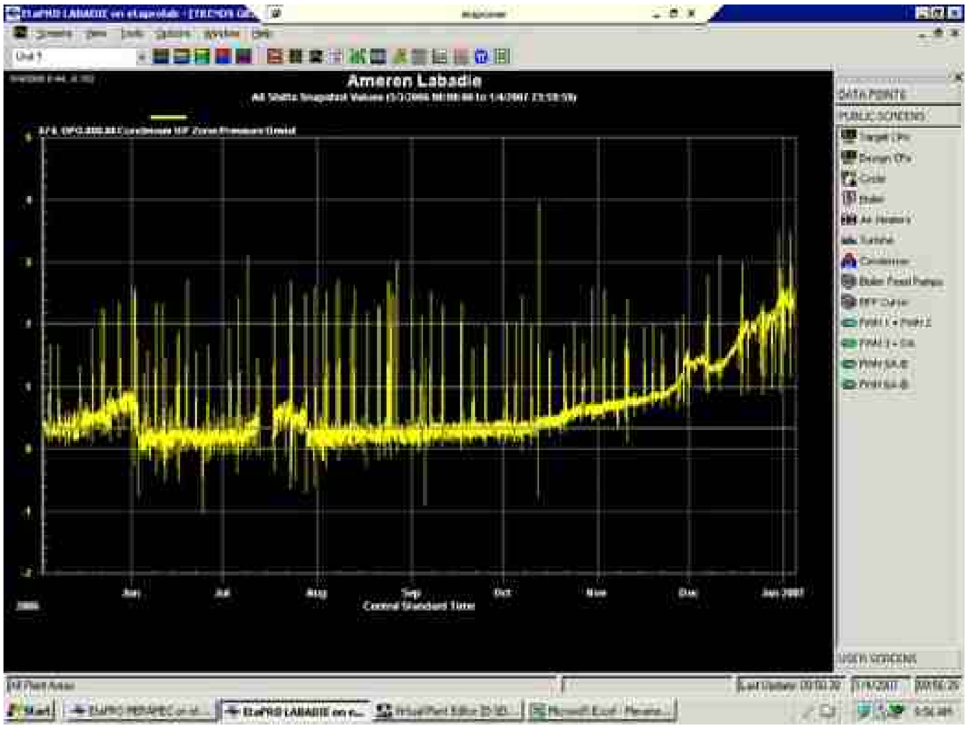
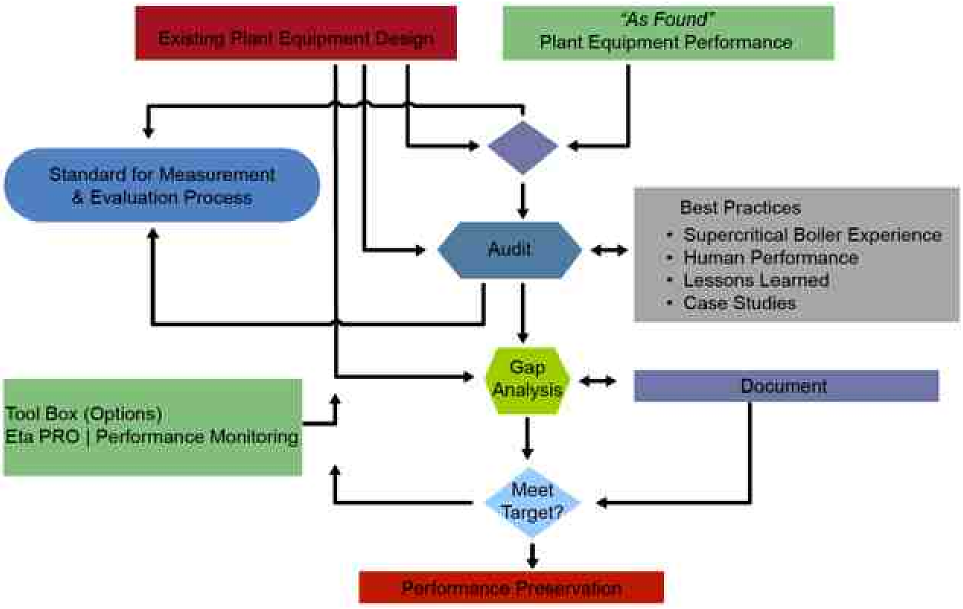


6.14 BENCHMARKING BOILER, COMBUSTION, AND PLANT PERFORMANCE

Creating action plans and organizing personnel to conduct performance measurement tasks are very important. Therefore having senior management involved, defined processes and division of responsibilities is key to a program's success. Other variables that are essential include the tools and equipment required to collect representative samples. They define the measurement process and best practices or tools required to identify and reduce gaps in performance. Performance preservation is a process that requires dynamic tools and process, grounded on fundamentals. One way to depict the previous process for a unit's evaluation is shown in Figure 6-76.

Figure 6-76: Plant Performance Management Process



Effective Plant Benchmarking of plant performance must be comprehensive.

- Periodic performance audits of the plant equipment, include:
    - o Boiler and Combustion Efficiency Evaluations
- Firing System Performance
- Stack Losses
- Unburned Carbon
- Dry Gas losses
- Losses from the "as fired" fuel
- Air Preheater Performance

- Corrected to "No Leakage" Exit Gas Temperatures
- System Air In-Leakage
- Air – Gas Pressure Drops and Flow Rates
    - Turbine Performance Testing
- Turbine Efficiency
- Turbine Losses
    - Cycle Isolation Checks
- Valve leakage
    - Feed water Heaters
    - Steam Generator pressure drop
    - Steam Path Audits
    - Evaluation of Controllable Losses
- Cycle Losses (i.e., Condenser, heaters, vents, drains)
- Boiler Losses (measured and stealth)
    - Cooling Tower Performance
    - Electrical Output Testing
    - Auxiliary Power Consumption Audits
    - Performance and reliability assessments to evaluate inter-relationships
    - Abnormal Start-ups
    - Start-up time
    - Air Pollution Control Equipment Operations (SCR, ESP/B-H, FGD, etc.)
    - Boiler tube temperature excursions
    - Boiler tube failures
    - Water chemistry tube failures
    - Equivalent forced outage rate (EFOR)
    - Capacity Factor
- Communication and Reporting of Results
- Performance and/or Strategic meetings
- Educational Training and Knowledge Transfer required to employ protocols and performance tests

Analytical Evaluations

The purpose of analytical evaluations is to compare actual vs. design and/or theoretical value by periodic checks and analysis. First and foremost, safe accessibility, lighting and cleanliness are required for all testing locations. The next step is to complete a comprehensive assessment of the plant's performance. Some analytical evaluations for consideration should include:

a. Minimum airflow calculation and review for the mills and fuel lines

b. Mill heat balance evaluations

c. Fuel loading curve development

d. Review of control variables:

    i. Evaluation of instrumentation deviations (if any)

    ii. Review of the plant equipment and design operating curves

    iii. Review all motor nameplates; operating parameters

e. Fuel analyses summary (current)

f. Review of the plant performance sheets and boiler design

g. Review of the “design” vs. “as found” performance

h. Review of all performance improvements completed to date

    i. Review of combustion performance

    i. Furnace exit gas temperature and carbon monoxide profiles

    ii. Airflow | Stoichiometric Firing Conditions

j. Efficiency and heat rate evaluation

k. Review of plant equipment issues (if any)

    i. For example:

        1. Coal feeders, Mills

        2. Soot blowers

        3. Boiler casing, expansion joints, and insulation

        4. Air preheaters

        5. Draft losses due to plugging and/or internal alignment issues

        6. Air and flue gas ductwork, Fans

        7. Controls instrumentation, Cycle losses

Plant Performance Management is a Cycle

Figure 6-77 shows the recommended approach taken by SSI to develop plant specific performance programs. Having a systematic approach to identify and communicate performance results is critical.

Figure 6-77: Boiler Performance Program and Cycle Example

(Stephen Storm, Inc. Initial Program Development Process)

After a program is developed, a plant-specific performance preservation program can be implemented. Such a program should include daily, weekly, monthly, quarterly and semi-annual objectives. Some examples of common checks that should be evaluated are shown on the following page.

Performance Preservation Example [10]

Daily – Weekly

- Normal operational checks, which should include the following:
- Airflow and Excess oxygen on curve
- Wind box to furnace pressure drop is optimum
- Feeders balanced and calibrated
- Mill airflow on a prescribed curve/ ideal air/fuel ratio (above the minimum air requirement)
- Damper strokes proper
- Steam temperatures optimum
- Spray flows normal
- Soot blower condition
- Soot blower effectiveness
- Balanced Combustion Airflow
- Air preheater temperatures
- Raw coal sizing (yard crusher output less than ¾" (19 mm))
- Burner air register settings
- Mill coal reject quantity
- Mill outlet temperatures
- Visual appearance of coal flames
- Nose arch and super-heater area for slag appearance
- Visual furnace checks for Boiler cleanliness and clarity
- Ensure Air preheater inlet gas duct hoppers not plugged
- Super heater and re-heater tube metal temperatures

Weekly – Monthly

- Soot blower effectiveness
- Fly ash sizing / analysis
- Coal Fineness (as feasible)
- Oxygen analyzer calibrations
- Damper stroke verifications; validate position by local indications
- Steam temperatures and spray flow measurements
- Furnace exit excess oxygen measurement

- Air preheater leakage
- Soot blowing steam temperatures and thermal drains

Quarterly – Semi-Annually

- Leak checks of airflow measuring elements (primary and secondary)
- Hot "K" calibrations of airflow measuring elements (primary and secondary)
- Furnace excess oxygen traverse by HVT probe to check oxygen and stratifications
- Measure oxygen rise from furnace to stack
- Refurbish grinding elements (this maintenance work should be driven by reports of accurate coal fineness results)

Each Outage (or as needed)

- Refurbish Mills
- Burner Condition
- Verify damper strokes (all damper to be verified from inside ducts)
- Leak check and repair sensing lines to airflow measuring devices and/or all other pressure measurement indicators used for control of the equipment and boiler performance
- Inspect and repair dampers as required
- Set air preheater seals, clean baskets, check and repair sector plates w/ all moving parts
- Inspect and repair all primary and secondary dampers and ductwork
- Thoroughly inspect and repair all ductwork and expansion joints
- Fan clearances and damper/inlet vane check

Developing a "Performance Driven" Plant Culture

Experience from the author is such that performance optimization starts with senior management. Having top management on board to develop and nurture a "performance driven" culture is essential to achieve "world class" performance standards. Some of examples are as follows:

- Safety must always be the priority
- Clear communication - there must be a process
- Establish the champions and division of responsibility (DOR)
- Combine the teamwork of the entire plant (Operations, Maintenance, Engineering, Management)
- Gain commitment from the team
- Cultivate opinions and create a responsible plant culture with a "let's go see" attitude

- Understand how to conduct troubleshooting and do it in a timely manner
- Encourage Knowledge Transfer and the deployment of "Best Practices"
- Conduct internal audits and stay on top of the low hanging fruit. Optimization is ongoing and must be implemented as an ongoing program. So, do not make it so complicated that it is not executed or understood.
- Harvest the low hanging fruit first by identifying the gaps and those which are controllable
- Plan the long-term recommendations accordingly and be driven by the data results
- Maintain good reports for all activities and details included
- Establish the frequency for functional checks and reports required
- Use the work smarter, not harder approach. As you continue through the benchmarking and asset management journey, testing and processes used for performance optimization should become easier and more "user-friendly."
- Management should create incentives and reward excellence
- Performance optimization is a never-ending cycle. Keep it up and work safely!

Turbine Cycle Performance Analysis 7.0

7.0 Turbine Cycle Performance Analysis

7.1 SUMMARY

Optimizing turbine cycle performance in a supercritical unit requires implementing best practices of both the turbine and all its associated equipment. The turbine cycle performance is affected not only by the turbine condition, but by the performance of the condenser, cooling tower, feedwater heaters, valves, etc. All of these are impacted by water chemistry, and operations and maintenance practices. Accomplishing world class performance requires learning and implementation of best practices. Many best practices are detailed in the body of this chapter that can help achieve the desired world class performance.

To improve the turbine heat rate requires first understanding the design basis of the turbine cycle and providing a way to know and track the deviations from design performance. Simply tracking the heat rate can be very deceiving, since it is impacted by seasonal conditions and peripheral equipment. This chapter provides means of trending deviations from design heat rate in a way that enables observing unit degradation, and tracking improvements.

Although tracking deviations from design heat rate enables better monitoring of unit performance, understanding the drivers of this performance requires quality monitoring of unit parameters. Modern instrumentation enables continuous monitoring and tracking of temperatures and pressures and enables utilizing those parameters to continuously calculate more complex information, such as turbine efficiency, heater Terminal Temperature Difference (TTD), condenser performance, etc. Tracking this information allows continuous improvement to the cycle heat rate.

Condenser performance can be optimized through several strategies. Some of these include monitoring strategies, equipment utilized, maintaining cleanliness through water chemistry, mechanical cleaning, and regularly evaluating the condenser performance. The best instrumentation available should be used to detect condenser tube leakage thereby protecting the cycle water chemistry. Instrumentation to detect the leaking tube in a timely effective manner is presented in this section.

Optimal design, operation, and monitoring of heaters are presented to provide the means to operate the heaters in a reliable, efficient manner that also maximizes generation and minimizes its cost. Means to monitor the heaters and implement practices that minimize cycling of heaters, and maximize performance are also included. The best practice described within this section details a technology to improve heater reliability and extend heater life as end-of life is approached.

The cooling tower provides the interface of the cooling water with the environment. Degradation in its performance prevents the condenser and turbine from attaining optimal performance. Ensuring effective performance of a cooling tower requires monitoring the thermal performance of the equipment. However, the key to attaining consistent cooling tower performance requires developing and maintaining a quality water chemistry program. The biological activity is the initiating mechanism for fouling of high efficiency fills. The parameters for monitoring water quality and the equipment that can provide this monitoring is described in this chapter. Indexes that monitor the biological activity and water quality and the criteria for control are also provided along with methods that can be employed to monitor and inspect tower film fill for fouling. Tests to measure tower performance and the penalties that are incurred are included.

Operating turbines in a cost-effective manner while maximizing reliability requires a quality turbine maintenance program. Inefficient turbines can significantly impact the unit heat rate, which impacts the fuel cost. Implementing a quality condition-based maintenance program that regularly evaluates unit operation can extend the duration between outages and cost-effectively recover those losses. Protocols to accomplish these tasks are presented. Guidelines for both online and outage-based assessments are provided. Inspection and sampling are included as an integral part of an effective auditing program. Turbine repair practices including processes for both modular repair and individual part repair are described.

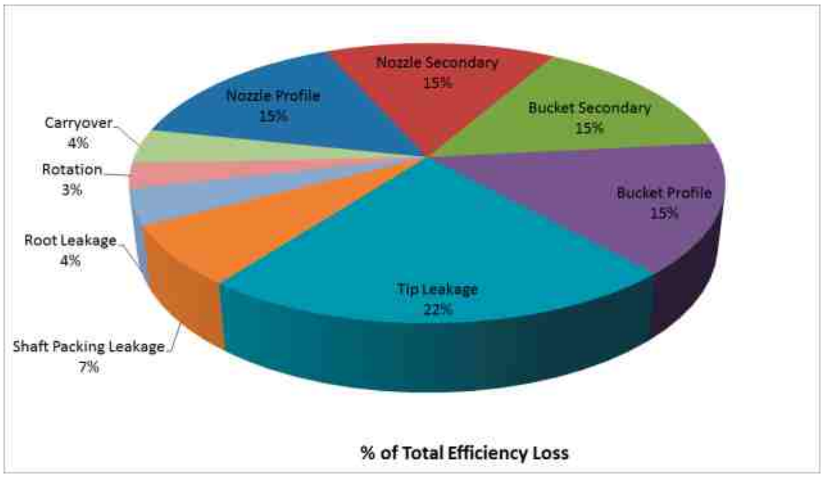
These comprehensive best practices for maximizing turbine performance facilitate reliable cost-effective operation of turbines

7.2 MONITORING TURBINE CYCLE EFFICIENCY AND HEAT RATE

Supercritical plants are typically large in size with high unit MW output and as such, operation at less than design efficiency can result in significant loss in both energy and financial resources. It is therefore very important to measure turbine cycle efficiency and heat rate in a timely, accurate, and continuous basis. The experience of the authors is that one percent main steam temperature error can result in over USD 400,000 of fuel cost per year on a large supercritical unit. Historically, cycle performance was only measured periodically utilizing test equipment in conjunction with performance test codes. But with the advent of precision instrumentation and plant monitoring systems, cycle performance can be monitored on a continuous basis. This practice enables early detection of unit efficiency loss, which translates into significant loss in plant profitability as well.

The thermodynamic performance of a steam power plant depends on many factors including cycle arrangement and inlet and exhaust steam conditions. However, the dominant contributor to the overall power plant efficiency is the steam turbine itself. The thermodynamic and aerodynamic performance of the steam turbine is primarily determined by steam path components, including the valves, inlet, nozzles, buckets, steam leakage control devices, and the exhaust. To maximize power plant efficiency, aerodynamic and steam leakage losses in the turbine steam path must be minimized in both the rotating and stationary components. Figure 7-1 shows the types of efficiency losses that occur in a typical turbine stage and the approximate percentage that each type contributes to the total stage loss.

Figure 7-1: Typical HP Turbine Stage Efficiency Losses



leakage losses account for roughly 80-90 percent of the total stage losses. Nozzle and bucket profile losses can be significant if the blade shapes are not optimized for the local operating conditions. Profile losses are driven by surface finish, total blade surface area, airfoil shape and surface velocity distributions, and proper matching between nozzle and buckets to minimize incidence losses [1].

A primary cause of steam path efficiency degradation in units with high temperature inlet stages >482°C (900°F) is solid particle erosion (SPE) damage. The steam path degrades as the nozzles and buckets are worn away by the passage of steam contaminated with iron oxide particles exfoliated from the inside surfaces of boiler tubes and main and reheat steam piping. The damage results in reduced steam path efficiency, lost power generation, shortened inspection intervals, and costly repair and replacement of damaged components [1].

Continuous Monitoring

Operator controllable losses

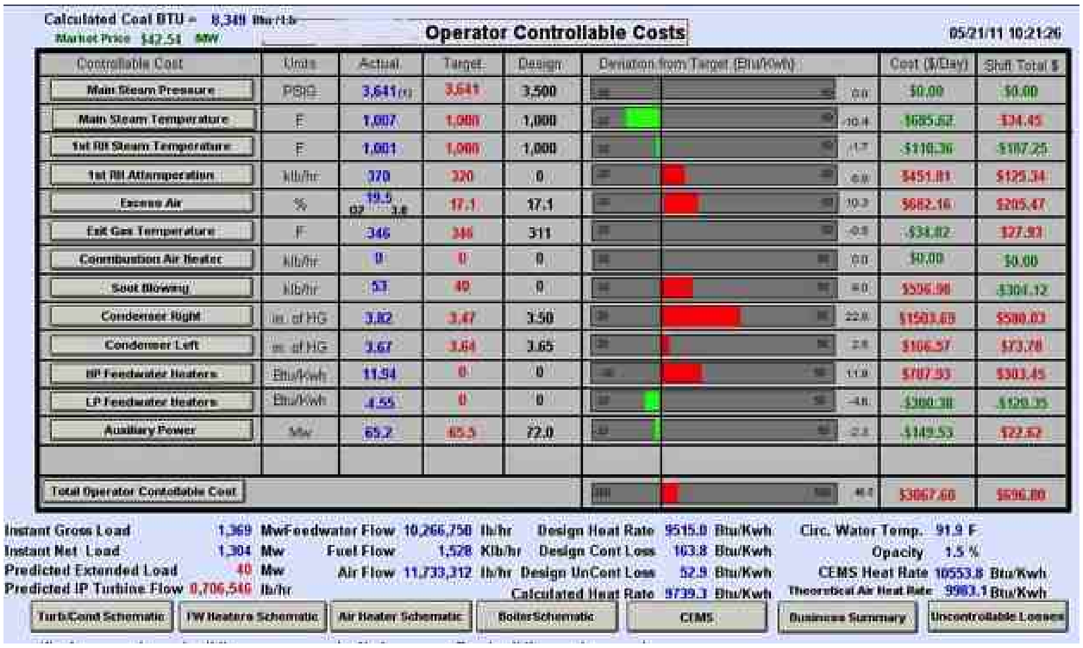
Templates should be set up to continuously monitor key parameters that can cause heat rate losses. The template should include heat rate penalties that result from specific parameters such as:

- Main and reheat steam pressure and temperature
- Condenser backpressure
- High pressure (HP) and Low pressure (LP) heaters

Large U.S. utilities began utilizing continuous monitoring early in the last decade. Although several vendors market products to calculate and track heat rate penalties,

Figure 7-2 illustrates an example of a template internally developed by a utility.

Figure 7-2: Operator Controllable Losses



Calculated Coal BTU = 8,348 Btu/Lb
Market Price $42.51 MW

Operator Controllable Costs

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Controllable Cost	Units	Actual	Target	Design	Deviation from Target (Btu/Kwh)	Cost ($/Day)	Shift Total $
Main Steam Pressure	PSIG	3,641	3,641	3,500	0.0	$0.00	$0.00
Main Steam Temperature	F	1,007	1,000	1,000	-10.4	$685.62	$34.45
1st RH Steam Temperature	F	1,001	1,000	1,000	-1.7	-$110.36	$107.25
1st RH Attemperation	klb/hr	370	320	0	6.8	$451.81	$125.34
Excess Air	%	19.5 O2 3.8	17.1	17.1	10.3	$682.16	$205.47
Exit Gas Temperature	F	346	346	311	-0.5	-$34.82	$27.93
Combustion Air Heater	klb/hr	0	0	0	0.0	$0.00	$0.00
Soot Blowing	klb/hr	53	40	0	6.0	$506.98	-$301.12
Condenser Right	in. of HG	3.82	3.47	3.50	22.8	$1503.69	$500.03
Condenser Left	in. of HG	3.67	3.64	3.65	2.8	$106.57	$73.78
HP Feedwater Heaters	Btu/Kwh	11.94	0	0	11.9	$707.93	$303.45
LP Feedwater Heaters	Btu/Kwh	-4.55	0	0	-4.6	-$300.38	-$120.35
Auxiliary Power	Mw	65.2	65.5	72.0	-2.3	-$149.53	$22.62
Total Operator Contollable Cost					46.5	$3067.60	$696.80

Instant Gross Load	1,369 Mw	Feedwater Flow	10,266,758	lb/hr	Design Heat Rate	9515.0	Btu/Kwh	Circ. Water Temp.	91.9	F
Instant Net Load	1,304 Mw	Fuel Flow	1,528	Klb/hr	Design Cont Loss	163.8	Btu/Kwh	Opacity	1.5	%
Predicted Extended Load	40 Mw	Air Flow	11,733,312	lb/hr	Design UnCont Loss	52.9	Btu/Kwh	CEMS Heat Rate	10553.8	Btu/Kwh
Predicted IP Turbine Flow	0,706,546 lb/hr				Calculated Heat Rate	9739.3	Btu/Kwh	Theoretical Air Heat Rate	9983.1	Btu/Kwh

This template is designed to provide an operator with the tools necessary to enable and motivate him to optimize the unit heat rate. It provides a baseline/design, and a target parameter for comparison to the actual value. Since some equipment is not capable of operating at design conditions, or the operator has been instructed to operate at other conditions, a target field is provided. For example, this unit is operated with a higher sulfur coal than original design so the target exit gas temp has been increased to prevent air heater corrosion. Since the target represents the value that the operator is attempting to control, the graphic is used to illustrate the deviation from this value further emphasizing it. Displaying the cost of the heat rate deviation provides increased understanding of the need to optimize heat rate. Integrating a shift deviation provides a tool to enable competition between shifts providing additional motivation.

Heat Rate Tracking

Displaying the parameters that an operator can control to optimize heat rate has great value, but tracking the total heat rate can be very challenging due to the many parameters that can affect it. Devising multiple means to monitor changes in heat rate provides additional tools to assess heat rate changes. The methods shown in the template include design heat rate, calculated heat rate, Continuous Emissions Monitoring System (CEMS) heat rate, and theoretical air heat rate.

Although each of these is different due to the inaccuracies inherent to the instrumentation, trending them provides a means to track relative heat rate changes. The heat rates displayed in the template are defined as follows:

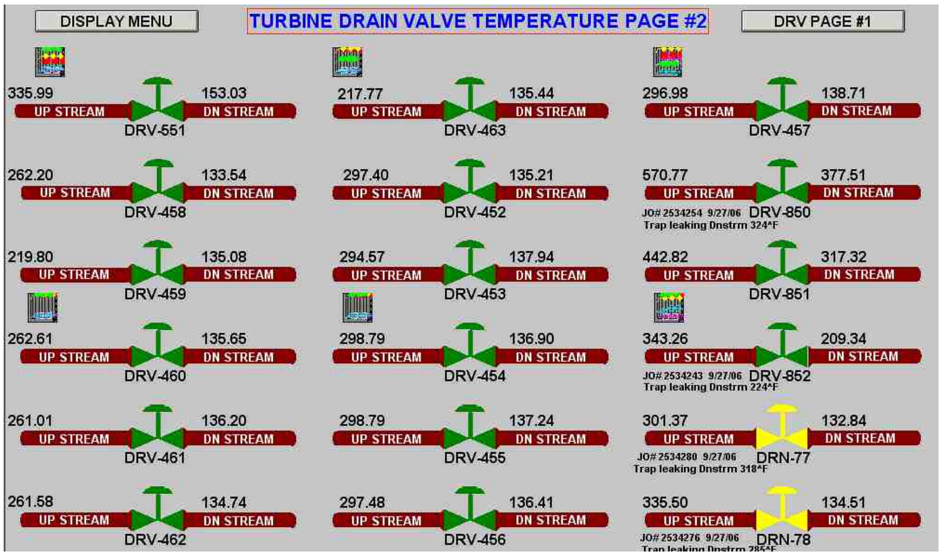
- **Design heat rate** – the baseline net heat rate that represents the heat rate at which the unit could operate if all currently installed equipment were operating at design conditions.
- **Calculated heat rate** – the net heat rate expected based on the heat rate deviation due to controlled and uncontrolled losses.
- **CEMS heat rate** – The net heat rate calculated from the heat input displayed by the Continuous Emissions Monitoring System.
- **Theoretical air heat rate** – The net heat rate calculated from the projected heat input as a function of the theoretical air (total air flow and excess air) and volatile matter.

Since the operator's primary responsibility is operating the unit in a reliable, safe manner, and the number of screens is limited, it is important to provide means to easily navigate between templates. The seven links at the bottom of the page enable quick navigation to other operating screens.

Turbine Drain Valve Leakage

Monitoring and controlling critical temperatures and pressures are an important part of optimizing heat rate; however, losses of steam from the cycle can also significantly impact heat rate. Continuously monitoring turbine drain valve leakage to the condenser by installing remote instrumentation can minimize this impact. This provides a tool to minimize valve and trap leakage as well as track job orders. An internally developed template is shown in Figure 7-3.

Figure 7-3: Turbine Drain Valve Temperatures



Logic associated with this screen has been developed to monitor drains with both traps, and with no traps. Although not displayed in this screen shot, typically drains without traps are monitored by only an upstream thermocouple, since the upstream temperature would typically approach ambient when the valve seat is intact. The logic can also alert an operator to a plugged drain during startup. So monitoring these drains can impact both efficiency and reliability. Although monitoring temperatures provides an effective way to monitor drains for leakage and plugging, it cannot measure the extent of the leakage; the acoustic valve survey described as follows can provide this information.

- An acoustic valve leakage survey is a complementary service that can be utilized on a routine basis before outages. Many plants contract service providers that employ this technology. The technology monitors the frequency and amplitude of the sound emanated from the valve, and utilizes empirical data to determine valve leakage. Several U.S. companies provide this service.
- Several drains on supercritical units, such as the turbine valve above seat drains, operate at supercritical temperatures and pressures. Plant efficiency can be significantly affected by leakage through these valves.

Instrumentation

Precision instrumentation, as referenced earlier, provides the basis for successful control and continuous monitoring. Specifying type E (0.25 percent) thermocouples on critical turbine cycle temperature monitoring, with 0.1 percent accuracy pressure transmitters on critical turbine steam pressures provides accurate and reliable measurement. Although Resistance Temperature Devices (RTDs) can provide even greater accuracy, precision type E thermocouples are recommended due to their improved reliability. For continuous monitoring to be effective, precision instrumentation must be installed in all critical applications. Precision thermocouples provide multiple benefits. They provide both improved heat rate by reducing temperature error and improved monitoring of turbine efficiency. Operating with errant instrumentation can have a significant negative impact on unit efficiency and fuel cost.

Temperature Control

Instrumentation error causing high or low main steam temperature results in significant costs. Operating with a 1 percent low main steam temperature results in a 0.2 percent increase in net unit heat rate. From the authors' experience, on a 1,300 MW unit at typical capacity factors, this could result in costs of over USD 400,000/year. Operating with high main steam temperature shortens superheater tube life due to the effects of creep, which has both reliability and maintenance cost impacts.

Turbine Efficiency Monitoring

Accurately assessing turbine efficiency enables recognition of turbine deposits, blade erosion from exfoliation, and quality turbine outage planning, etc. Installing recommended precision instrumentation can cut the turbine efficiency measurement error to half of that experienced with standard thermocouples.

7.3 BASELINE HEAT RATE REFERENCE

Tracking unit performance is a very challenging process because there are many variable parameters that affect the performance. These variable parameters include condenser circulating water temperature, net load factor, capital modifications, etc. Changes in any of these can have major effects on heat rate. Creating a 'reference document' that can model a 'baseline heat rate' for different conditions of the variables can significantly improve the ability to track heat rate. The expressions 'baseline heat rate' and 'reference document' used here are defined below:

Baseline Heat Rate is defined as the plant net heat rate under the design conditions such as condenser circulating water temperature, net load factor, fuel quality (heating value and chemical composition).

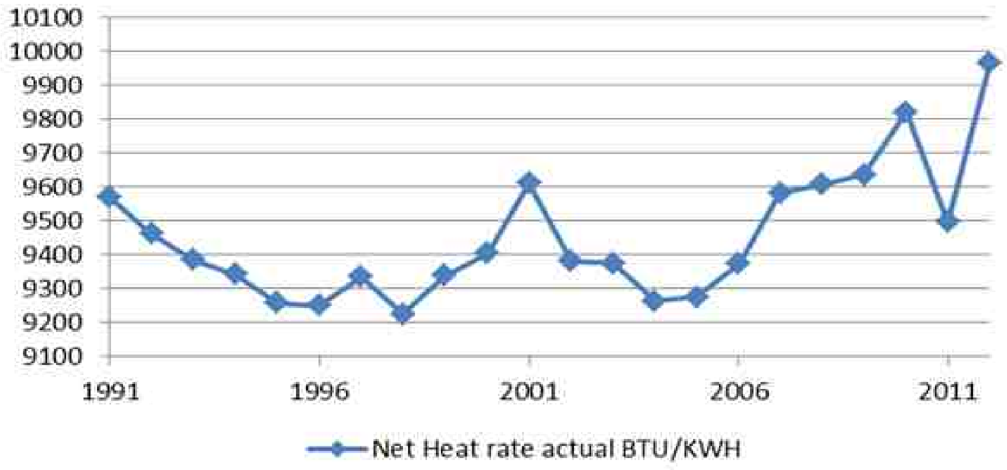
Reference documents contain the above plant design information and a computer-based performance calculation model that can calculate net heat rate and can adjust it for changing variable parameters. The document may be titled "Baseline Reference Document". PEPSE is such a power cycle performance calculation model.

PEPSE can be utilized to develop heat balances for many variable parameters that affect the performance. It can also be used to develop revised baseline and incremental heat rate curves when major capital modifications are installed.

The importance of a Baseline Reference Document is discussed below.

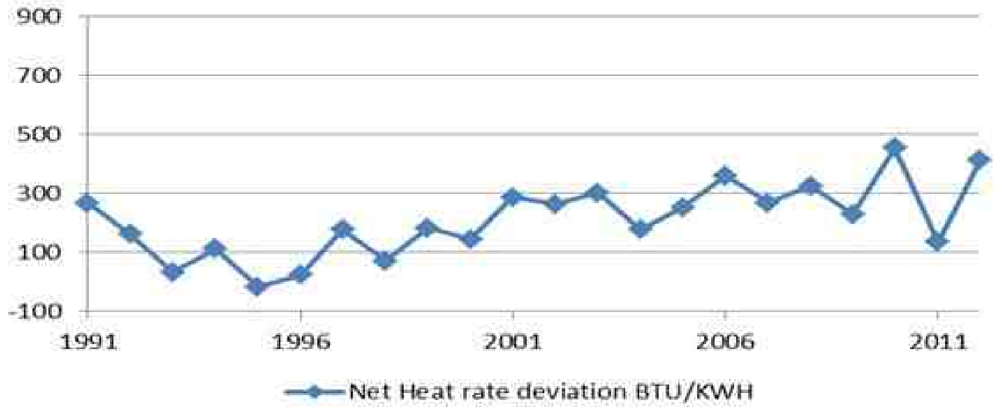
The following chart displays the net unit heat rate for a typical supercritical unit. Over the twenty-year period shown, the heat rate varies by 800 BTU/kWh and the trending suggests a somewhat erratic behavior. Based on this chart, the heat rate appears to degrade by about 400 BTU/kWh in 2001, and then return to its best performance by 2004.

Net Heat Rate Actual BTU/kWh

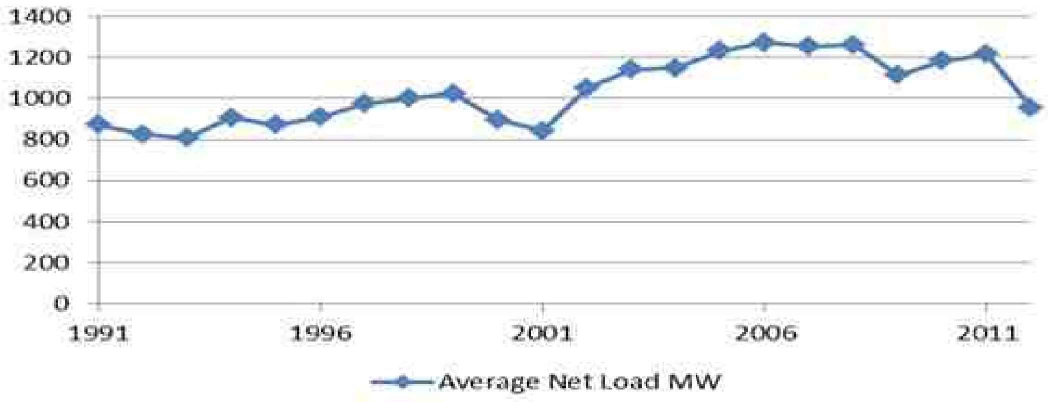


Providing a baseline heat rate enables monitoring of unit performance relative to load and the condenser circulating water temperature. When the unit performance is viewed after adjusting these parameters, the picture becomes very different as shown in the following two charts. The heat rate no longer spikes in 2001 when the changes in the parameters are factored in. The adjustment portrays the 2004 heat rate as comparable to the 1997 heat rate. The adjusted net heat rate deviation also shows that the performance of the unit is gradually degrading when changes in the variable parameters are factored into the calculations.

Net Heat Rate Deviation BTU/kWh



Average Net Load MW

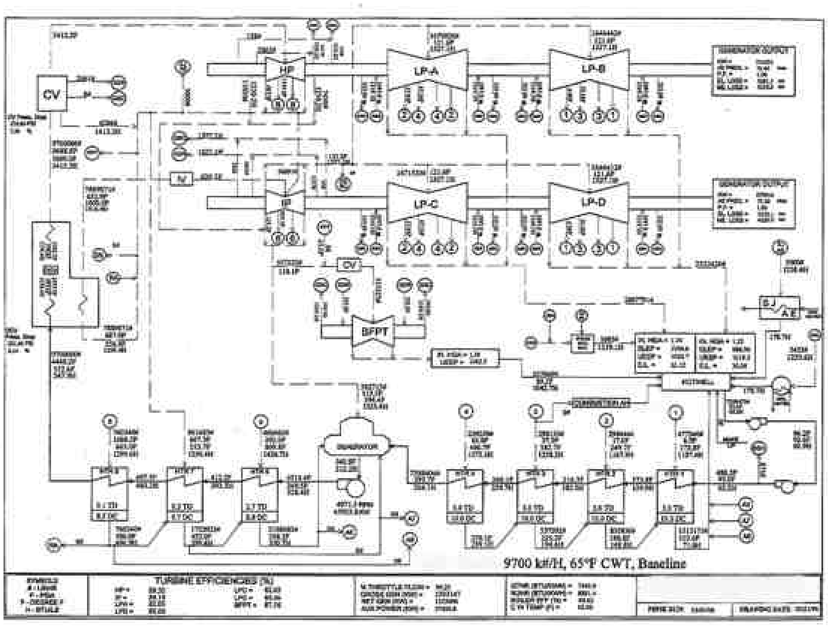


The process of creating a Baseline Reference Document requires:

- Develop baseline heat balance of the power cycle
- Develop models for variable parameters
    - PEPSE modeling of sister units enables comparison of like unit performance
    - Models should be developed for both existing and new units
- Baseline heat balance should be updated when major modifications are installed
- Baseline should not be modified after equipment overhauls because this enables tracking performance degradation and improvements as a result of the overhauls

The heat balance diagram shown in Figure 7-4 provides a baseline for a 18°C (65°F) condenser circulating water temperature. Reference heat balances would also need to be created for other net load factors and circulating water temperatures. Reference is typically limited to the turbine cycle and a fixed steam generator performance is assumed, although steam generator performance can be incorporated into the baseline references.

Figure 7-4: Heat balance - Baseline for an 18°C (65°F) Condenser Circulating Water Temperature



Off-Design Operation Evaluation

Once models have been developed, they can also be used to assess the value of decisions to operate equipment in ways that deviate from design. The heat balance shown in Figure 7-5 can be used to assess the impact on both the heat rate and incremental heat rate. Although the effect of throttling last stage feedwater heaters to increase capacity may not be obvious, its effect on incremental heat rate (the cost of the next MW) can be very significant.

Operating with heaters throttled can increase capacity 2.3 percent on a large supercritical unit, under certain conditions. The chart shown in Figure 7-6 displays both nominal impact on heat rate as well as large impact on the cost of the next MW (incremental heat rate). Although throttling only increases unit heat rate by 0.5 percent, it increases the incremental heat rate by 25 percent. This means that there are probably many units that could be dispatched before the extraordinary measure of throttling heaters is implemented on a supercritical unit to increase load. Oftentimes operators will implement procedures that are not optimal so that rated capacity of the unit can be maintained under extreme conditions. This subject is presented in more detail in Section 7.6.

Figure 7-5: Heat Balance – Heaters Throttled

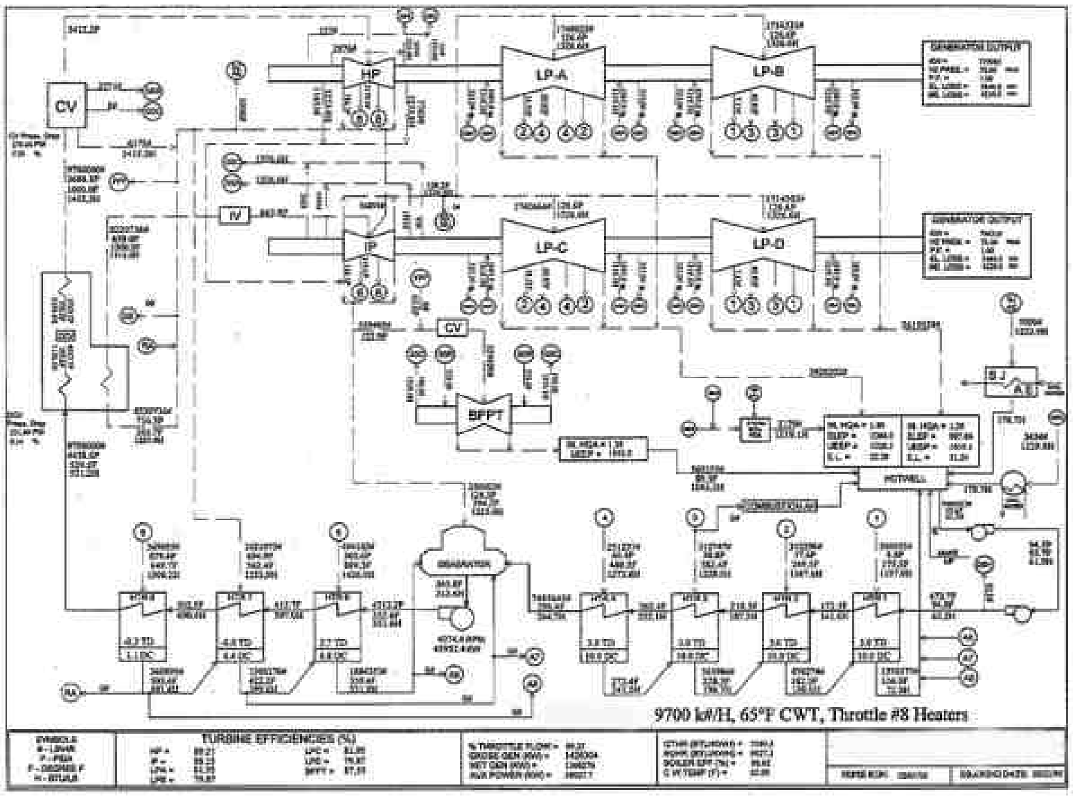
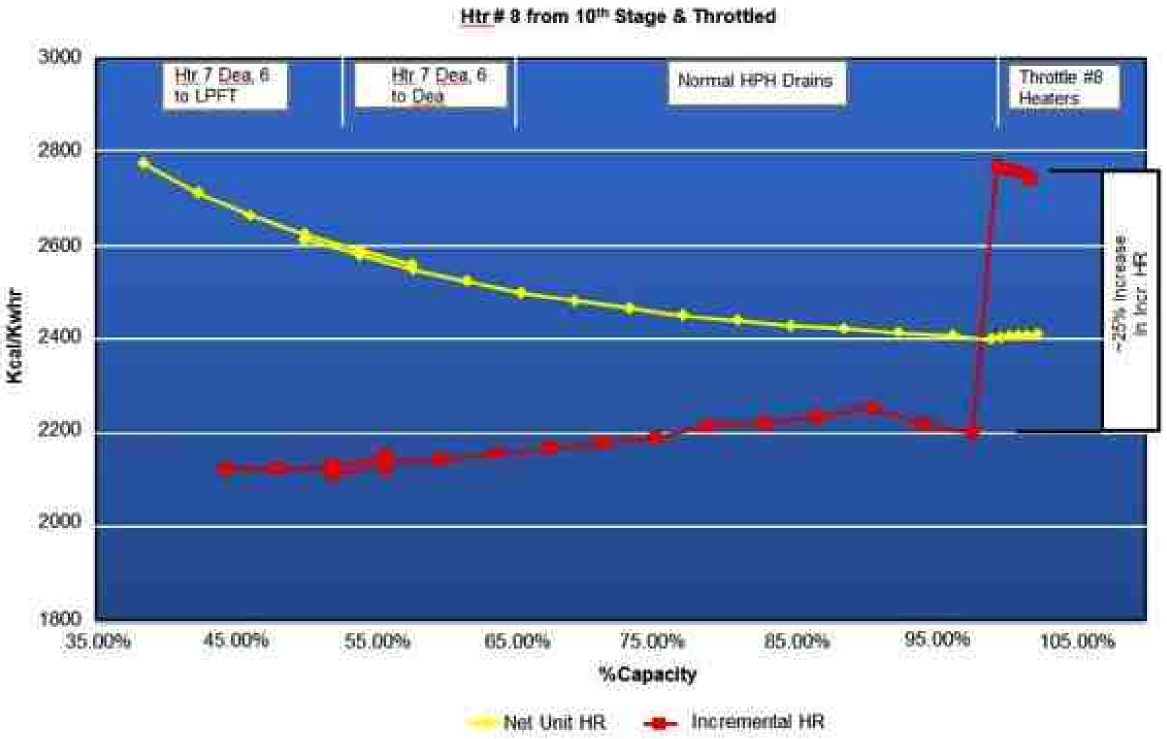


Figure 7-6: Heat Balance - Incremental Heat Rate



Financial Impact

Developing baseline heat balance models and using them to track unit performance can yield significant cost savings. Further utilization of these models to determine the effects of abnormal operation can be used to refine unit operation.

Operating a unit with heaters throttled to attain additional capacity 60 percent of the time over the course of a year has resulted in additional fuel costs exceeding USD 600,000 from operating with abnormal equipment conditions.

7.4 CONDENSER LEAK DETECTION

Condensers have a major impact on all equipment in contact with water/steam within the power generating facility. Its performance impacts both the reliability and efficiency of this equipment. Air leakage can impact the performance of the condenser that can impact both turbine efficiency and capacity. Leakage of contaminated water into the cycle impacts not only the turbine but also the boiler and other water/steam touched equipment. Operating without an effective means of detecting and eliminating this source of contamination will result in other major equipment failures (i.e. steam generator tube leaks, turbine blade failure, etc.). Quality water chemistry is the primary and first building block for reliable power generating facility operation. Experts agree that the condenser is the greatest source of contamination. This section provides direction for dealing with these problems.

Online Instrumentation

Effectively detecting and eliminating these sources of leakage requires a multifaceted approach. This includes good design, monitoring the correct parameters and providing an effective means of identifying the source of leakage. The first step to identify condenser leaks is through the use of online instrumentation.

Cation Conductivity

Cation conductivity provides an optimal measure of water quality to monitor condenser leaks. Cation conductivity is a conductivity measurement in which water is passed through an ion exchange resin column that replaces all positively (+) charged ions, or cations, with hydrogen ions. The water sample is then passed through a conductivity probe. Replacing all cations with hydrogen converts salts, like sodium chloride, to acid, like hydrogen chloride. As acids are more conductive than salts, this creates a more sensitive conductivity measurement. Cation conductivity of the hotwell(s) sample can rapidly identify a condenser tube leak and all units should monitor and record cation conductivity of the individual hotwell samples as well as the combined hotwell sample. For supercritical units, typical hotwell cation conductivity readings are less than 0.25 µmho. Alarms on the combined hotwell sample should be set to energize at a maximum of 0.35 µmho. This alarm should be set as low as possible to alert operators of condenser leakage but high enough to avoid nuisance alarms. Once condenser leakage is detected, maximum clean-up flow should be established to control passage of contamination into the steam generator. It is important to note that just because hotwell conductivity increases above normal range, this alone does not confirm the presence of condenser leaks. Contamination could be from other sources in the cycle, such as air-in-leakage. Other tools are necessary to confirm the presence of condenser leaks.

Hotwell cation conductivity response to load changes is another tool that can be used to confirm the presence of a condenser leak. If a condenser leak is present, the cation conductivity will fluctuate with load. As the unit load decreases, the cation conductivity will increase as the leak rate stays constant and the condensate/feedwater flow decreases. As such, with less condensate/feedwater flow there is less dilution of the water introduced through the leak. Also, some units have condensers with which it is possible to isolate separate sections while the unit is online. In this case, if hotwell cation conductivity decreases while one condenser section is isolated, this is an indication a condenser leak is present in the isolated section.

Sodium Analyzer

A second online instrument that indicates the presence of condenser leaks is a sodium analyzer placed at the hotwell or condensate booster pump discharge. This analyzer measures the concentration of sodium cations in the water. One possible source for sodium ingress to the unit is a condenser leak and any increases in sodium ion concentration will be measured by a sodium .

It should be noted that other sources for sodium contamination to a unit do exist and increasing sodium concentration alone does not confirm the presence of a condenser leak. Sodium hydroxide is particularly harmful to stainless steel materials and turbine blades as it can initiate stress corrosion cracking (SCC). Sodium can also bond with other contaminates (such as chlorides) to form salts. These sodium salts, if transported to the steam cycle can deposit out on boiler/steam generator tubes and turbine blades. When the deposits come in contact with water they can then act as initiating steps for numerous corrosion mechanisms, including pitting and SCC. Figure 7-7 shows a catastrophic failure of an LP turbine that was exposed to sodium salts and experienced SCC.

Figure 7-7: Catastrophic SCC Turbine Failure

Any time a condenser leak on a supercritical unit is suspected an economizer inlet water sample should be taken immediately and forwarded to a laboratory as a priority sample for cation/anion analysis. If a condenser leak is present, elevated levels of sulfates and chlorides will be observed in the laboratory analysis. Once the presence of a condenser leak is suspected or confirmed, it is imperative that Water Chemistry Balance Best Practice (Section 5.2) action levels/limits be followed for cycle conductivities, chlorides, sulfates and sodium. While operating with a condenser leak, to continue to monitor contaminant levels, it may be necessary to forward additional water samples to a laboratory.

Actions that can be taken to minimize the impact of the condenser leak are as follows:

1. Maximize condensate clean up system flow to reduce the level of impurities in the cycle and verify the conductivity indication is correct.

2. Begin a systematic investigation into the cause of the upset condition and correction of the problem. Possible sources of the upset include make-up water quality, condensate polisher performance and condenser leakage.

3. Utilize on-line leak detection of the condenser and repair the leak in service if possible.

Prior to reducing unit load or removing the unit from service the conductivity reading should be verified as correct with laboratory equipment. A portable conductivity instrument and flow through cell is recommended for this check.

For supercritical units, it is imperative to maintain concentration of sodium, chlorides and sulfates at or below 3.0ppb in main steam and at the economizer inlet. As such, anytime a suspected or confirmed condenser leak is present and economizer inlet cation conductivity increases above a normal range, economizer inlet samples should be sent to a laboratory for priority cation/anion analysis to determine contaminant levels. If contaminant levels are below the limits and the unit continues to operate with a condenser leak, an economizer inlet sample should be sent to a laboratory for priority analysis at a minimum of once every two weeks to monitor contaminant levels.

Units with condensate cleanup systems have the capability to remove contaminants introduced from condenser leaks. However, it is important to recognize that condensate cleanup systems are not designed to handle long term condenser leaks. Ongoing condenser leaks can damage condensate cleanup ion exchange resins and eventually overwhelm the system's ability to remove contaminants. Large or numerous condenser leaks can quickly overwhelm a condensate cleanup system's ability to remove contaminants. Once past the condensate cleanup system, contaminants are introduced directly into the condensate/feedwater. As such, even with the protection of a condensate cleanup system, it is still imperative for condenser leaks to be promptly addressed.

It is also important to recognize the risk posed by long term, smaller condenser leaks. Even if a leak is not serious enough to place chemical parameters within action levels, a long term leak can be as damaging as major leaks for units both with and without condensate cleanup systems. For units with condensate cleanup systems, the longer a leak is allowed to continue, the greater the risk for damaging the ion exchange resin. Furthermore, long term condenser leaks have been known to foul condensate cleanup resin such that the resin could no longer maintain water quality requirements.

Air Leakage Monitoring and Control

Air leakage can be monitored through either local or remote monitoring equipment. Vendors market instrumentation capable of monitoring air flow from each condenser as well as instrumentation capable of monitoring the air removed by each air vacuum pump or Steam Jet Air Ejector (SJAE). By monitoring air flow from each condenser, the condenser with the excess air leakage can be identified. Measuring the air flow removed by each of the vacuum pumps/SJAEs will identify poor performing air removal equipment. Trending of the air removed will enable detection of excess air leakage.

Maintenance of the air removal equipment is also important. The high heat load experienced by SJAE makes them especially susceptible to scale buildup within the tube. To ensure high performance, the tubes should be regularly inspected and cleaned.

Leak Check Methods

When a unit has or is suspected to have condenser water or air leaks, there are numerous methods that can be used to locate the leaking condenser tube(s).

Depending on the configuration of the condenser, units with multiple waterboxes have been successful at using a sample pump to extract water from pertinent locations on the condenser floor to identify the pass in which the leaking tubes exist. The potential for success is a function of the condenser configuration and flow patterns that exist within the condenser.

Methods that can be utilized for identifying air and water leaks both online and offline are summarized below.

Online Methods

Note: Identifying and repairing leaking tubes require the ability to remove a section of the condenser from service and isolate and drain the water side.

- Ultrasonic probe: Detecting tube water leaks requires placing an ultrasonic probe at the face of the tube sheet to detect the sound created by the leaking tube as the condenser vacuum draws air through the leak. Very small leaks can be detected by the method. The fluid flow pattern changes from laminar to turbulent at the leaking location causing a 25-40 kHz ultrasonic frequency to be produced. This sound is detected by the acoustic sensor. These sounds can then be observed either through a converted sonic noise or on a digital/analog display meter. This technique is a very effective method of detecting leaking tubes. (Case studies are presented in Section 7.9.)

  Detecting condenser air leaks requires utilizing the probe in a similar manner in external areas around the condenser. In areas where air leaks are present ultrasonic sound is produced and can be detected.

- Helium/Sulfur Hexafluoride (SF_6): Detecting tube water leaks involves injecting either of the inert gases helium or SF_6 into a portion of a condenser tubesheet. The condenser vacuum pump exhaust is then tested for the injected gas. If no gas is detected, no tube leak is present in the portion of the tubesheet where gas is injected. If gas is detected, a condenser leak is present in that portion of the tubesheet and a smaller portion of the tubesheet is again injected with gas. This process continues until the leaking tube(s) are located. This technique is an effective accurate test, but time consuming.

  Detecting condenser air leaks involves injecting either of the inert gases helium or SF_6 external to the condenser in the area of the suspected leak. If no gas is detected, no tube leak is present in the area where gas is injected. If gas is detected, a condenser leak is present in that area and other means such as inspection or shaving cream can be used to identify the leak. (Note: Environmental regulations restrict use of the chemical SF_6).

- Candle: This method involves passing a lit candle over the tube sheet. The candle flame will be pulled toward the leaking tube. This is a low sensitivity technique.

- Foam/Shaving Cream: Detecting tube water leaks involves coating one end of condenser tubes and blocking the other end or coating both ends of condenser tubes with a foam agent, such as shaving cream. A leaking tube will pull the foam into the tube.

  Detecting air leaks involves applying the shaving cream to joints, flanges, welds which are suspected to be leaking and observe areas where shaving cream is sucked into the condenser.

  Plastic Wrap: This method involves applying a plastic cling wrap, such as Saran Wrap, over both ends of condenser tubes. A leaking tube will pull the plastic wrap into the tube. For this method to be successful a good seal between the plastic wrap and tube ends is required.

Offline Methods

- Flooding: This method can only be performed while the unit is offline. The hotwell is filled with condensate that fills and runs out of any leaking condenser tube. It is possible to mix a fluorescent dye into the water to improve the visibility of any water running from a tube.

  It is very important that the water temperature used to fill the condenser is a minimum of 17°C (60°F) so as to stay above the nil ductility value of the carbon steel condenser shell plate welds. Carbon steel welds can become brittle and fail when exposed to stress at temperatures below 17°C (60°F), such as when hydrostatically testing a condenser. If the water used during a flood test is at a lower temperature than ambient air temperature, tubesheet “sweating" can occur which makes it very difficult to distinguish actual tube or joint leaks from surface moisture.

If time permits, drying of the tube sheet (using an air mover) can facilitate finding any leaks.

On side or back exhaust condensers, flooding the condenser shell requires installation of hydro blanking plates at all exhaust openings. This is very time consuming, expensive, and normally only done on initial construction or a complete re-tubing. Out-of-service leak checks, therefore, are the same as those used for in-service testing except, instead of only vacuum checks, air pressure testing 0.15-0.20 kg/cm^2 (2-3 psig) can also be done on the steam side.

It is recommended that flooding the condenser be used as a preventive maintenance technique whenever possible, especially during major outages. This will identify small leaks that have minor effects on chemistry and any leaks that developed during a unit outage.

7.5 CONDENSER PERFORMANCE OPTIMIZATION

A poor performing condenser can significantly affect both the efficiency of the turbine and reduce the power generated. The factors required to optimize condenser performance include: monitoring to determine condenser performance, quality water treatment required to maintain the performance, and cleaning to restore design conditions.

Performance Optimization Strategies

Initial temperature difference (ITD) is a very effective means of monitoring condenser performance. This is defined as hotwell temperature minus condenser circulating water inlet temperature. This data can be used to determine when to troubleshoot condensers.

Comparing the performance of one condenser to that of a like unit can provide quick insight into the condition of the condenser.

Reducing the number of pumps in service during mild operating conditions can improve performance. Removing a pump from service reduces both auxiliaries and circulating water flow. Reducing the flow causes changes in tower operation that reduces cold circulating water temperatures. Implementing this strategy requires testing to determine the ambient temperatures that require restarting the additional circulating water pump to optimize efficiency.

Hennon of Clean Air Engineering provides the following insights into condenser optimization: The performance of a condenser is indicated by two performance parameters, the heat transfer coefficient for the condenser and the pressure loss through the tube side of the condenser. A decrease in the heat transfer coefficient could be attributed to micro-fouling of the heat transfer surface, an increase in air leakage rate, or decrease in the available area for heat transfer by physical blockage of the condenser tubes by debris. For a constant circulating water flow rate, an increase in the pressure loss across the condenser is an indication of tube blockage. These performance parameters may be calculated by measuring the following parameters [5].

- Condenser pressure
- Condenser inlet circulating water temperature
- Condenser outlet circuiting water outlet temperature
- Circulating water flow
- Water box differential pressure

The non-condensable flow rate from the air ejectors should be measured to provide diagnostic information about any observed decrease in the heat transfer coefficient for the condenser. If an observed decline in the heat transfer coefficient can be attributed to an increased air leakage, the problem can frequently be isolated by examination of plant logs. In many cases, the leak can be repaired while the unit is online. When the decrease in performance is due to fouling on the tube side of the condenser, it will usually be necessary to clean the condenser tubes during an outage. When the circulating water has a high potential for fouling, a continuous monitoring system may be justified. Hennon recommends the following instrumentation accuracy for performance

Table 7-1: Measurement Accuracy of Condenser Measurements

Parameter	Units	Required Accuracy
Condenser pressure	kPa	0.14
Circulating water inlet temperature	°C	0.17
Circulating water outlet temperature	°C	0.17
Circulating water flow	%	5
Circulating water differential pressure	kPa	0.69

The circulating water outlet near the nozzle is too stratified to allow an accurate measurement of the outlet water temperature at this location. It is usually necessary to measure the condenser outlet temperature some distance downstream, most often the cooling tower circulating water inlet, to obtain an accurate temperature measurement. Most plants have no flow element to measure circulating water flow. The performance degradation of condensers tends to be a long term process with the degradation progressing for months before reaching actionable levels [6].

Condenser Cleanliness

Hennon and Wheeler provide guidance on the process required to evaluate condenser cleanliness. Condenser cleanliness provides an indication of the overall performance of the condenser. Condenser cleanliness is defined as the ratio between the actual heat transfer coefficient of the condenser and the predicted heat transfer coefficient for a condenser with clean heat transfer surfaces. The actual heat transfer coefficient calculation is shown below [5].

$$U \quad \frac{Q}{A \;\; T_{lm}}$$

Where

U = calculated heat transfer coefficient, Btu/hr/ft2/°F

Q = heat transfer rate, Btu/hr

A = heat exchange area of the condenser tubes, ft2

ΔT_{lm} = log mean temperature difference for the condenser, °F

The heat exchange area of the condenser tube is found on the heat exchanger specification sheet and can be calculated directly from the number and physical dimensions of the condenser tubes. The heat transfer rate is calculated by.

$$Q \quad \dot{m}_{cw} c_p (T_{hw} \quad T_{cw}) \quad q_{cw} \quad c_p (T_{hw} \quad T_{cw})$$

$\dot{m}_{cw}$ = mass flow rate of circulating water, lbm/hr

q_{cw} = volumetric flow rate of circulating water, ft3/hr

c_p = heat capacity for water, Btu/lbm/°F

ρ = density of water

T_{hw} = hot water temperature at cooling tower inlet, °F

= condenser outlet temperature

T_{cw} = cold water temperature at cooling tower outlet, °F

= inlet temperature for condenser

The log mean temperature difference for the condenser is calculated

by $$T_{lm} \quad \frac{T_{hw} \quad T_{cw}}{\ln \dfrac{T_s \quad T_{cw}}{T_s \quad T_{hw}}}$$

Where

T_s = saturation temperature at the measured condenser pressure,°F

The heat transfer coefficient for clean tubes is calculated from methods contained in the Heat Exchanger Institute (HEI) Standards for Steam Surface Condensers. The condenser cleanliness is calculated by

$$C_f \quad \frac{U}{U_{clean}}$$

C_f = condenser cleanliness factor

U_{clean} = heat transfer coefficient for clean condenser tubes

The condenser cleanliness factor is used to adjust the condenser heat transfer coefficient so that a condenser performance curve relating the condenser pressure to the inlet water temperature, flow rate, and heat duty can be generated (Hennon and Wheeler).

Deposition

Maintaining high condenser performance requires a high cleanliness factor. The key to accomplishing this and thereby minimizing deposition is to maintain a quality water treatment program.

Deposition presents the most serious barrier to the transfer of heat through a surface and can be divided into two forms -- fouling and scaling. Fouling, due to suspended solids in the water, is the accumulation of water suspended materials on tower fill or heat exchanger surfaces. Scale is a dense coating of inorganic materials and results from the precipitation of soluble minerals from supersaturated water. The formation of scale most often occurs when the water becomes oversaturated or when water temperature increases. For some scale species, such as calcium compounds, solubility decreases with increasing temperature. As such, these deposits usually occur first at the outlet end of the condenser where the temperature is the highest. The rate of formation of the scale will depend on temperature, alkalinity or acidity, and the amount of scale forming material in the water.

The most common type of scale found in cooling water systems is calcium carbonate. This normally results from the breakdown of calcium bicarbonate and the degree of scaling depends on the levels of calcium hardness and alkalinity in the cooling water. It is important to note that as temperature increases, the solubility of calcium carbonate decreases. Another common type of scale is calcium sulfate, which results from increased levels of sulfates in the cooling water. The solubility of calcium sulfate also decreases with increasing temperatures. In particular, attention should be given to calcium sulfate scale for cooling towers utilizing sulfuric acid to control circulating water pH due to the increased risk for elevated sulfates in the water. Other types of scale found in cooling water systems include silica and magnesium compounds.

Scaling Indices

“A formation prediction can be calculated with the use of indices such as the Langelier Saturation Index (LSI). It is recommended that an LSI calculation be performed once a day, preferably in the afternoon when temperatures are warmest and conditions are most favorable for deposition. If the LSI calculation produces a positive value, the potential to form scale exists; and if a negative value is produced, no scale potential exists. At no time should an LSI value be greater than 2.2. If the values reach 2.2, changes in the treatment program need to be made immediately to decrease the potential for deposition.”

The Langelier index is a tool that can be used to prevent calcium carbonate deposition. It should always be maintained below 2.2 to prevent the formation of calcium carbonate. A detailed description of the Langelier index is provided in Section 7.7 (Cooling Tower Performance Monitoring).

Deposition Control

Cooling systems may require the application of an appropriate scale inhibitor to keep the heat transfer surfaces clean. A scale inhibitor is a solubilizing specialty chemical that by interfering with crystal growth has the ability to keep scale forming material in solution at concentration levels substantially higher than normal. These inhibitors function with the use of an adsorption mechanism. As highly oriented ion clusters in a solution begin to form and continue to grow, they eventually will precipitate or dissolve. Inhibitors prevent precipitation by adsorbing onto the newly emerging crystal and blocking active growth sites. This stops further crystal growth and encourages the crystal to dissolve. Once the crystal dissolves, the inhibitor is released back into the solution and is free to repeat the process.

The most commonly used scale inhibitors today are polymeric organics and organic phosphonate chemicals. Hydroxy Ethylidene Diphosphonic Acid (HEDP) is the recommended phosphonate and is frequently used to control types of calcium and manganese scale. HEDP concentrations are to be kept in the range of 0.75 – 1.25 ppm at all times to ensure adequate scale protection. It should be noted that HEDP is a weak chelating agent and will attack steel or copper alloys. If the HEDP concentration is not kept within limits, it can precipitate out of solution and higher steel corrosion rates or calcium carbonate deposition problems may be experienced. Also, HEDP is sensitive to soluble iron and iron oxide deposits. In the presence of iron and phosphonates, it degrades and becomes ineffective. As such, continuous and uniform feed of HEDP is necessary. If the feed is interrupted or lost, heavy scale can form in a matter of minutes.

Polymer chemicals can be used to control contaminants, such as mud and silt, which do not form hard scale deposits. Because these contaminants are suspended solids, their deposition is often more flow related than heat related. Without polymer chemical control, these suspended solids can drop out in low flow areas, such as the tower sump and fill, leading to fouling. The amount of polymer required to control deposition of these solids is a direct function of the makeup water quality and tower concentration cycles.

To help provide protection against deposition and scale it is also recommended to control tower conditions. Specifically, as mentioned previously, the pH should be controlled such that it does not increase above 8.5. As the pH increases, conditions become more favorable for contaminants to deposit out of the bulk water. Controlling the pH will keep the tower conditions suitable for controlling the deposition of contaminants."

Cleaning and inspection of condenser tubes

There are many technologies available to clean condenser tubes. Three are described below.

Scrapers provide the most effective means of cleaning condensers. Potential problems that have been experienced include scrapers left in tube and incorrect size scrapers being utilized.

High pressure nozzle cleaning is another method that can be used to clean the tubes. Some of the problems that can develop when implementing this procedure include, deviation from the prescribed cleaning rate (m/sec), using incorrect water pressure, tube sheet damage due to push through of wand. The contractor's performance should be monitored to ensure that there is adherence to the specified procedure.

Rotary brush cleaning machines are also available. These machines can remove excess loose dirt but cannot remove tenaciously attached scale.

Regular inspections of the condenser should be performed to assess the tube cleanliness and to observe fretting corrosion, etc. The inlet tube sheet should be inspected for plugging during opportunity outages. Tubes at the outlet end of waterbox should be inspected for internal surface deposits. Condensers also need to be inspected for fouling and deposition on a regular basis. Condenser inspections should occur during all scheduled unit outages of appropriate length. If there is evidence of fouling or deposition in the condenser immediate changes will need to be made to the circulating water treatment program.

7.6 FEEDWATER HEATER DESIGN AND MAINTENANCE

Reliably and effectively maintaining the feedwater heaters of a supercritical unit is important. Optimum operation requires attention to details encompassing a multi-faceted approach. Design, good operating and maintenance practices, and continuous performance monitoring help providing a long-term sustainability and cost benefit for the unit. Some of the best practices include the following:

1. Design

It is important to design the system with a means to operate with a heater string out of service. There are two recommended ways to accomplish this task. Design with two 50 percent strings and a bypass or provide three 50 percent capacity heaters. Both enable the removal of a heater string for maintenance without impacting the capacity of the overall unit. Utilizing three heater strings provides a spare string while reducing the normal duty on the heaters under normal operating conditions, thus enhancing the overall unit life.

2. Operating Practices

Minimizing cycling of heaters

It is well known that frequently cycling units from service shortens their life and reduces reliability. Heaters can also be impacted by cycling. Implementing practices to minimize cycling can extend their life.

Minimize cycling of heaters - Remove heaters from service only when necessary (i.e. tube leak, etc.) by compiling small jobs together (i.e. small external leaks, instrumentation problems, etc.). This will minimizes unnecessary cycling of heaters and prolong their useful life.

Utilizing instrumentation to enable timely leak detection

Timely leak detection provides significant payback. Just as boiler leaks often result in collateral damage, heater leaks left unrepaired can damage adjacent tubes. These heater leaks also impact the heater performance and unit heat rate. Available instrumentation already installed for other purposes can often be used for leak detection.

Acoustic leak detection

Acoustic leak detection can provide a means of detecting heater leaks. This has been successfully implemented by several plants.

Flow monitoring

Installing and monitoring flow instrumentation can be an inexpensive method of early leak detection by alarming the difference between flows before and after heaters. Many plants monitor boiler feed pump suction flow (before heaters) vs. feedwater flow (after heaters). Since these instruments are already installed for other purposes, there is very little cost required to implement this monitoring.

Implement safe heater repair practices

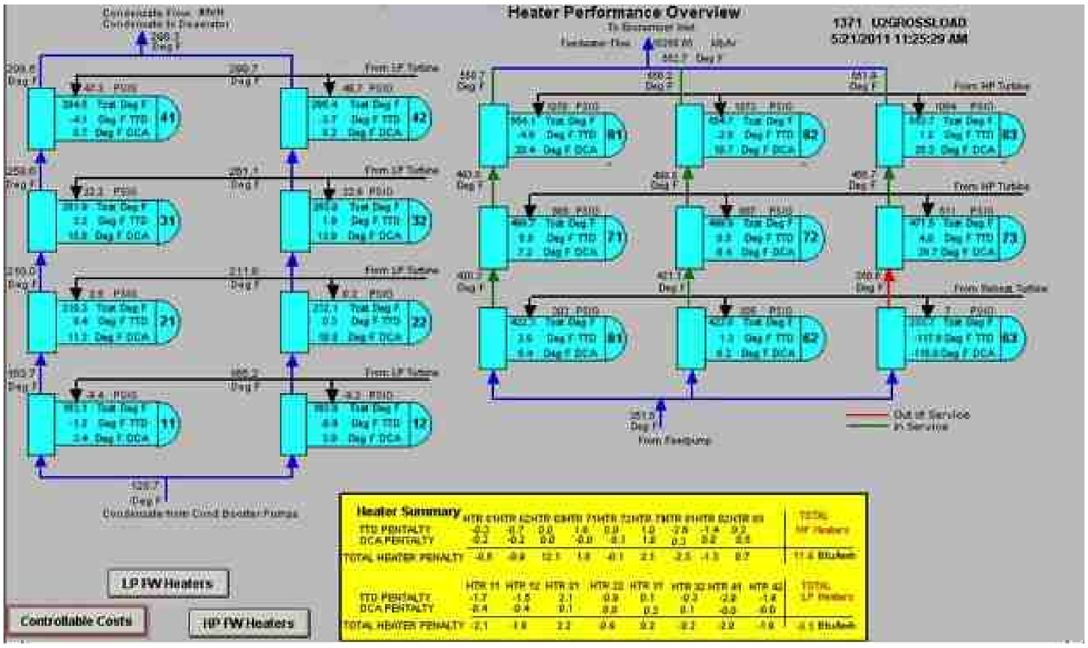
Online heater tube repair should not be attempted unless heater can be isolated with double valving.

Monitor heater performance

Installing monitoring equipment with the capability to utilize the existing instruments to monitor feedwater terminal temperature difference (TTD) and drain cooler approach (DCA) temperature enables tracking of heater performance. This facilitates detection of such problems as partition plate bypass.

Figure 7-8 provides an overview of the parameters that should be monitored on HP heaters to effectively track their performance. The display provides an overall assessment of the heaters at a glance. It displays heater TTDs, DCAs, saturation temp, press, and inlet and outlet temps. This information is aggregated to provide the heat rate penalties that are caused by any performance degradation. To provide continuity for the operator, links are also provided to enable easy navigation to other screens.

Figure 7-8: Heater Performance Overview



In addition to the parameters displayed on this template, carbon steel HP heaters can develop scale on the internal tube surfaces that can result in feedwater pressure drop, causing additional pump head thereby impacting heat rate and capacity. Correcting this condition typically requires chemical cleaning of the feedwater heaters.

3. Predictive Maintenance Practices

Eddy current testing

Reliable heater operation requires effective predictive maintenance practices. Eddy current testing is a tool that can be used to detect marginal tubes to avoid unexpected tube failure. Marginal tubes are plugged to avoid heater leaks.

Heater tube failure can be propagated by several causes. Some of these include:

- Tube plugging (leaks)
- Drain Cooler Zone Level Control
- Steam Impingement Desuperheat Zone
- Tube Vibration
- Steam Impingement Condensing Zone
- Inlet End Erosion
- Loss of impingement Plates

- Although these failure modes can result in immediate failure, they often cause erosion or thinning of the tubes. Typical wear areas are drain cooler plates, baffles, and the perimeter.
- Providing the NDE contractor with accurate information on the tube material, size and thickness to enable them to properly calibrate the equipment can significantly enhance the eddy current data accuracy.

Testing frequency varies with the condition of the heater

- New heaters – Typically companies offering this service recommend testing every 5-10 years
    - Specifying factory testing on a percentage of tubes can improve reliability
- Heaters with tube leak history or at End of Life – testing every outage can extend heater life and avoid unexpected heater outages.

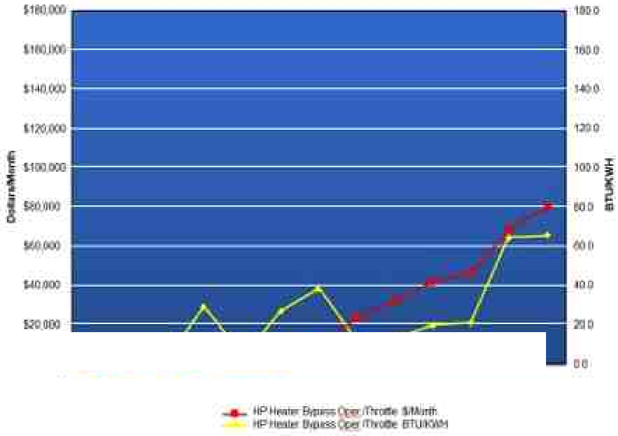
Case Study

The HP heaters on a 1,300 MW unit were approaching end of life. Although the unit had three 50 percent heater strings, removing a string from service increased the duty on the remaining in service strings, increasing the probability of a leak on that string which would cause a curtailment. To reduce the probability of a leak, eddy current testing was utilized to detect weak tubes. The testing found tubes in the drain cooler area and the periphery of the heater to be thin. Those tubes were plugged. This enabled operation of the heaters with few leaks.

4. Heater Throttling/Bypass Criteria and Penalties

Figure 7-9 displays the heat rate penalty for 13 units on a large fossil U.S. utility that operates many supercritical units. Large heat rate penalties can develop from operating with heaters out of service or throttled due to operating issues. As can be seen from the chart, the penalties can become quite large over the course of a year.

Figure 7-9: Heater Throttling/Bypass Penalty



Objective

Estimate the cost impact of throttling/bypassing the HP heaters required to allow the unit to achieve additional generating capacity, and change the pricing of its generation to more profitably dispatch the unit.

Definition of terms

Average heat rate = heat input/net MW

Incremental heat rate = $\lim_{\Delta MW \to 0} \left(\frac{\Delta heat\ input}{\Delta MW} \right)$ OR $\frac{d(heat\ input)}{d(MW)}$

Equipment impacted by throttling/bypassing heaters:

Throttling steam to the last HP heater or bypassing HP heaters can impact the unit in many ways. The potential impacts are identified as follows:

Environmental & Fuel Cost

- Increases average heat rate up to 0.8% or 18 kcal/kWh (71.4 Btu/kWh)
- Increases incremental heat rate up to 25% or 600 kcal/kWh (2,381 Btu/kWh)

Generator Capacity

- In cross compound units throttling heaters can result in exceeding RH generator capacity due to the increased reheat flow.

Steam Generator

Heat Input – Due to equipment limitations, heaters are often throttled to increase unit capacity. This can result in an increased capacity of 2.5% with an average heat rate increase of an additional 0.8 percent. This results in an approximate 3 percent increase in heat input.

Erosion – Erosion is caused by the increased gas flow velocity. Since erosion increases as the cube of velocity, the 3 percent increased flow velocity results in a 10 percent increase in erosion. This can have a very detrimental effect on tube maintenance and reliability in units that burn high ash coal. Increased SH pad welding would be required during outages. The increased economizer erosion will result in increased leaks that are difficult to repair due to tight tube spacing.

IP turbine

The resulting Reheat flow increase can cause the IP turbine to exceed OEM guidelines resulting in SPE and or blade failure.

LP turbine

The resulting LP turbine flow increase can cause the LP machine to exceed OEM guidelines resulting blade fatigue failure.

Throttling/bypass criteria

Throttling or bypassing heaters provides a method for optimizing the dispatch of units. To minimize the heat loss penalties associated with modifying the equipment configuration on a supercritical unit is achieved by throttling the highest pressure heaters. On the plant evaluated in this section, the recommendation is to increase the incremental cost by 40 percent when heaters are throttled. In the authors experience with the following case study, throttling operation resulted in additional annual fuel costs ranging from USD 300,000- 650,000 on large supercritical units.

Case Study: Evaluate throttling/bypass cost

Estimate the cost impact of throttling the extraction steam to highest pressure FW heater or bypassing the FW flow on the HP heaters to attain additional generation, to enable adjustment of the dispatch price to more profitably dispatch the unit.

Method

- Run heat balance models for the load range, accounting for changes in heater drain configuration, and throttling of the highest pressure HP heaters at the high end of the load range.

- Estimate incremental heat rates based on changes in heat input and net MW from the heat balance results.

Figure 7-10: PEPSE Heat Balance Results for Summer Circulating Water Temperatures

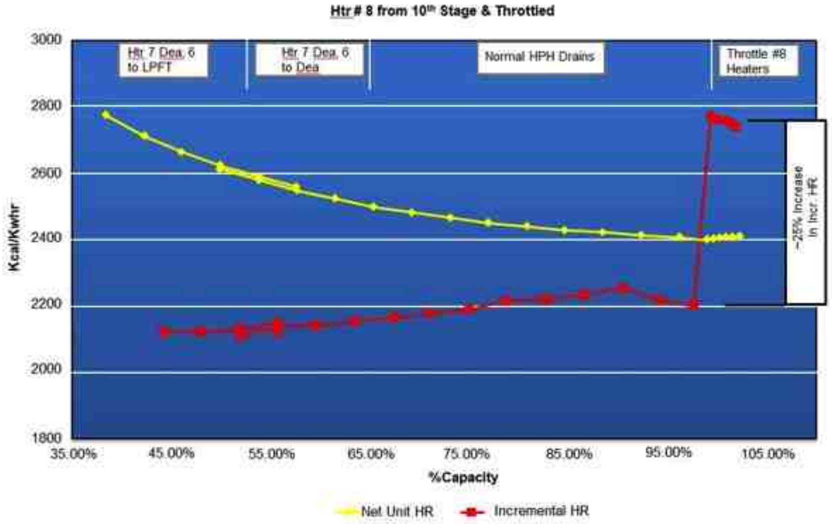


Figure 7-10 displays the results from the PEPSE heat balance runs for a 90°F circulating water temperature. The "dogleg" at the end of the curve accounts for the estimated 25 percent increase in incremental heat rate associated with throttling the last HP Heaters. The load at which this dogleg occurs will vary seasonally – i.e., the maximum load achievable without throttling will decrease as circulating water temperature increases.

1. **Establish Dispatch methodology:**

   - Based on costs incurred from equipment impacted by throttling/bypassing heaters, the incremental dispatch cost should be increased.

     o Typically operators throttle heaters to a specified pressure when additional capacity is required. The throttling often exceeds the amount necessary to attain the requested generation. Historical data indicates that the additional incremental cost incurred by throttling heaters typically approaches 40 percent. Throttling heaters also causes additional equipment maintenance due to temperature transients, and elevated gas velocities; however, the present value of these capital and maintenance costs are difficult to identify and are assumed to be covered by the 40 percent cost adder. Throttling operation can result in additional annual fuel costs ranging from USD 300,000-650,000 for a large supercritical unit.

   - Since the generating capacity changes with ambient conditions, the maximum capacity beyond which throttling is required can change daily and should be updated by the plant as required.

Table 7-2: Throttling Penalties Experienced on Supercritical Units

Plant A						Plant B				
Heat Rate penalty (BTU/KWH)	Additional generation (%)	Incremental Heat Rate penalty (BTU/KWH)	Heaters throttled or O/S (hours)	Monthly fuel cost (dollars)		Heat Rate penalty (BTU/KWH)	Additional generation (%)	Incremental Heat Rate penalty (BTU/KWH)	Heaters throttled or O/S (hours)	Monthly fuel cost (dollars)
43	1.34%	3179	670	$93,000	JAN	8	0.17%	4594	124	$13,000
42	1.21%	3433	596	$83,000	FEB	0			0	$0
13	0.44%	2906	233	$21,000	MAR	22	0.99%	2235	517	$46,000
13	0.45%	2882	50	$10,000	APR	39	1.63%	2400	709	$79,000
30	0.88%	3366	503	$62,000	MAY	22	0.99%	2267	550	$46,000
18	0.47%	3753	348	$33,000	JUN	29	1.13%	2530	715	$55,000
25	0.61%	4172	454	$50,000	JUL	22	0.88%	2458	411	$31,040
23	0.42%	5385	389	$45,000	AUG	31	1.41%	2223	639	$65,036
24	0.54%	4312	399	$44,000	SEP	36	1.27%	2844	721	$71,572
24	0.56%	4340	441	$50,000	OCT	5	0.16%	2943	104	$10,267
29	0.79%	3715	522	$60,000	NOV	0		0	0	$0
37	0.90%	4117	708	$83,000	DEC	0		0	0	$0
27	0.69%	3853.5	5313.0	$634,000	Annual Impact	18	0.71%	2510.0	4490.0	$416,915

Although both plants in Table 7-2 are the same design and have utilized throttling to attain additional generation, the plant A has been operated in a much more conservative manner, by over-throttling the heaters, incurring 50 percent more heat rate impact to attain each additional MW.

Conclusion

Incorporating this incremental cost penalty, incurred by the heater throttling, into the unit pricing would change the dispatch order of the plant relative to other sources of generation, enabling the unit to operate at its optimal capacity (sweet-spot) until other units are loaded. This would delay utilizing extraordinary measures such as heater throttling/bypassing to attain maximum generation until other resources had been loaded. If implemented, this would reduce fuel cost, have a positive impact on system heat rate, and improve unit reliability.

7.7 COOLING TOWER PERFORMANCE MONITORING

The cooling tower provides the interface of the cooling water with the environment. Degradation in its performance prevents the condenser and turbine from attaining optimal performance. Ensuring effective performance of a cooling tower requires monitoring the thermal performance of the equipment. However, the key to attaining consistent tower performance requires developing and maintaining a quality water chemistry program. Measuring thermal performance of the tower provides data about the effectiveness of the tower heat transfer. Measuring the chemical concentration and making adjustments to them provide the means to attain quality tower performance. The first line of defense is to develop and maintain a quality chemical program. The next step is to monitor the performance of the tower to ensure that the program is working effectively.

Chemical Monitoring and Control

With the advent and evolution of high efficiency film fills for heat transfer surface, cooling towers have achieved significant improvement in performance. However, due to its close spacing, fouling or scaling in film fills can be more dramatic and severe, in comparison to splash type of construction. This represents a significant challenge for cooling tower operators. A continuous monitoring and preventive program is imperative for maximum cooling tower performance.

A successful chemical treatment program is crucial for cooling towers with high efficiency fills as they are very susceptible to fouling, which can lead to the plugging of the fills and reduce tower performance. With high efficiency fills, silt and mud alone will not cause fouling, but biological growth alone can lead to substantial fouling. The combination of silt, mud and biological growth can lead to catastrophic fouling of the fills.

The biological activity is the initiating mechanism for fouling of high efficiency fills. If biological activity is uncontrolled, a layer of slime will form over the fill. The layer of slime is 'sticky'. As such any mud, silt and scale products that come into contact with the slime will adhere to it. This layer of mud, silt and scale will then cover the biological layer, making it much more difficult to destroy the biological activity because the mud layer shields the biological growth from the biological control chemicals. If left unchecked, the fills will become severely plugged by the accumulating mud, silt and scale.

Monitoring and controlling microbiological deposition and corrosion activity are imperative to sustain optimal performance of the cooling system. The following guidelines and best practices to achieve them are recommended.

Microbiological Monitoring

To monitor microbiological activity a combination of testing, mathematical predictors, and online monitoring tools can be used. If an increase in microbiological activity is detected, adjustments in the microbiological treatment should be made to minimize potential fouling problems. Specifically, adjustments will have to be made in the oxidizing biocide feed rate, non-oxidizing biocide shock feed dosage level, and/or bio-surfactant feed concentration.

- **Planktonic and Sessile Counts:** Planktonic and sessile microbiological counts should be performed routinely. The preferred method for sessile determinations is to install a stainless steel coupon in a coupon bypass rack for a minimum of one week. Once the coupon is removed, the sessile bacterial can be quantified using bacterial plate count tests. With the analysis of the plate counts, it is important that differences in the orders of magnitude be noted. Generally, microbiological problems are indicated by increases in plate counts by an order of magnitude from previous results.

- **BioScan ATP:** BioScan Adenosine Triphosphate (ATP) is a method to monitor the development of sessile biological growth in cooling water. It utilizes coupons in the corrosion bypass test rack as surfaces for biological growth, and the removal and dispersion of this growth into sterile water. This dispersed biofilm is then monitored for a chemical reaction which produces photons, or light, measured as Relative Light Units (RLU). This RLU measurement is proportional to the amount of ATP, or high energy phosphate bonds, found in the biofilm. In turn, the amount of ATP is proportional to the amount of microbiological cells and activity. This reading of cells and activity gives an indication of the biological growth. To minimize variations in the ATP measurements, BioScan ATP analyses should be conducted on the same day of the week and at the same time. When first interpreting BioScan results it is recommended that OEM water representatives assist with the monitoring until plant personnel are comfortable with the equipment and methods.

- **BioGEORGE System:** The BioGEORGE system is an online monitoring tool that provides real-time indications of biofilm activity. This is the preferred method for monitoring microbiological activity. The system consists of a 2-electrode probe, a cable and a controller. The probe is placed in the cooling water and monitors biofilm activity on its surface. Biofilm will form on the probe more rapidly than on cooling tower surfaces. As a result, maintaining the probe surface in a clean condition assures the cooling tower surfaces are also clean.

Figure 7-11: BioScan

For units with high efficiency tower fill, specific ranges of maximum values for planktonic and sessile biological RLU counts are given below. Note, plate counts should still be monitored for order of magnitude increases as this may indicate excessive biological activity before exceeding the limits shown below. Typically maximum plantonic and sessile counts are in the following ranges:

Planktonic (RLU) – 150 to 1000
Sessile (RLU/cm2) – 700 to 2500

Microbiological Control

The objective of any treatment program should be to expose any attached bacteria populations to an antimicrobial that is sufficient to penetrate and disrupt the biofilm. Generally, control of an already fouled system requires higher concentrations of intermittently fed treatment, while maintenance of a clean system can be achieved with low level concentrations in a continuous or regular feed. Therefore, it is important to follow an effective treatment program.

The biological treatment program is controlled by the amount of residual chlorine in the bulk water. Chlorine demand is the amount of chlorine consumed by other materials, such as microbiological organisms. Free available residual chlorine is the amount of chlorine that is left in the water after the demand has been satisfied. Free available residual chlorine is a check to determine if a treatment program is successful. If no residual chlorine exists, there are microbiological populations that still exist to consume chlorine and the treatment program is unsuccessful. The treatment program is deemed successful if residual chlorine exists.

Cooling tower systems can be treated with a continuous or intermittent program. In general, a system utilizing a continuous feed is to be maintained with a 0.1 – 0.5 ppm free chlorine residual. With a continuous feed, some type of dechlorination will need to be fed to remove chlorine from the cooling tower blowdown discharge. Another treatment option is an intermittent feed for closed cooling systems. This requires maintaining a 0.5 – 1.0 ppm free chlorine for one to four hours per day. For once through applications a 0.1 – 0.2 ppm total chlorine is required for two hours per day. It should be noted that maximum treatment times allowed are often dictated by a plant's environmental permit.

Non-oxidizing chemicals can also be effective in controlling microbiological use. These chemicals differ from oxidizing chemicals in the manner in which they kill the microbiological organisms. Quaternary ammonium compounds are an example of non-oxidizing chemicals. These chemicals destroy microbiological activity by damaging cell walls that lead to the death of the cell. However, for the quaternary ammonium compounds to be wholly effective they must be used in medium to high concentrations.

It is possible for sessile populations to become protected from bulk water chemistry with a secreted slime that can render oxidizing chemical programs ineffective. As such, one approach to control microbiological activity is to use both oxidizing and non-oxidizing chemicals. Also, the addition of bio-surfactants to oxidizing and non-oxidizing programs also improves sessile population penetrations by carrying the biocide to the microorganism.

Deposition Monitoring and Control

Beyond the requirements of a chemical treatment program, best practices that have been used successfully include the use of online monitors. When necessary, online monitors have been used to monitor both the deposition and microbiological control of the system with success. To monitor deposition, along with the required scaling indices calculations, the Bridger Scientific DATS is recommended. This provides a continuous measure of deposition as a function of heat transfer resistance. An increase in the heat transfer resistance is an indication of increasing deposition.

Figure 7-12: Bridger Scientific DATS

Deposition presents the most serious barrier to the transfer of heat through a surface and can be divided into two forms -- fouling and scaling. Fouling, due to suspended solids in the water, is the accumulation of water suspended materials on tower fills or heat exchanger surfaces. Scale is a dense coating of inorganic materials and results from the precipitation of soluble minerals from supersaturated water. The formation of scale most often occurs when the water becomes oversaturated or when water temperature increases. For some scale species, such as calcium compounds, solubility decreases with increasing temperature. As such, these deposits usually occur first at the outlet end of the condenser where the temperature is the highest. The rate of formation of the scale will depend on temperature, alkalinity or acidity, and the amount of scale forming material in the water.

The most common type of scale found in cooling water systems is calcium carbonate. This normally results from the breakdown of calcium bicarbonate and the degree of scaling depends on the levels of calcium hardness and alkalinity in the cooling water. It is important to note that as temperature increases, the solubility of calcium carbonate decreases. Another common type of scale is calcium sulfate, which results from increased levels of sulfates in the cooling water. The solubility of calcium sulfate also decreases with increasing temperatures. In particular, attention should be given to calcium sulfate scale for cooling towers utilizing sulfuric acid to control circulating water pH due to the increased risk for elevated sulfates in the water. Other types of scale found in cooling water systems include silica and magnesium compounds.

High efficiency fills have a significant risk for deposition, and it is particularly susceptible to fibrous contaminants and large particulates such as leaves or sawdust. Accordingly, it is recommended that sawdust not be used to plug condenser leaks. The fills can also be clogged from excessive airborne particles such as dust, coal or lime. It is extremely important to consider the fill type when designing the deposition treatment program and to rigorously monitor the fills for deposition problems.

Deposition monitoring can be carried out by measuring the Scaling Indices and/or visual inspections [7].

Scaling Indices: A formation prediction can be calculated with the use of indices such as the Langelier Saturation Index (LSI). This index is described as follows:

LSI=pH-pH
where:
pH is the measured water pH
pH_s is the pH at saturation in calcite or calcium carbonate and is defined as:
pH_s=(9.3 + A + B) -© + D)

Where:
A=(Log10 [TDS] -1)/10
$B = -13.12x\ Log_{10}\ (°C + 273) + 34.55$
$C = Log_{10}\ [Ca^{2+}\ as\ CaCO_3]\ -0.4$
$D = Log_{10}\ [alkalinity\ as\ CaCO_3]$

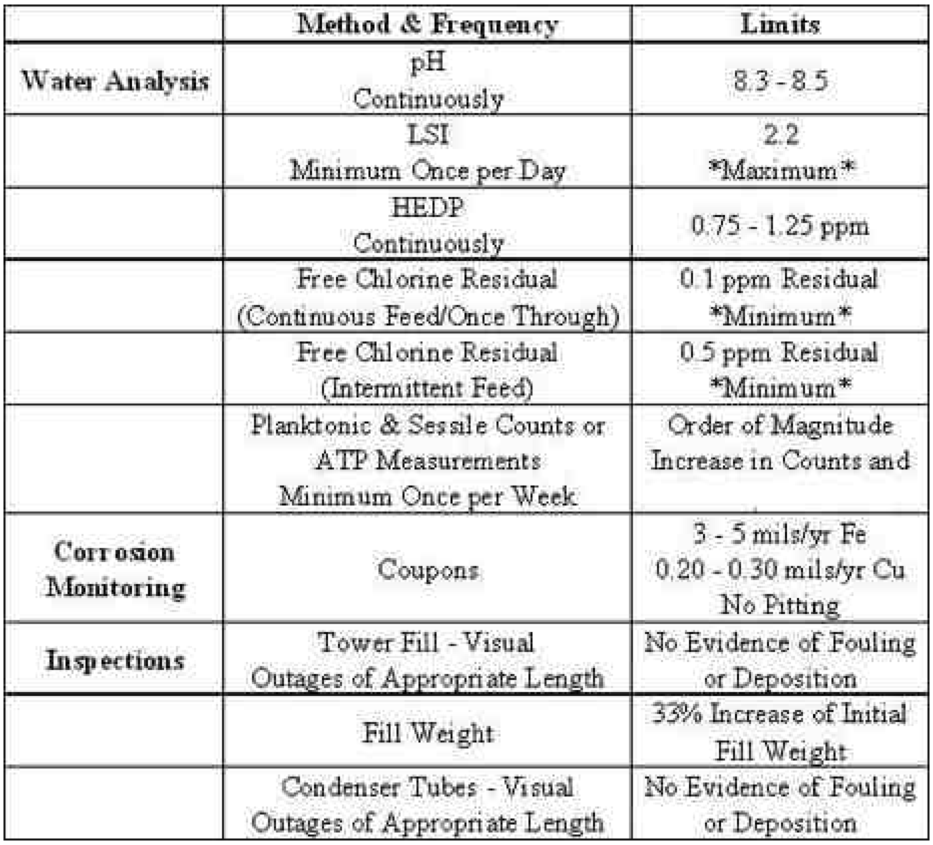
Where:
TDS = total dissolved solids (mg/l TDS)
°C = water temperature as degrees celcius
Ca^{2+} as $CaCO_3$= calcium hardness (mg/l as Ca^{2+} as $CaCO_3$)
alkalinity as $CaCO_3$= mg/l as $CaCO_3$

Nomographs are also available commercially that enable easy quick conversion of the parameters to LSI [7].

It is recommended that an LSI calculation be performed once a day, preferably in the afternoon when temperatures are warmest and conditions are most favorable for deposition. If the LSI calculation produces a positive value, the potential to form scale exists; and if a negative value is produced, no scale potential exists. At no time should an LSI value be greater than 2.2. If the values reach 2.2, changes in the treatment program need to be made immediately to decrease the potential for deposition.

Table 7-3 provides the cooling tower treatment program method, frequency and limits for water analysis, corrosion monitoring and inspection.

Table 7-3: Minimum Chemical Treatment Program Requirements



	Method & Frequency	**Limits**
Water Analysis	pH Continuously	8.3 - 8.5
	LSI Minimum Once per Day	2.2 *Maximum*
	HEDP Continuously	0.75 - 1.25 ppm
	Free Chlorine Residual (Continuous Feed/Once Through)	0.1 ppm Residual *Minimum*
	Free Chlorine Residual (Intermittent Feed)	0.5 ppm Residual *Minimum*
	Planktonic & Sessile Counts or ATP Measurements Minimum Once per Week	Order of Magnitude Increase in Counts and
Corrosion Monitoring	Coupons	3 - 5 mils/yr Fe 0.20 - 0.30 mils/yr Cu No Pitting
Inspections	Tower Fill - Visual Outages of Appropriate Length	No Evidence of Fouling or Deposition
	Fill Weight	33% Increase of Initial Fill Weight
	Condenser Tubes - Visual Outages of Appropriate Length	No Evidence of Fouling or Deposition

Tower Film Fill Inspection

Inspection a cooling tower enables direct visual feedback about the cleanliness of the tower fill. Performing these visual inspections can alert the utility of problems with the chemical treatment of the water before tower performance degradation becomes obvious. Inspection of the cooling tower fill should be planned during every scheduled outage of appropriate length. It is important to note that deposition and biological activity are more likely to occur in the lower fill levels. Due to this, the lower level of the tower fill should be inspected. It is not sufficient to only inspect the top layer of the fill.

There are several methods that can be utilized to provide an avenue to monitor and inspect tower fill [6].

1. Monitor the weight of a section of tower fill over time.
   a. The fill condition can be assessed through two methods of monitoring the weight of the fill.
      I. Monitor a section of tower fill with an online tower fill weight monitor, such as a digital tensile strength monitor on a test cell. (Although this potentially viable technology, has been implemented and field tested, the device tested experienced problems with durability).
      ii. Prepare a removable section of fill in the bottom layer that can be visually inspected and weighed on a regular basis.
2. High efficiency fill inspections can also be performed by visually inspecting the bottom of the fill utilizing mobile lifting equipment.
   a. Two methods can be used to inspect the bottom of the fill

      i. A narrow width tape measure can be inserted into the long narrow straight passages of the fill pack. The condition of the fill can be assessed by assessing the difficulty of moving the tape through and examination of the material output. This technique works best on straight passages, whether angular or vertical, in deep packs, with no change of direction or interface type blockages. This method is simple, inexpensive, and immediate, and is shown in Figure 7-13.

Figure 7-13: Fill Cleanliness Assessment with Tape Measure [6].

ii. A boroscope can be used to examine fill flutes from the bottom. This technique enables a more complete fill condition assessment in-situ. Results are shown in Figure 7-14.

Figure 7-14: Fill Cleanliness Assessment with Boroscope [6]

Tower Fill Cleaning

If a steady increase in film fouling is detected, the current treatment program should be modified to prevent further fouling. Should the weight gain exceed 33 percent of the initial clean fill weight action should be taken to clean fouled fill.

1. Online cleaning can be initiated. Several vendors offer online cleaning services and can tailor the cleaning process to the conditions present in the tower. One method entails addition of hydrogen peroxide in combination with a surfactant and polymer. Caution should be exerted when cleaning a very dirty fill as utilities have experienced large volumes of biofilm detach and totally plug sections of fill causing further performance degradation.

2. Offline cleaning can be accomplished by removing sections of fill and manually cleaning. This is very labor intensive; however, when utilized on a 220 MW unit it was very effective restoring the tower to near design performance. Utilizing this process requires that there be sufficient clearance above the fill to remove sections of fill since the bottom sections usually experience the most fouling.

Performance Monitoring

The following information on "Cooling Tower Performance Monitoring" is included to provide guidance with Tower monitoring [8]:

The recommended parameter for tracking cooling tower thermal performance is the cooling tower capability. The capability is defined as the ratio of the actual water flow rate to the predicted water flow rate at test conditions. The predicted water flow rate is the interpolated flow rate determined from the tower manufacturer's performance curves at the tested heat load, inlet wet bulb temperature, and fan motor power. The methodology used to calculate the capability, documented in the cooling tower performance test codes ASME PTC 23 and CTI ATC-105, is based on performance curves provided by the manufacturer which are usually provided as part of a new tower (or tower rebuild) bid package. An equally valid measure of performance, which also can be calculated based on the performance curves, is the cold water temperature at design conditions. Alternative methodologies such as Cooling Tower Institute (CTI) Toolkit (www.cti.org), allow the calculation of capability for cooling towers for which no performance curves are available. EPRI and some tower vendors also offer software and methodologies to calculate tower capability.

Historically, plants have used the tower 'approach' (the difference between the cold water temperature and the wet bulb temperature) to monitor thermal performance. This is much less desirable because the approach is a function of water flow and wet bulb temperature as well as the cooling tower thermal performance. Because the tower capability is a constant when operating within a reasonable proximity to the thermal design point, the tested tower capability can be used to predict the tower approach associated with the design values of heat load, water flow rate, and fan motor power.

Cooling tower capability is determined using measurements of the following parameters [8]

- Circulating water flow
- Fan motor power (for mechanical draft cooling towers)
- Hot water temperature
- Cold water temperature
- Inlet wet bulb temperature
- Inlet dry bulb temperature (for natural draft cooling towers)
- Barometric pressure

Specific installations may require the measurement of additional parameters. These include:

- Makeup water flow
- Makeup water temperature
- Blow down flow
- Blow down temperature
- Pump discharge pressure

These additional parameters are used to make minor corrections to the measured cold water temperature and will not usually impact the performance sufficiently to justify their measurement for monitoring purposes.

Most circulating water systems have no flow element to measure the circulating water flow. Installation of a flow element is costly and regular maintenance is required to assure accurate readings. Instruments to read wet bulb temperature (or equivalently dry bulb temperature and relative humidity) also require regular maintenance. Absent some catastrophic event (such as fill collapse or fill plugging due to solids accumulation), cooling tower performance tends to decline slowly over a period of years before reaching actionable levels. When performance has declined to the point that action is required, the necessary action (repair of water distribution or fill replacement) requires that at least one cell of the cooling tower be isolated to undertake the repairs. For these reasons, it is seldom cost effective to install a system to continuously monitor cooling tower performance. Instead, periodic tests of the cooling tower with test instruments are recommended.

The required frequency of testing is dependent on the specifics of water chemistry and cooling tower construction. Annual testing is almost always sufficient but less frequent testing can often be justified based on the results of the annual tests. Because a condenser performance test utilizes many of the same measured parameters as a cooling tower test and can also reveal significant deficiencies in the heat rejection cycle, conducting these tests in parallel is usually cost effective.

The accuracy requirements for test instruments to be used for periodic performance monitoring are summarized in Table 7-4.

Table 7-4: Accuracy Requirements for Test Instruments

Parameter	Units	Required Accuracy
Circulating water flow	%	5*
Fan motor power	%	5**
Hot water temperature	°C	0.17
Cold water temperature	°C	0.17
Wet bulb temperature	°C	0.28

*Typically circulating water systems are not equipped with flow measuring devices and pipes are not configured in a way conducive to accurate flow measurement.

**Although current and voltage are easily monitored, power factor is usually estimated and limits the accuracy of power.

Tests for contractual acceptance should be performed with higher accuracy instrumentation. If the monitoring program does not begin with an acceptance test, a performance test with high accuracy instrumentation should be considered at the initiation of the performance monitoring program [8].

Extracts from the paper “Heat Rejection Cycle Analysis: A Means to Recover Lost Megawatts and Reduce Greenhouse Gas Emissions” are included in this paper to provide additional insight into Cooling Tower Performance and Monitoring.

The Cooling Technology Institute (CTI) has a licensing program for the thermal performance testing of cooling towers. At the end of each year, statistics are compiled that show the operating performance of each tested tower versus the tower thermal design point. Most cooling towers are operating well below their design thermal capability.

One of the most telling statistics in the annual CTI testing report is the tested fan motor power consumption versus the design value for mechanical draft towers. On a historical basis, over 30 percent of the tested towers are operating with the fans more than 10 percent below their thermal design specification. Since the air flow through the tower is proportional to the cube root of the fan motor power and the air flow is directly proportional to the capability of the tower, this means that these towers are operating at about 5 percent below their rated capacity because the fan blades are not pitched to the appropriate level.

Because the air density increases in cold weather which increases the fan motor power consumption, some plants choose to operate their fan motors at reduced power levels to avoid encroachment on the motor service factor. However, the service factor rating is determined by the cooling requirements of the motor when exposed to high ambient temperatures. This means that for most plants, running the fans with low blade pitch is overly conservative and results in a recoverable loss of performance which can easily be avoided.

Other examples of recoverable cooling tower performance losses for any type of tower include leaking hot water bypass into the cold water basin, flow imbalance from cell-to-cell, and obstructed hot water distribution systems.

In a cross flow cooling tower, examples of easily corrected recoverable losses include plugged hot water distribution nozzles, missing nozzles, poor water balance over the tower, and inappropriate cold water basin depth. Missing, damaged or obstructed nozzles impair the hot water distribution over the fill media and disturb the necessary air/water distribution which is critical for efficient cooling tower performance. When cross flow towers are operated with low water levels in the hot water distribution deck, the water will “cone” down through the fill. This “coning” results in areas of dry fill alternating with locally flooded fill. Air drawn through the tower will preferentially go through the dry areas with low pressure drop and the overall performance of the cooling tower can be severely impacted. Examples of irrecoverable cooling tower performance losses include step changes in performance after fill is damaged due to icing events, fill support failure, structural failure, hydraulic excursions, or other physical problems. Performance problems can result when counter-flow water distribution laterals, lateral end caps, or cooling tower nozzles are dislodged and the resulting water deluge erodes the fill beneath. Biomass or silt accumulation in cooling tower fill results in a more gradual or seasonal loss in performance that is often overlooked until the unit that it serves is curtailed in summer time operation.

Heat Rejection Cycle Analysis

Because the water flow rate is a performance parameter that is common to the condenser, cooling tower, and circulating water pumps, and because the water flow rate is usually the most difficult parameter to measure when testing these components, it is cost and labor effective to evaluate the entire heat rejection cycle at one time. In addition to water flow rate, other cooling tower measurements include tower wet bulb temperature, cold and hot water temperatures, and fan motor power. Many of these measurements are also used to evaluate the condenser performance. Additional measurements for the condenser evaluation include the condenser pressure and condenser inlet and outlet temperatures. Additional measurements for the pump evaluation include pump discharge pressure and lift or suction side static pressure referenced to a common datum.

Water Flow Rate Measurements

For most systems, water flow rates can be measured by pitot tube traverse. Pitot tubes are best suited for pipes with long straight runs that have well developed flow profiles. While pitot tubes can be used to measure water flow rate in pipes exceeding 3m (10 ft) in diameter, because of access limitations, the pitot taps for flow measurement are often installed in the cooling tower risers. For large multi-cell towers, this may require that flow measurements be made in 15 or more risers over a two day period. Because the objective is to have well developed flow profiles at the measurement locations, the pitot taps are best installed about ¾ of the vertical riser height between the isolation valve at the bottom of the riser and the bend where the riser enters the tower.

Alternately, flow measurements can be made via dye-dilution techniques. Dye dilution is a very accurate flow technique that is best suited for once-through systems and can be used when there are very short runs of straight pipe length or where the pipe cannot be accessed or modified for the installation of pitot taps.

Wet Bulb Temperature Dependency

The impact of the heat rejection cycle on the overall plant performance varies with the cooling needs of the plant. As the wet bulb increases, the cold water temperature supplied to the condenser increases and the back pressure on the turbine increases. Units with significantly underperforming heat rejection cycles are often curtailed in the summer to prevent plant trips due to high back pressure. This curtailment occurs during peak demand when generating capacity is worth a premium, plant capacity is worth the most to the generator, and lost capacity is extremely expensive to replace.

The Cost of Plant Mal Performance

Considering a hypothetical 650 MW coal fired plant with an 85 percent load factor and coal costs of USD 50 per ton, the cost of neglecting the heat rejection cycle is illustrated in Table 7-5.

Table 7-5: Heat Rate and CO_2 Increase Associated with Underperforming Heat Rejection Equipment

Change in Component Performance	Change in HR	Annual HR Cost	Increase in CO_2
10% Condenser Cleanliness	30 BTU/kWh	USD 330,000	17,000 (TPY)
10% Cooling Tower Capability	15 BTU/kWh	USD 165,000	8,500 (TPY)
10% Circulating Water Flow	20 BTU/kWh	USD 220,000	11,400 (TPY)

When plants are not limited by the maximum fuel heat input, the increased heat rate causes an increased use of fuel which is reflected by an increase both in the cost of the fuel and in carbon dioxide emissions. The increase in carbon dioxide emissions associated with the change in heat rate can be calculated by

$$CO_2 \quad \frac{8760}{2000} \quad \frac{44}{12} \quad MkW \quad L_f \quad C_f \quad HR$$

?CO_2 = change in CO_2 emissions, TPY
MkW = plant capacity, kW
L_f = load factor
C_f = carbon fraction in fuel
?HR = change in heat rate, Btu/kWh

Nuclear power plants and the steam turbine section of combined cycle units operate on a fixed heat input. Therefore, an increased heat rate for these units represents a decrease in power output. Coal fired units that are boiler limited may also have a reduction in available power output. The annual heat rate costs do not consider the economics of summertime curtailment, emissions credits, or goodwill.

Calculation Methodology Overview

The following outline describes the procedure that is used to calculate the impact of the heat rejection cycle on the unit heat rate.

1. The capability of the cooling tower is evaluated through the measurements of water flow rate, hot water temperature, cold water temperature, inlet wet bulb temperature, and fan motor power (mechanical draft towers).

2. The tested cooling tower capability is used to predict the tower's exiting cold water temperature as a function of inlet wet bulb temperature for the design heat load at the tested water flow rate. Note that for most systems, the cooling tower cold water temperature is the same as the condenser inlet temperature.

3. The condenser inlet temperature, outlet temperature, water flow rate, and turbine pressure are used to determine the condenser cleanliness.

4. Using the thermal kit for the turbine, a curve can be generated that expresses the heat rate as a function of inlet wet bulb temperature for the system at its tested condenser cleanliness, tower capability, and measured water flow rate. The impacts on turbine back pressure can also be evaluated for each component.

When the plant has this component specific performance information and cost estimates for component refurbishment, the plant has tools for the economic analysis of heat rate driven payback time associated with the refurbishment to original thermal design performance for each of the mal-performing components. Emissions credits, reduction in emissions based fees, and similar cost savings can also have an impact on payback time. Avoidance of a summertime curtailment is a large economic incentive for immediate refurbishment of the bottleneck in a heat rejection system [4].

In item 4, Hennon and Wheeler have suggested a potential enhancement to the baseline heat rate described in Chapter 7.3. Although this is certainly a viable concept, circulating water temperature is easily measured, and the backpressure curves as a function of circulating water temperatures are well defined. Therefore the author recommends developing baseline heat rate curves as a function of circulating water temperatures and monitoring wet bulb temperatures to track tower performance. Hennon and Wheeler go on to present the methodology for calculating tower performance as follows:

Cooling Tower Performance

Cooling tower manufacturers' performance guarantees are usually presented in the form of Performance Curves. Mechanical draft cooling tower performance curves present cold water temperature as a function of inlet wet bulb temperature for various cooling ranges and water flow rates at a design fan motor power. These curves present the performance of a tower that is operating at 100 percent capability.

Cooling tower capability is defined by the following equation:

$$C \quad \frac{Q_a}{Q_p} x100$$

where

Q_a = Adjusted water flow rate

Q_p = Predicted water flow rate

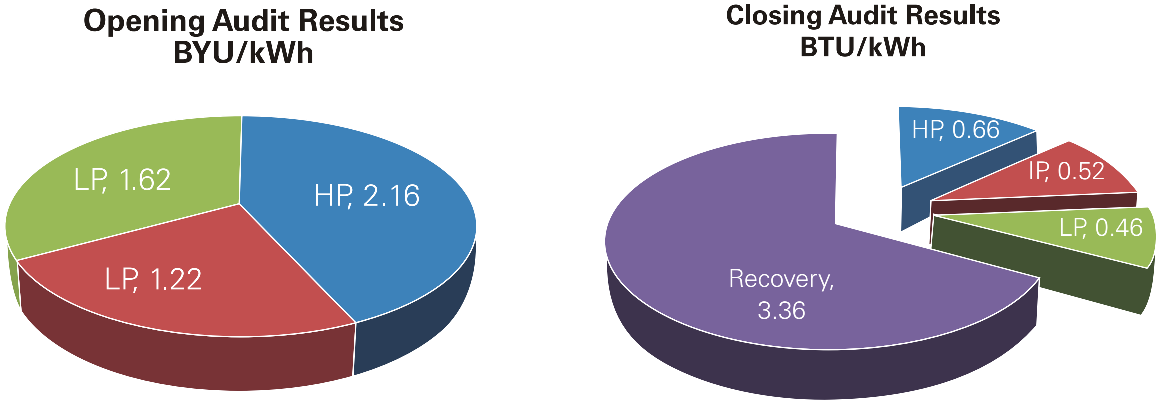
The predicted water flow rate is the water flow rate derived from the performance curves for a tower operating at design performance (100 percent capability). A tower that is operating at design performance would cool the predicted flow rate to the design cold water temperature when the tower is operated at the design values for inlet wet bulb temperature, cooling range, and fan motor power. A tower capability of more than 100 percent indicates that the tower can cool more water flow to the design conditions than guaranteed (alternately it can provide colder water at the design flow rate). A tower capability of less than 100 percent indicates that the tower cannot cool the design water flow rate to the design conditions. Most cooling towers are performing well below 100 percent capability [4].

7.8 STEAM PATH AUDITING

Operating turbines in a cost effective manner, while maximizing reliability, requires a quality turbine maintenance program. Inefficient turbines can significantly impact the unit heat rate, which impacts the fuel cost. Implementing a quality condition-based maintenance program that regularly evaluates unit operation can extend the duration between outages and help in recovering the losses. This section presents protocols to accomplish these tasks [10].

Encotech has compiled data from 19 turbines inspection and repairs that is shown as follows. The Pie charts shown in Figure 7-15 display the aggregated heat rate degradation data that occurred prior to opening 19 turbines. The closing audit results display the heat rate improvement experienced after maintenance had been performed.

Figure 7-15: Heat Rate Degradation for the HP, IP, and LP Casings for Opening and Closing Steam Path Audits.



Effective steam path auditing entails on-line monitoring, outage equipment assessment including inspection and sampling, cost effective repair of the problems found, and assessment of the repair effectiveness through continuous monitoring or testing.

The following Condition-Based Overhaul protocol contributed by TVA that was originally prepared for NTPC in conjunction with USAID GEP project provides a good example of the process. This provides both a methodology to evaluate the relationship of performance to damage, and provides a macro view of the areas that should be evaluated and repaired during the overhaul. A root cause assessment of some catastrophic failures is also provided [13].

Condition-Based Overhauls

Condition-based overhaul (CBO) philosophy requires the utility management team to commit to the development of critical thinking skills. These skills are necessary for understanding the root cause of degradation as well as the cause and effect relationships between turbine-generator (T-G) systems and the components degradation processes.

T-G condition assessment is an ongoing process that is updated over the life of the units. There are three phases to the condition assessment process:

1. **On-line Condition Assessment**

   This process is the most challenging and requires establishing Fleet- and Unit- Specific Health Status Indicators, referred to as unit Critical Indicators (CIs). Monitoring unit CIs provides on-line information about unit performance, condition and potential threats to generation.

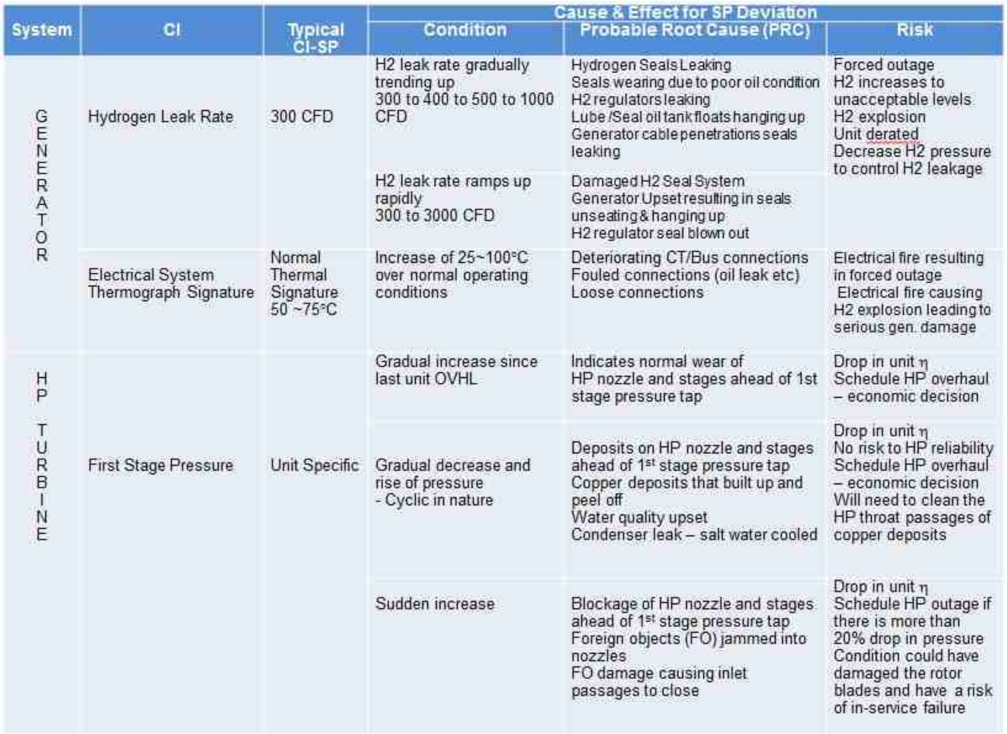
   NTPC needs to establish fleet-specific CIs in concert with the T-G fleet major equipment OEMs and T-G consultants experienced in on-line condition assessment processes. System design basis values, operating limits and their respective set points (SP) would need to be established for each CI.

   Depending on the fleet/unit design and the unit state-of-art instrumentation, the unit-specific CIs and their SP limits may need modification. For example, unit with shaft rider probes for monitoring the T-G shaft vibration cannot provide shaft phase angle shift (), an essential CI for establishing changes in the T-G shaft dynamics.

   An example of some typical system/component CIs, typical OEM recommended SP limits and their cause and effect relationship to the unit condition are listed in Table 7-6.

Table 7-6: Examples of Typical T-G Critical Indicator Set Points Cause & Effect of SP Deviation

CI = Critical Indicator   CI-SP = Critical Indicator Set Point   CFD = Cubic feet per day



System	CI	Typical CI-SP	Cause & Effect for SP Deviation		
			Condition	Probable Root Cause (PRC)	Risk
GENERATOR	Hydrogen Leak Rate	300 CFD	H2 leak rate gradually trending up 300 to 400 to 500 to 1000 CFD	Hydrogen Seals Leaking Seals wearing due to poor oil condition H2 regulators leaking Lube /Seal oil tank floats hanging up Generator cable penetrations seals leaking	Forced outage H2 increases to unacceptable levels H2 explosion Unit derated Decrease H2 pressure to control H2 leakage
			H2 leak rate ramps up rapidly 300 to 3000 CFD	Damaged H2 Seal System Generator Upset resulting in seals unseating & hanging up H2 regulator seal blown out	
	Electrical System Thermograph Signature	Normal Thermal Signature 50 ~75°C	Increase of 25~100°C over normal operating conditions	Deteriorating CT/Bus connections Fouled connections (oil leak etc) Loose connections	Electrical fire resulting in forced outage Electrical fire causing H2 explosion leading to serious gen. damage
HP TURBINE	First Stage Pressure	Unit Specific	Gradual increase since last unit OVHL	Indicates normal wear of HP nozzle and stages ahead of 1st stage pressure tap	Drop in unit η Schedule HP overhaul – economic decision
			Gradual decrease and rise of pressure - Cyclic in nature	Deposits on HP nozzle and stages ahead of 1^{st} stage pressure tap Copper deposits that built up and peel off Water quality upset Condenser leak – salt water cooled	Drop in unit η No risk to HP reliability Schedule HP overhaul – economic decision Will need to clean the HP throat passages of copper deposits
			Sudden increase	Blockage of HP nozzle and stages ahead of 1^{st} stage pressure tap Foreign objects (FO) jammed into nozzles FO damage causing inlet passages to close	Drop in unit η Schedule HP outage if there is more than 20% drop in pressure Condition could have damaged the rotor blades and have a risk of in-service failure

Where applicable, utilities can either utilize the OEM-recommended CIs and their associated SP limits or modify them to reflect their operational experience and level of risk averseness. Collecting and evaluating the fleet data, and evaluating SP deviations and their associated impact on unit performance, will provide the basis for the utility to improve their fleet-specific SP limits.

2. Assessment During Unit Overhaul

Utilities usually conduct some level of component damage assessment during the discovery and inspection phase of a planned or forced outage. During an overhaul (planned outage) the condition assessment process should commence several weeks prior to the unit shutdown. The T-G Overhaul condition assessment process involves the following phases:

- Pre-Outage Shutdown Checks
- Unit Coast-down Checks
- Turbine Valves Hysteresis Checks
- Unit Disassembly Checks
- Unit Steam Path Damage Assessment
- Bearings Condition Assessment
- Generator Assessment

The assessment process provides information essential regarding system/component condition, impact on unit reliability and the basis for developing the Run/Repair/Replace (RRR) decisions necessary to effectively manage the T-G fleet.

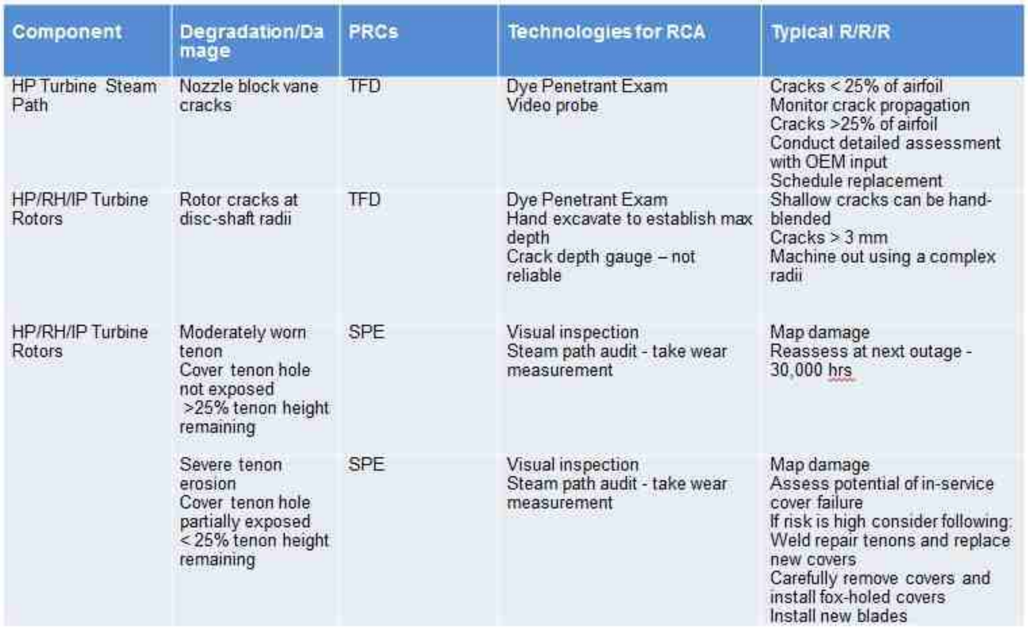
Over the past decade, component damage assessment experts in the United States have developed an in-depth understanding of the T-G component damage, potential root cause of damage, its potential impact on the unit's reliability and the basis for developing cost effective RRR recommendations. These component damage assessment efforts have been supported through a broad range of component specific studies conducted by various consultants specializing in component damage specific issues. EPRI is a significant player in this field by sponsoring technologies targeted towards furthering the understanding of the root cause (RC) of the component damage.

A paradigm shift by many U.S. utility management teams is occurring to support and encourage their T-G organizations to take an engineered approach to evaluating the component damage, associated risks and the cost benefits of the available options. There is a saying in the U.S. power industry that no one ever got fired for proposing an OEM recommendation. Outlined in Table 7-7 are typical T-G damage/degraded conditions, RC of degradation and, where applicable, technologies utilized to establish root cause of failure.

3. Assessment Part of T-G Forced Outage/Investigation

T-G forced outages (FO) are inevitable, however, they provide an excellent opportunity to understand the root cause of the FO and form the building blocks of the RRR decision process. Outlined in Table 7-8 are some high-profile T-G failures experienced at some U.S. utilities, tools utilized to evaluate the RC of the failure, and RRR options developed and implemented.

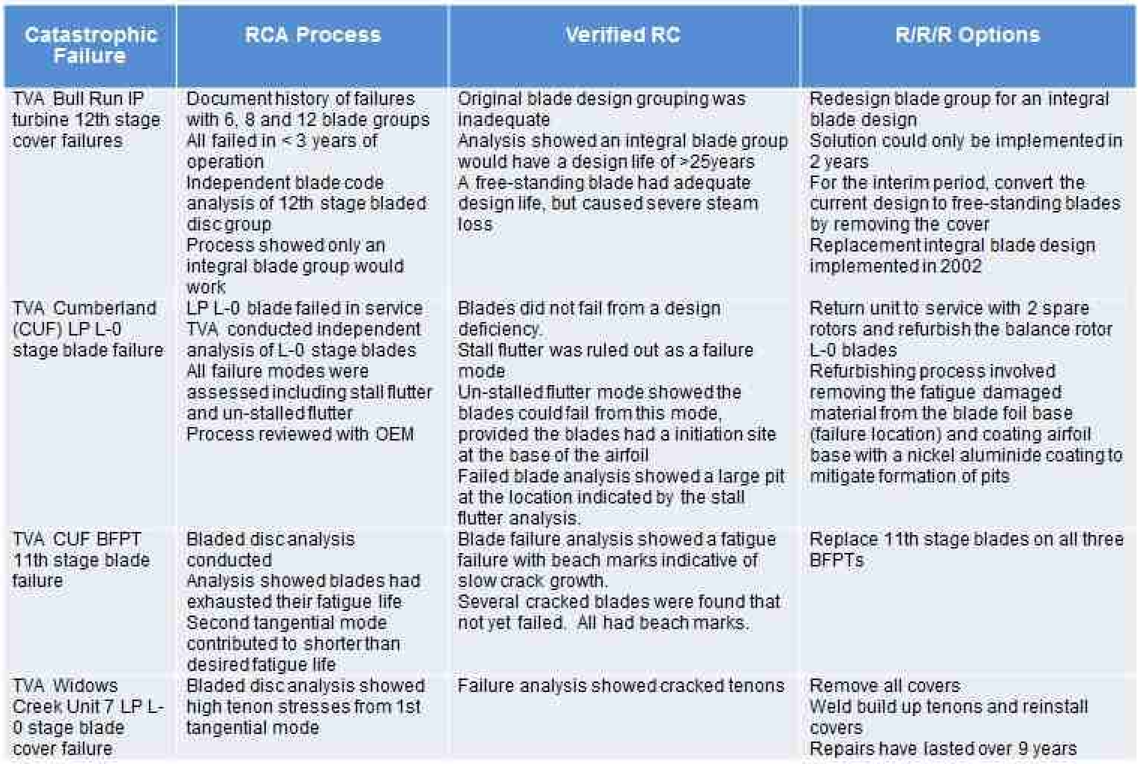
Table 7-7: Catastrophic T-G Failures at U.S. Utilities – RCA Process – PRCs – R/R/R Options



Component	Degradation/Damage	PRCs	Technologies for RCA	Typical R/R/R
HP Turbine Steam Path	Nozzle block vane cracks	TFD	Dye Penetrant Exam Video probe	Cracks < 25% of airfoil Monitor crack propagation Cracks >25% of airfoil Conduct detailed assessment with OEM input Schedule replacement
HP/RH/IP Turbine Rotors	Rotor cracks at disc-shaft radii	TFD	Dye Penetrant Exam Hand excavate to establish max depth Crack depth gauge – not reliable	Shallow cracks can be hand-blended Cracks > 3 mm Machine out using a complex radii
HP/RH/IP Turbine Rotors	Moderately worn tenon Cover tenon hole not exposed >25% tenon height remaining	SPE	Visual inspection Steam path audit - take wear measurement	Map damage Reassess at next outage - 30,000 hrs
	Severe tenon erosion Cover tenon hole partially exposed < 25% tenon height remaining	SPE	Visual inspection Steam path audit - take wear measurement	Map damage Assess potential of in-service cover failure If risk is high consider following: Weld repair tenons and replace new covers Carefully remove covers and install fox-holed covers Install new blades

Table 7-8: Catastrophic T-G Failures at U.S. Utilities – RCA Process – PRCs – R/R/R Options

SPE: Solid Particle Erosion TFD: Thermal Fatigue Damage HCF: High Cycle Fatigue PRCs: Potential Root Causes



Catastrophic Failure	RCA Process	Verified RC	R/R/R Options
TVA Bull Run IP turbine 12th stage cover failures	Document history of failures with 6, 8 and 12 blade groups All failed in < 3 years of operation Independent blade code analysis of 12th stage bladed disc group Process showed only an integral blade group would work	Original blade design grouping was inadequate Analysis showed an integral blade group would have a design life of >25years A free-standing blade had adequate design life, but caused severe steam loss	Redesign blade group for an integral blade design Solution could only be implemented in 2 years For the interim period, convert the current design to free-standing blades by removing the cover Replacement integral blade design implemented in 2002
TVA Cumberland (CUF) LP L-0 stage blade failure	LP L-0 blade failed in service TVA conducted independent analysis of L-0 stage blades All failure modes were assessed including stall flutter and un-stalled flutter Process reviewed with OEM	Blades did not fail from a design deficiency. Stall flutter was ruled out as a failure mode Un-stalled flutter mode showed the blades could fail from this mode, provided the blades had a initiation site at the base of the airfoil Failed blade analysis showed a large pit at the location indicated by the stall flutter analysis.	Return unit to service with 2 spare rotors and refurbish the balance rotor L-0 blades Refurbishing process involved removing the fatigue damaged material from the blade foil base (failure location) and coating airfoil base with a nickel aluminide coating to mitigate formation of pits
TVA CUF BFPT 11th stage blade failure	Bladed disc analysis conducted Analysis showed blades had exhausted their fatigue life Second tangential mode contributed to shorter than desired fatigue life	Blade failure analysis showed a fatigue failure with beach marks indicative of slow crack growth. Several cracked blades were found that not yet failed. All had beach marks.	Replace 11th stage blades on all three BFPTs
TVA Widows Creek Unit 7 LP L-0 stage blade cover failure	Bladed disc analysis showed high tenon stresses from 1st tangential mode	Failure analysis showed cracked tenons	Remove all covers Weld build up tenons and reinstall covers Repairs have lasted over 9 years

Scheduled Unit Overhaul Assessment

Since the assessment during unit overhaul is an essential part of an effective condition-based maintenance program, the following protocol is included in this report. Turbines are expensive to overhaul and this process can be implemented every 1-2 years and possibly avoid unplanned expensive turbine overhauls.

AEP's guidance focuses on deposit collection and analysis while also providing some insight into other important inspections.

Scale deposits and blade failure due to cracks are key reasons for poor turbine efficiency. These aspects of turbine operation are especially critical for supercritical plants. A rigorous steam path inspection during outages provides an important tool for maintaining optimal turbine performance. A thorough inspection should include visual inspection of last stage blade condition, blade deposits, exhaust hood, insulation, etc. Proper and timely inspection enables early detection of turbine problems. The key to reliable turbine operation is attention to steam path details. Adherence to proper chemical treatment of water, refurbishing turbines once every 7-20 years, and outage inspection of steam path are paramount to reliable turbine operation and reduced overhauls.

Minimizing expensive turbine overhauls requires a thorough inspection of the parts of the turbine that can be observed during annual outages. This enables detection of possible chemical balance issues and turbine blade issues.

LP turbine last stage blading is an area that can easily be inspected at this time. Although this inspection only provides a sampling of the LP turbine condition, it can alert the utility to significant LP turbine problems, thus preventing expensive turbine overhauls. Mechanical Dynamics & Analysis, Ltd. has a wealth of experience repairing turbines and shares some general insights about areas that can be troublesome. Hatcher comments that supercritical units are also likely to have more deposits in the LP that can cause stress corrosion cracking (SCC) in the wheel dovetails. He reports seeing many examples of SCC on L-2, L-1 dovetails, L-0 Blade vanes and dovetail pins (Hatcher). Last stage blades are an area that should be inspected during every scheduled outage. Recommended areas that should be inspected during each scheduled outage are as follows:

1. **Inspect last stage blades**

    a. Inspect main turbine last stage blades. Inspection to consist of a visual inspection for loose, cracked, and/or missing tie wires and an NDE of accessible surface of blades (e.g. magniflux, zyglo or CREG probe).

    b. If a failed turbine blade should be observed, the following procedures should be adhered to:

        i. Protection of Fracture Surfaces

        In addition to properly identifying the location of the failed blade, it is extremely important that the fracture surface be protected from contamination. A clean fracture surface can be very helpful in determining the cause of the failure. Depending upon what we learn from a fracture, it may be possible to alter repairs or modify the equipment to prevent a reoccurrence. Therefore, when a failure occurs, it is important that the surface be protected from fingerprints, oil, grease, solvents, aluminum oxide, nondestructive testing solutions and solvents of any kind. Generally the surface should be covered with clean plastic and wrapped in cloth to prevent contamination and further impact damage to the fracture surface, unless specific instructions have been provided by the OEM failure analysis lab. It is important to prevent the fracture surfaces from further damage by keeping them from coming in contact with each other.

        ii. Tracking blade failures by developing a system to consistently identify turbine blade is also very important.

2. **Inspect turbine for deposits**

a. The steam turbines of all vendors typically experience corrosion and deposit buildup problems. Buildup of deposits on turbine blades lowers the mechanical and thermodynamic efficiency of turbines, resulting in costly heat rate increases and reduced generating capacity. It can also lead to overloading and failure of thrust bearings, rotor imbalances and vibrations. Blade failures are most commonly caused by the formation of pitting during out of service conditions which leads to corrosion fatigue or stress corrosion cracking blade failures as these pits align and form cracks during operation.

Figure 7-16: Turbine Deposits

b. It is very important to maintain an ongoing record/log of the chemical environment of stationary or rotating turbine blades. The turbine deposit characteristics and analysis described below provides only a portion of that data. Providing an ongoing record of the chemical environment requires much more. This record should chronicle the environment to which the turbine is exposed when it is out of service, the normal chemical operating guidelines, any chemical excursions that have been experienced when the machine is operating, etc. Changes in operating conditions, such as lower minimum loads, or backpressure excursions can also provide useful information when analyzing a turbine. This record should enable the owner operator to correlate the relationship between turbine reliability and efficiency and steam impurity concentrations. Use of such data can advance understanding of steam turbine corrosion, erosion, and scale/deposit formation, leading to better steam purity and boiler water operating limits.

c. The recommendations for collecting and submitting turbine deposit samples for analysis are as follows:

   a) Samples should be taken from the turbine during any turbine overhaul. Sampling should be done prior to blast cleaning or exposure of the turbine elements to plant dust or dirt. Deposit samples should be carefully scraped into nonreactive containers such as polyethylene bags or plastic bottles. Wash water samples should be collected in plastic bottles. Digital pictures should be taken of the areas to be sampled. These pictures need to include month, year, unit, which turbine blade section, and blade row.

b) Deposit weights of at least 0.50 grams should be collected if possible. If deposits are noticeable, but they do not have enough solid mass to obtain a dry sample, the turbine can be washed with deionized water and the wash water can be collected for analysis. The wash water sample should contain the dissolved constituents that are present in the deposit. Dry and/or liquid samples are to be sent to a lab for analyses.

c) It is important to note such items as the color, thickness and amount of deposit as well as the in-place condition (such as layer type, loose, flaky, adherent, etc.). Any other pertinent data should be included with the transmittal. Deposits analysis should be requested.

d) It is important to note the location of the deposits. Additionally, digital pictures of the turbine are to be taken and included in the final report. All turbine deposits should be sampled whenever the turbine is inspected and the stationary and/or rotating blades are available for sample collection. Analytical data will be held until all descriptive information listed above is received, so that it can be included in the final report.

3. **Inspect exhaust hoods**
    a. Inspect/repair steam seal piping bracing in exhaust hoods.
    b. Inspect/repair exhaust hood sprays and piping braces.
    c. Flush exhaust hood spray piping and visually inspect the spray pattern to insure spray through all spray nozzles.
    d. Calibrate exhaust hood thermocouples.
    e. Conduct NDE of flow guide ring bolting. Replace defective bolts.
    f. Conduct NDE of cone extension bolts in low pressure exhaust hoods.
    g. Inspect extraction piping expansion joints in exhaust hoods.
    h. Inspect/repair vacuum pumps or steam jet air ejectors.
4. **Inspect / repair main turbine shell, valve, and piping insulation.**
5. **Complete authorized OEM recommendations.**
6. **Inspect/repair/calibrate turbine supervisory instrumentation.**

After the outage has been completed the following activities should be completed

1. Perform standard interlock tests prior to starting the unit.
2. Monitor turbine vibration levels during startup and while loading unit and perform any approved balance refinements. Take full load vibration data prior to removal of unit for a major scheduled outage.

3. Conduct stage pressure differential test, heat rate test, turbine efficiency test and shaft packing leakage test in conjunction with the recommended testing frequency schedule and the turbine inspection schedule.

Turbine Repair

If a quality condition based maintenance program has been employed, turbine outages will be infrequent because problems will be detected early and corrective action will be applied. However, periodically turbine overhauls will be required and the most cost effective protocols for repairing wear must be utilized.

Modular Replacement

A practice that can significantly expedite the completion of outages is modular replacement of components. The modular concept entails owning spare components that can be refurbished while the unit is operating. An example of this might be to possess a spare HP turbine that has been refurbished and preassembled. All work can be completed on the turbine in a more controlled environment, by a team of experts. This team can be located in a central location and has the experience and expertise to observe and correct problems so that they do not recur. Some US utilities with several units that utilize the same components, such as AEP, have reaped significant rewards by implementing this process. It not only expedites planned outages, but provides ready refurbished components when unplanned failures occur. Although an in-house team provides the aforementioned advantages, the modular concept can also be accomplished through the use of OEMs or other vendors.

Encotech has identified several best practices that can be adopted to optimize turbine steam path audits. These practices address various packings, leakages, flow path issues, and surface roughness.

Packings (Interstage and End)

Maintenance to improve interstage packing losses typically consists of replacing packing rings or sharpening packing teeth. In circumstances where the packings are rubbed, but the packing clearance is less than 25 mils, it is generally most economical to not replace the packing. Restoring the heat rate economically for the least cost can best be accomplished by sharpening the teeth to remove burrs, thereby restoring a sharply squared tooth profile.

Restoring clearances on non-retractable packings to less than design have a greater likelihood of rubbing in service. Since a rubbed packing tooth has a leakage approximately 20 percent higher than a sharp packing tooth, any benefit from a reduction in flow area due to a tightening the clearance is quickly negated by increased flow through the rubbed teeth. Concerns about tight clearances also apply to radial spill strips. Clearances that are more than 5 mils too large or too small will decrease performance and the benefit-to-cost ratio.

Miscellaneous leakages

Although snout ring leakage will increase power output, it can have a significant detrimental effect on heat rate.

Flow path damage

The turbines in this survey experienced 0.5 percent heat rate degradation as a result of flow path damage and returned to service with 0.16 percent heat rate degradation. Most audit damage consisted of SPE in the first stages of the HP & IP turbines, and deposits on the later stages of the IP and LP turbines.

Hatcher comments that supercritical units are more prone to passing boiler tube exfoliate into the steam path, which results in more solid particle erosion at the HP & IP inlet sections. HP first stage nozzle vanes often experience serious SPE after 5-6 years of operation. He has also seen severe solid particle erosion on the first HP, first IP, and LP Tenons. He recommends UT of the nozzle box and any 90 degree bends to determine wall thickness. Also vane tip and underside of cover erosion in the back of the HP [15].

Solid particle erosion (SPE) is caused by scale that exfoliates from the superheater due to stresses developed within the superheater. The scale results from oxide that builds as the superheater ages. The stresses that remove this scale are generally caused by temperature changes caused by cycling the unit or by rapid temperature excursions. The scale results from iron oxide (magnetite) that builds up on the internal surfaces of the tubes. When temperature excursions occur, cracks will develop in the magnetite due to the stresses imposed and the oxide will crack off and be carried by the steam to the turbine. Chemical cleaning of the superheater is a means that can be utilized to remove the scale; however, most U.S. utilities have not engaged in this practice due to the expense and risk involved. One plant had some limited success by passing large blasts of air through the superheater to drains prior to startup to remove some of this scale. Means to easily mitigate SPE are not readily available.

Encotech provides blading repair guidance as follows:

Utilities have an opportunity to improve flow path damage recovery by specifying the following for blading repairs:

1. Restore the aerodynamic profile of the partitions
    - Form a template from an undamaged partition
    - Check for flat spots (Dyer gage)
    - Restore the trailing edge thickness to design (typically 15 to 30 mils depending on the stage)
    - Remove bumps, ridges, and high spots

2. Use a strong rebuilding material. (The authors have witnessed cases where previous repairs have been completely eroded away by the next outage.)
3. Perform a 100 percent area check on repaired stages
    - Take root, pitch, tip, and blade height measurements on all partitions
    - Keep the variation in area of individual partitions within the manufacturer's tolerance
4. Restore the surface finish
    - Assure there is a smooth transition between the original material and the built-up material
    - Polish the partitions to a 64 center line average (Ra) - particularly on the stationary blading suction surface at the trailing edge.
    - Do all final polishing or machining in the direction of flow
    - Smooth the end walls

Surface Roughness

Opportunities exist for utilities to recover more of their surface roughness losses:

1. Grit blast using the finest grade grit that will do the job. For example, 300 aluminum oxide grit may remove deposits and clean the surface as well as 200 aluminum oxide grit, but the 300 grit will leave a smoother surface.
2. Grit blast in the direction of flow. On a microscopic level, the surface roughness peaks should be bent over in the direction of flow for the least amount of friction. If polishing, do all finishing work in the direction of flow for the same reason.
3. Pay especially close attention to the stationary blading suction surface at the trailing edge since roughness on that surface has the greatest impact on efficiency. Fortunately, this surface is also the most accessible.
4. Surface finish can be improved by following aluminum oxide grit blasting with glass bead blasting.

Implementing the guidance provided in this chapter will enable a utility to more effectively operate and maintain the turbines in its fleet.

7.9 ULTRASONIC LEAK DETECTION CASE STUDY

Case Study 1

Background: This is a U.S. 260 MW drum unit with a main condenser and a Boiler Feed Pump Turbine (BFPT) condenser. The BFPT condenser is comprised of two halves that can be isolated by closing the circulating water valves feeding one half with the unit on-line. The plant has historically used cling wrap (low density polyethylene), and/or shaving cream to locate leaks on-line.

Problem: On the Wednesday morning around 11:00 AM several conductivity points started increasing on a 260 MW and indications were that the source of contamination was the BFPT condenser. Shortly thereafter, the drum blowdown was opened to try to clean up the condensate and load was reduced. At 11:42 AM the unit was curtailed to 150 MW due to a suspected circulating water leak in the BFPT Condenser. This amounted to a 110 MW curtailment during peak load demand.

Solution: Operations started isolating the condenser halves one at a time to determine which had the leak. The north half condenser was identified as the source of the leak and a clearance was placed in effect for maintenance to locate and repair it.

The first step in this process is to raise and lower the water level to try to narrow down the approximate area the leak is in. This is done by watching for an increase in conductivity and marking the water level at that point, which due to the time lag before the conductivity increases is far from an exact determination.

The next step is to use cling wrap to cover the tube sheet on one end which will increase the vacuum on the other end to enhance leak detection. Shaving cream and cling wrap are then placed on the other end in sections, and personnel try to locate which tube is leaking by watching the shaving cream and cling wrap for indications of air being pulled in. Many times this works well but in this case it did not; most likely because it was a small leak.

Since these approaches had been unsuccessful, maintenance began running a water lance through each tube and watching the conductivity to see if the water contamination was pulled into the steam side. These efforts went on all night with no success.

Many times finding the leak is made more difficult by the temperature changes and loss of pressure after the circulating water is removed and the load reduced, which can cause the leak to close off if it is just a small hole or crack.

Figure 7-17: Ultrasonic Probe

The next morning predictive maintenance department signed on to the clearance and entered the condenser waterbox. The decision was made to utilize ultrasound to attempt to locate leaking tube or crack in the tube sheet. A general purpose probe was used first to scan the entire tube sheet to get a general idea of the leak location. With some experimentation it was decided to tune the probe for 40 khz which seemed to work better in those conditions. Very quickly an area was identified as possibly containing the leak. By further refining the frequency to 36 khz the leak location was narrowed to two suspect tubes. A piece of ½ tubing and some duct tape was then used to fashion a nozzle to attach onto the ultrasonic monitor. This nozzle enabled insertion of the ultrasonic monitor into each individual tube providing further sensitivity and confirmation of the leaking tube. To improve detection sensitivity, a brass plug was inserted into the other end of the suspect tube so that all leakage would be directed to one end. This tube was then identified and marked as a leaking tube, and Maintenance then plugged both ends.

The condenser was closed back up and the Circulating water valved back in to confirm that the leak was repaired. The water chemistry no longer exhibited a condenser leak so the unit generation was increased to maximum capacity. The drum blowdown was closed and the unit continued to exhibit good water quality. One leaking tube was confirmed to be the source of the contamination, and the unit was then released back to the system with no curtailment.

Conclusion: Ultrasonic monitoring was very effective at detecting a small condenser leak.

Case Study 2

NTPC Gas Power Station [12]

"Condenser tube leakage was suspected as conductivity had increased to 0.45 µS/cm against normal value of <0.2 µS/cm. Both halves of condenser was surveyed one by one. Total 44 tubes were identified to be leaking and the same were plugged. After plugging of tubes and charging both halves of condenser conductivity value came down to 0.108 µS/cm and remained stable at same value even at full load. In this event Unit shutdown was avoided. Time taken to survey all condenser tubes of both half of condenser by acoustic equipment was 6-8 Hours."

Parameter	Before Test	Value after tube plugging	Limit
After cation conductivity (µs/cm)	0.45	0.108	<0.2

Case Study 3 [12]

NTPC Coal Power Station

"High cation conductivity in hot well of 500 MW unit was observed and After Cation Conductivity (ACC) value reached 0.55 µS/cm with 2 CPU in service. Tube leakage was suspected and all condenser tubes were checked by acoustic equipment by isolating one half of condenser one by one at partial load. A total of 16 tubes were identified to be leaking and the same were plugged. After charging both halves of the condenser, replacement of resin and stabilization ACC value settled to 0.17 µS/cm (normal value <.2 µS/cm) with one CPU in service. The unit had been running with 2 CPU in service."

Parameter	Before Test	Value after tube plugging	Limit
After cation conductivity (µs/cm)	0.55	0.17 (1 CPU I/S)	<0.2z

NTPC has used the acoustic leak detection method at several stations and has experienced success at each station as shown in Figure 7-18.

Figure 7-18: ACC Before and After Plugging

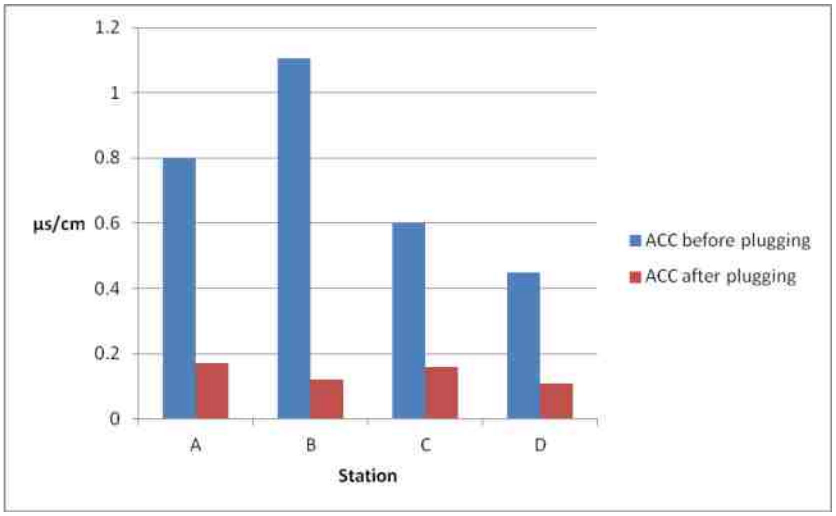


Table 7-9 displays experience of CENPEEP utilizing several methods of checking for tube leaks.

Table 7-9: CENPEEP - Different Methods of Checking Tube Leaks

Methods	Load Condition	Time	Effectiveness
Flame Test/ Soap Bubble Test	Partial Load	12 Hrs	Minor leakage is not detected
Saw Dust Treatment Test	On Line, Full load		Hit & Trial, Temporary relief as well
Flood Test	Off Load/Unit Shutdown	24 Hrs	Proven Method for detection of Leaking tubes
Helium Leak Test	Partial load	24 Hrs	Cumbersome method, all types of leaks detected, Individual tube shot injection is required
Acoustics Portable Equipment	Partial load	4-6 Hrs	All tubes are surveyed by non-contact method, less time, All major/minor leak detected, Unit shutdown avoided.

7.10 TOWER AND CONDENSER CASE STUDY

Case Study I (Contributed by Clean Air Engineering)

A heat rejection cycle analysis was performed for a coal-fired 102 MW thermal plant. This evaluation included a measurement of the circulating water flow rate, a thermal performance test of the cooling tower, and a cleanliness evaluation of the condenser. An analysis was performed using the component performance and the turbine back pressure to determine the effect of the heat rejection cycle component performance on the back pressure of the turbine.

A single counter flow cooling tower serves the cooling needs of the main steam surface condenser. Thermal design and test data for the cooling tower are presented in Table 7-10.

Table 7-10: Cooling Tower Test Summary

Test Parameter	Units	Design	Test
Water flow rate	gpm	57,000	56,873
Hot water temperature	F	101.0	80.0
Cold water temperature	F	81.0	59.8
Wet bulb temperature	F	72.0	36.2
Cooling range	F	20.0	20.5
Fan power	hp	192.4	246.7
Capability	%	100	98
Cold water temperature deviation at design conditions	°F		0.3

The average tested cooling tower capability was 98 percent. The tested capability correlates to a cold water temperature that is 0.3 degrees higher than design cold water temperature when the tower is operated at design conditions of water flow rate, fan motor power, and range.

Condenser performance data are presented in Table 7-11.

Table 7-11: Steam Surface Condenser Data

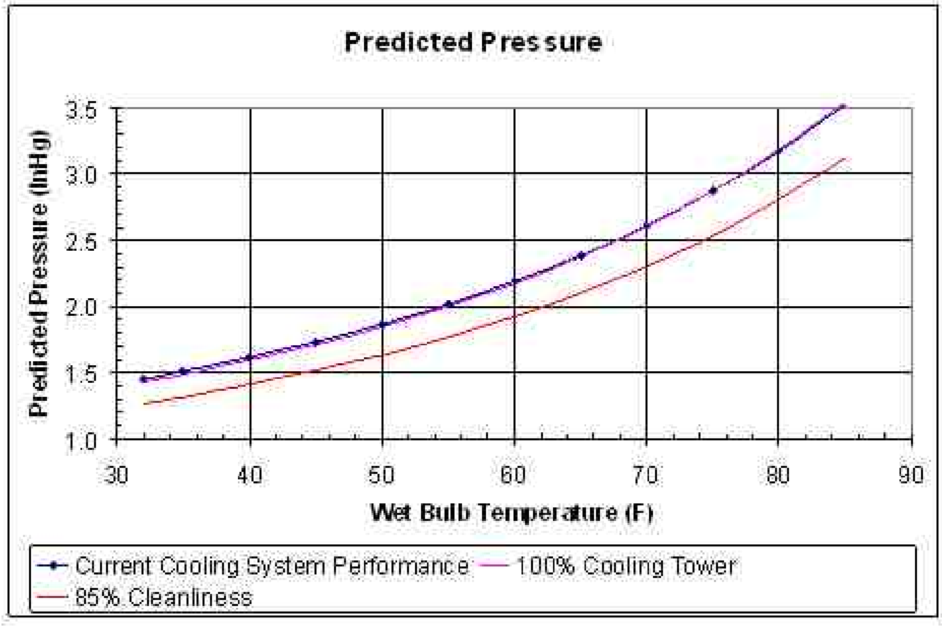
Test Parameter	Units	Design	Test
Heat duty	Btu/hr	4.94×10^8	5.76×10^8
Steam condensed	lbm/hr	522,520	---
Condensing steam pressure	InHg	2.3	1.48
Condensing steam temperature	°F	105.85	91.3
Circulating water flow	gpm	57,000	56,873
Inlet water temperature	°F	91.0	59.5
Outlet water temperature	°F	101.0	80.0
Cleanliness		85%	67%

The condenser cleanliness was determined to be 67 percent. This is significantly lower than the 85 percent cleanliness value required to achieve the design condenser pressure at the design conditions of water flow, heat duty, and inlet water temperature. The effect of the deficiency in condenser performance on the back pressure of the turbine ranges from 0.3" Hg at an inlet water temperature of 55°F, to 0.5" Hg at an inlet water temperature of 85°F. The change in expected heat rate ranges from 8 Btu/KWh at an inlet water temperature of 55°F, to 65 Btu/KWh at an inlet water temperature of 85°F.

The circulating water pumps were performing slightly above their design specification exceeding design flow rate while operating at a higher-than-design total head.

Figure 7-19 illustrates the decrease in condenser pressure which could be achieved by maintaining a condenser cleanliness of 85 percent or by increasing the cooling tower performance to 100 percent.

Figure 7-19: Predicted Back pressure as a Function of Wet Bulb Temperature



As can be seen by from Figure 7-19, the effect of increasing the capability of the cooling tower to 100 percent would be very small. Alternately, depending on the inlet wet bulb temperature, the condenser pressure would be reduced by approximately 0.2-0.4"Hg by increasing the condenser cleanliness to 85 percent.

The condenser cleanliness impact on unit heat rate for this plant is illustrated in Figures 7-20 and 7-21.

Figure 7-20: Predicted Heat Rate vs. Inlet Water Temperature

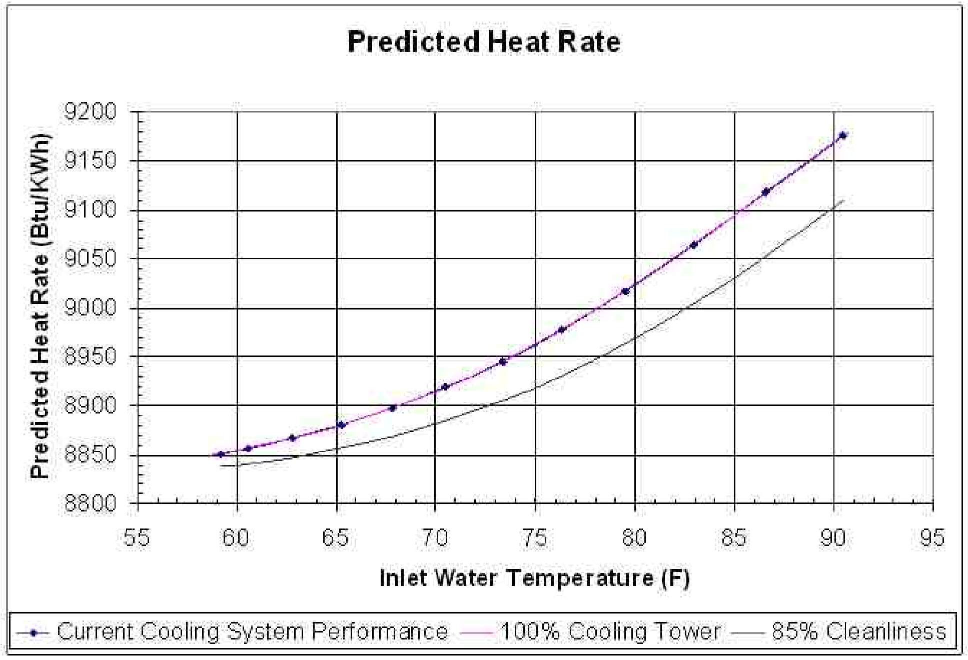
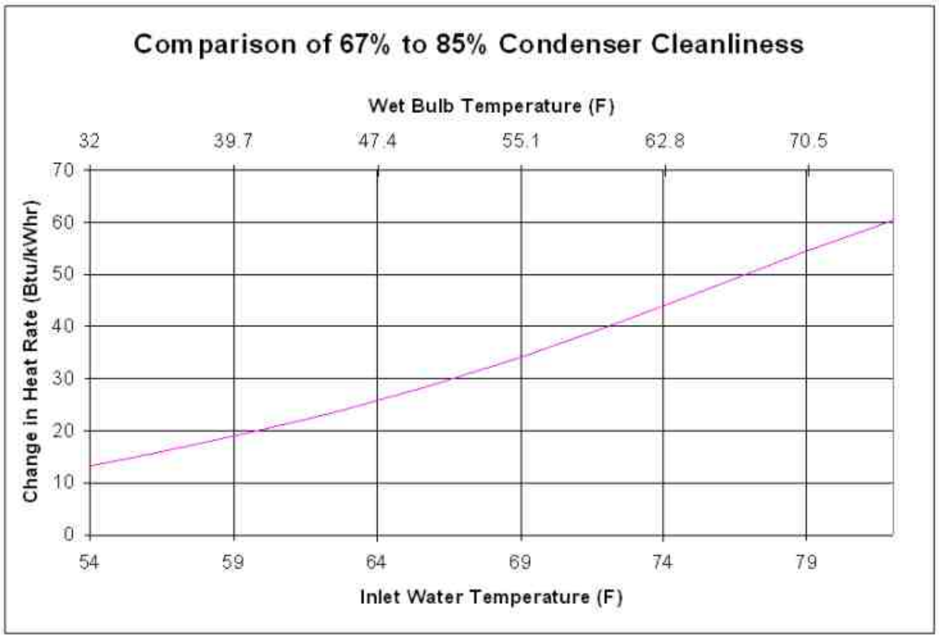


Figure 7-21: Change in Heat Rate vs. Inlet Wet Bulb and Inlet Cold Water Temperature



The heat rejection cycle analysis identified the condenser as that component of the heat rejection cycle which is failing to meet its design specifications. The effect of the deficiency in condenser performance on the back pressure of the turbine ranges from 0.2" Hg at an inlet water temperature of 55°F, to 0.4"Hg at an inlet water temperature of 85°F. The change in expected heat rate ranges from 13 Btu/KWh at an inlet water temperature of 55°F, to 61 Btu/KWh at an inlet water temperature of 85°F. The previous curves presented can be used for economic justification for a program of condenser cleaning and/or an air in-leakage reduction program.

Case Study II (Contributed by Clean Air Engineering)

A heat rejection cycle analysis was performed for a nuclear power plant. This evaluation consisted of a measurement of the circulating water system flow rate by the dye dilution method, a thermal performance test of the natural draft cooling tower, and a cleanliness evaluation of the condenser. An analysis was performed using the system component performance and the turbine back pressure correction curves to determine the effect of the heat rejection cycle component performance on the power production of the unit.

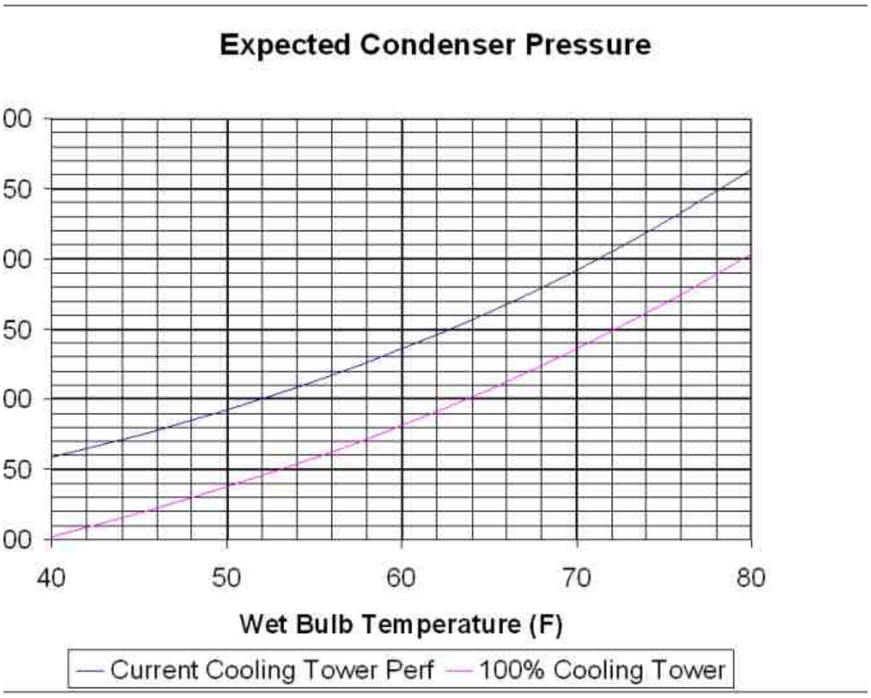
The cooling tower capability was 74 percent of design. The tested capability correlates to a cold water temperature that is 5 degrees higher than design when the tower is operated at design conditions of water flow rate, range, wet bulb temperature, and relative humidity.

The water flow rate as measured by the dye dilution method was 129,855 m3/hr (571,736 gpm) compared to the design value of 125,373 m3/hr (552,000 gpm). Comparison to the pump performance curves indicated that the water flow per pump was slightly higher than that indicated by the pump performance curves.

The condenser cleanliness was determined to be 64 percent. This is a very low value but slightly greater than the value required to achieve the design condenser pressure at the design conditions of water flow, heat duty, and inlet water temperature. The original condenser design used a cleanliness of 70 percent, justified because the plant uses water from a salt marsh for circulating water makeup. The condenser uses titanium tubes. The performance factor as specified by the Heat Exchange Institute (HEI) for titanium tubes was lower when the condenser was designed than that used in the current version of the HEI code (www.heatexchange.org). Using the current HEI standard, the design cleanliness would be 62 percent.

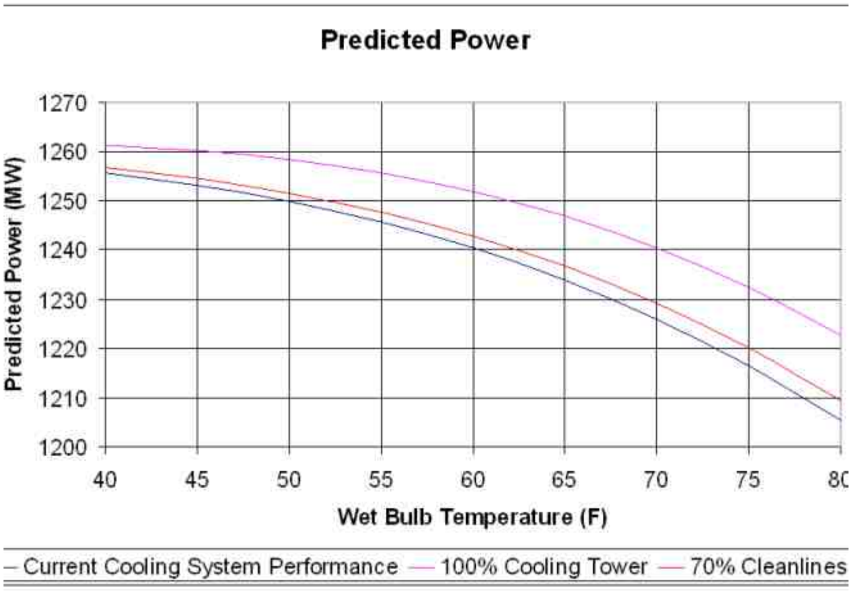
The circulating water pumps and the condenser were performing slightly above their design specification. The average cooling tower capability of 74 percent is indicative of a gross deficiency in the performance of this component. The effect of this deficient performance on the condenser pressure over a range of ambient wet bulb temperatures is illustrated in Figure 7-22.

Figure 7-22: Condenser Pressure vs. Wet Bulb Temperature



The effect on unit power production, calculated using the turbine back pressure curves, is illustrated in Figure 7-23.

Figure 7-23: Expected Power Production as a Function of Wet Bulb Temperature



The heat rejection cycle analysis identified the cooling tower as that component of the heat rejection cycle which is failing to meet its design specifications. The effect of the deficiency in cooling tower performance on the power production of the turbine ranges from 10 MW at a wet bulb temperature of 10°C (40°F), to 18 MW at a wet bulb temperature of 26.7°C (80°F). The curve in Figure 7-23 can be used for economic justification of a rebuild (fill replacement) of the natural draft cooling tower.

Conclusions

Evaluation of the heat rejection cycle provides an important tool to evaluate the economics associated with cycle improvements to improve plant heat rate and capacity while reducing plant emissions. The cycle analysis differentiates the components so that operating and maintenance dollars can be efficiently spent on the components that reduce the plant efficiency and capacity and may potentially cause summertime curtailments. Units with significantly underperforming heat rejection components can see rapid payback intervals associated with improvements in the operating performance of these components.

Work Process Management for Improved Availability

8.0

8.0 Work Process Management for Improved Availability

8.1 SUMMARY

This section attempts to communicate one thing: People affect the business "bottom line" most, not science and technology. Applied technology is important, but not to the same degree as getting people to focus on achieving "Bottom Line" business goals and expectations. This requires management discipline and training, structure, accountability, and human factor "checks and balances" that properly managed work processes provide.

- Section 8.1 provides reinforcement of the point made above by exposing the reader to and defining what constitutes typical "work processes" in the power production industry.
- Section 8.2 introduces process accountability; how success or need for improvement is measured through reliability measures. "Best Practice" process performance measures are introduced, defined and context provided for their proper application.
- Section 8.3, Work Management and Productivity, communicates an understanding of how proper development and application of work processes relates to workforce efficiency and effectiveness. Many "hurdles" that inhibit individuals from being most efficient and effective in both routine and non-routine circumstances are described and "Best Practices" recommended for their elimination. Added attention is paid to addressing non-routine circumstances that exist during unit turn down or outage in Section 8.3, Outage Planning & Management. Continuous improvement is a central focus throughout the entire section.
- In Section 8.4, the central communication to the reader is the relationship between improvements in outage work processes and the corresponding improvement in outage frequency and duration that result.
- Section 8.5, Human Error Reduction, exposes some real-world human factors, e.g. "the wrench" and the "work process works" that inevitably challenges optimization of workforce effectiveness and efficiency. Several "Best Practices" from others who have overcome the same challenges are provided for consideration.
- Another aspect that inhibits workforce effectiveness is detailed in Section 8.6, Root Cause Analysis. A central theme communicated in Section 8.6 is the importance of adapting a "randomly timed" work process, often dissociated from other more-routine day-to-day work processes but equally important to consider. The root-cause analysis system or systems help busy people understand the myriad problems they are exposed

to on a day-to-day basis, the consequences that result, the true root causes of the problems and thorough resolution of all root-causes to keep them from reoccurring.

- Section 8.7, Equipment Condition Monitoring, is about understanding the condition of plant equipment non-intrusively using “hard-wired” continuous and portable periodic sensing of condition indicators to maximize reliability and costs and minimize errors caused by human intervention. Predictive maintenance and condition monitoring has become a cornerstone maintenance strategy, much preferred from a production and cost standpoint over reactive and preventive strategies.
- Case Studies in this chapter form a collection of “Best Practices” considered by the authors to be useful to the reader.
- Section 8.8, Root Cause Failure Analysis, at Southern Company describes a large U.S. utility's programmatic approach to Root-Cause Analysis.
- Section 8.9, MTTI and MTTR Metrics, expounds on reasons why these “leading” metrics are so valuable in measuring the performance of reliability programs.
- Section 8.10, MTBF Metric, expands on Section 8.9 but explains why the “lagging” Mean Time Between Failure (MTBF) metric when implemented and used with MTTI and MTTR can provide simple way to measure reliability program performance.

When an organization is striving for “Best Practice” status by improving the way it does business, there are two types of challenges it must address: technical and managerial. Technical challenges like equipment performance are addressed with technical solutions such as engineering design or modification. Most capital projects are technical solutions.

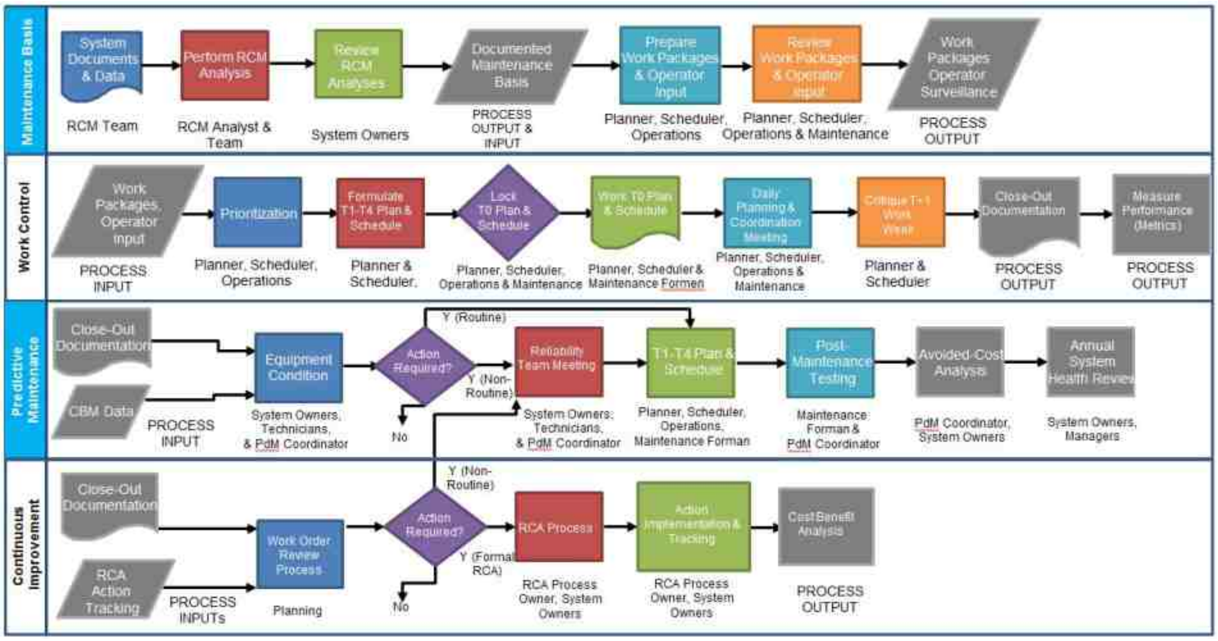
Unfortunately, striving for a best practice is not a technical challenge. It cannot be solved with technical solutions like a new computer system or a predictive maintenance program. Achieving “Best Practice” is a human challenge and must be addressed with a management solution. When the problem is recognized as managerial, then the right tool for the job is a comprehensive, integrated work management process whose design is robust and whose application is consistent (Example in Figure 8-1). Therefore, in an effort to reach best practice levels and sustainable value in your planning and scheduling efforts your entire organization/plant and the associated work culture must be ready to make the necessary changes.

Because the people's involvement is critical to integrating and sustaining the work processes, individuals should be provided with the training and support that makes them most qualified to perform their jobs efficiently. Training and support run the full spectrum; from adequately training technical personnel doing the work, to plant and corporate management support and commitment. In fact, if management support and sponsorship is not in place, then the evolution of an organization from “as found” to some desired state is an exercise in futility and should not continue.

A major part of the organizational evolution is focused on the culture of the organization. The culture needs to be adjusted to the point that plant personnel are prepared and receptive to the changing management philosophies. A work culture that is open and eager for change is the foundation for all other process and technological improvements.

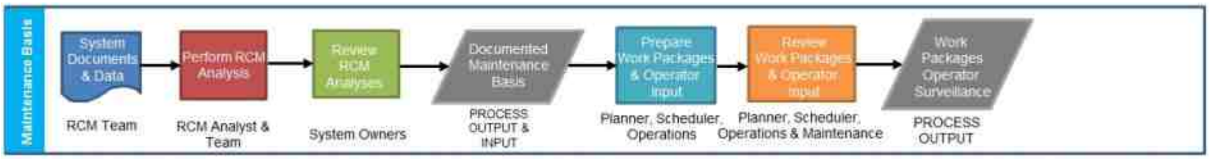
Work culture is as manageable as any other aspect of the business. In essence, addressing your work culture is part of management's responsibility. The work culture is managed by setting the example and by setting expectations and making sure people live up to them, including making and keeping commitments. The commitments are made in a well-defined work management process and are lived up to through a process of accountability. Accountability is the means to keeps process and work culture aligned.

Figure 8-1: Example of an Integrated Plant Work Process



A summary description of each sub-process is provided in Figure 8-2 to familiarize and provide the context for more detailed discussions.

Figure 8-2: Developing the Maintenance Basis and Coupling the Work Management Process



The maintenance basis is established using the Reliability-Centered Maintenance (RCM) methodology. This conceptual methodology identifies the most effective and applicable maintenance tasks for each piece of equipment. This task selection defines the Maintenance Basis (optimum mix of CM, PM, PdM, PAM). A full classical RCM study involves an exhaustive investigation of all failure modes and their effects. This approach, however, has now been streamlined for the utility industry. This streamlined RCM includes the investigation of common, known failure modes and the analysis of the resultant effects, as well as the determination of effective and applicable maintenance tasks to address those modes.

This process shown in Figure 8-3 includes:

* Rank the plant systems and equipment

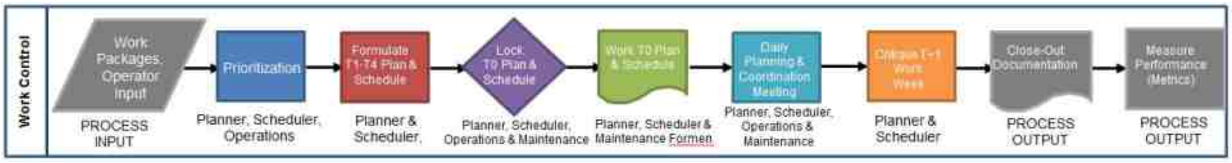
* Determine the failure modes and causes

* Select tasks (CM -run to failure, PM, PdM, PAM) that addresses the failure modes

* Capture the operations and maintenance procedures

* Capture standardized work packages

Figure 8-3: Work Control or Work Management Process



The Work Control or Work Management Process shown in Figure 8-3 covers, planning, prioritization, scheduling, work execution and work close-out. Planning and Scheduling covers:

- Back log management
- Work packages
- Parts availability (Stores/Inventory)
- Parts staging
- Daily schedule
- Multi-week schedule
- Outage schedule
- Tracking planning accuracy
- Tracking schedule compliance

The Work Execution element of Work Process covers the following:

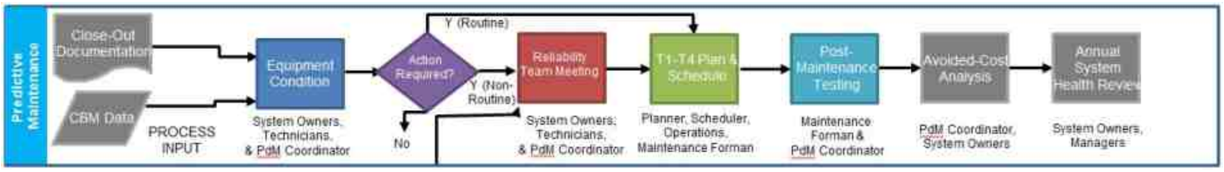
- Man-hour Utilization
- Staff Training
- Tools Availability
- Tool Upgrade to Latest Technology
- Track Rework vs. Total Work
- Track "Wrench" Time vs. Total time

Work Close-out element captures:

- Obtaining detailed maintenance histories
- Addressing post maintenance testing
- Reviewing work orders with the intent of eliminating work in the future
- Feedback to the origination of the work orders

Predictive Maintenance (PdM) is performing maintenance based on the condition of the equipment. The basic periodic condition monitoring technologies are non-destructive examination, visual inspection, vibration, thermography, and oil analysis, acoustic and ultrasonic surveillance, motor testing (winding resistance, capacitance/dissipation factors, insulation resistance, etc.). This is shown in Figure 8-4.

Figure 8-4: Predictive Maintenance Process

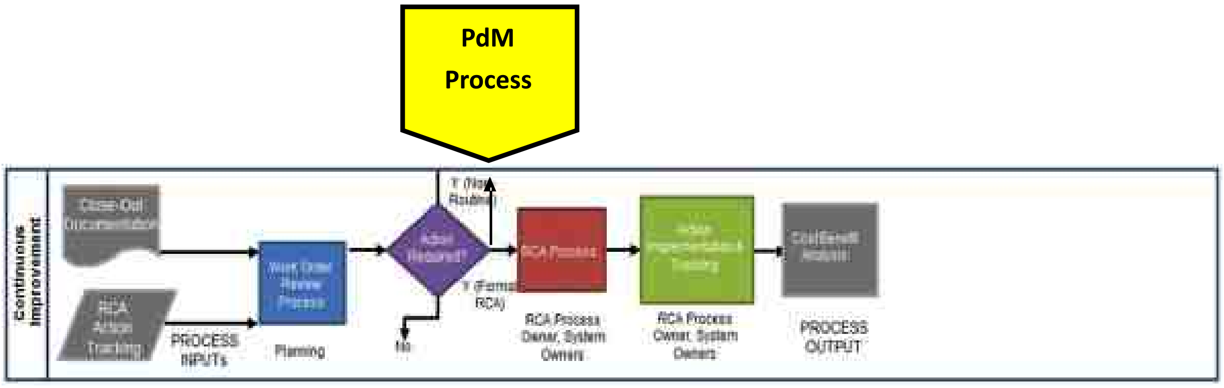


PdM is, however more extensive than just applying technologies for monitoring. To be completely effective, PdM condition monitoring data is collected and combined with other pertinent data related to a particular component. Integrated, with continuous data streams from data historians, and augmented by equipment maintenance history from Computerized Maintenance Management Systems (CMMS) most of the more common failure modes and mechanisms that affect power plant equipment can be detected and/or validated long before damage becomes significant.

Integration of all relevant data for hundreds of components and getting support for the program from all plant departments is complicated. Therefore, most advanced PdM programs are led by a PdM Coordinator. The PdM process includes:

- Determining roles and responsibilities
- Establishing the PdM Work Process and how it fits into the plant work process as seen in Figure 8-5
- Determining the equipment that will be in the program and the condition indicators that will be used to determine the equipment condition
- Establish channels of communication
- Preparing a condition assessment report
- Establishing and measuring the Return on Investment and Cost Benefits
- Establishing and tracking continuous improvement metrics

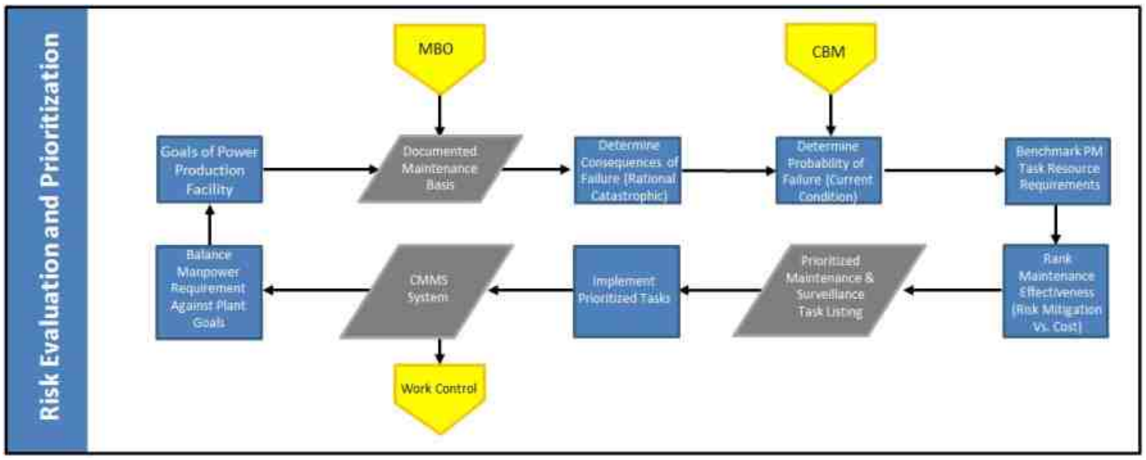
Figure 8-5: Continuous Improvement Process



It is important to establish a continuous improvement process, which has a feedback loop. This process determines what type of work was performed, could it have been avoided and what steps should be taken to eliminate it. This process covers:

- Root cause analysis
- Determine the failure mode and cause
- Modify the maintenance basis
- Review periodically the "good work orders" and modify the basis as needed.
- Track work order types

Figure 8-6: Risk Evaluation and Prioritization Process



The Risk Evaluation and Prioritization (REAP) process shown in Figure 8-6 was developed to have a means to make better business decisions on whether or not to perform outage activities using information on the condition of equipment and on the outage task's financial impact. The same model can be applied to similar decisions for performing routine PM tasks and capital projects to achieve maximum gain from limited funding. REAP results in the assignment of value to the individual tasks. This value derived from performing the task is then plotted against the cost of performing the task. From this, an optimized decision is possible for what tasks to perform that result in the highest worth for the plant.

REAP consists of three activities:

1) High level filtering of all possible outage task activities to assure all regulatory work is included, only outage work is selected and work addresses all of the failure modes that have been experienced. Assumptions are made that all tasks are preventive or condition-based.
2) Placing value on the selected tasks versus the cost to performance of the task.
3) Preparing and presenting the data so that decisions can be made and agreed upon.

8.2 UNIT RELIABILITY MEASURES

Background

The North American Electric Reliability Corporation (NERC)* Generation Availability Data System (GADS) is considered a "Best Practice" source of data for use in measuring, analyzing and/or benchmark comparisons of all power plant types, sizes and configurations. What to measure, why to measure it and how to measure will be explained in this section.

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* Contact NERC at: North American Electric Reliability Corporation, 3353 Peachtree Road, NE, Atlanta, GA USA 30326 or directly at: Phone: 404-446-2560, Internet: http://www.nerc.com,
e-mail: gads@nerc.com. The authors thanks Mike Curley (pc-GAR) and GADS Staff members for their cooperation in producing this section.

Introduction

Generating unit availability is important to electric utilities. Poor performance has many consequences: loading units out of economic order, purchasing power, and installing new capacity, for instance. Utilities created the Generating Availability Data System (GADS) to help them make informed decisions. The Generating Availability Data System (GADS) is a unique series of databases used to collect, record, and retrieve operating information for electric generating equipment. Thirty years of data is used to assist performance research on power plant availability stored in its database. The information is used to support equipment reliability and availability analyses and decision-making by GADS data users. The GADS database includes operating histories for more than 5,000 electric generating units. These units represent a majority of the large generating units in the U.S. and Canada. More than 170 generating companies represent investor-owned, municipal, state, cooperative, provincial, independent power and federal sectors belong to GADS.

Each utility provides reports, detailing its units' operation and performance. The reports include types and causes of outages and de-ratings; unit capacity ratings; energy production; fuel use; design information, and much more. These data are summarized and published annually. Reports are available for downloading. Power Generators/operators who do not report data to GADS will not have access to pc-GAR or any GADS reports. This ruling was established by NERC in November 2000. Contributing power generators have access to detailed data on their units' operation as well as summary information on groups of units. Other power generators and manufacturers can access their own unit-specific data, but not others. Architect-engineers, consultants, regulators, and all other nonutility representatives can have access to summary information for groups of units only.

In addition, GADS Services supports the World Energy Council (WEC) in its analysis of electric power supplies. The WEC Performance of Generating Plant (PGP) Committee is developing a GADS-type program for collecting power plant outage data worldwide. GADS has worked with PGP members over the past years to provide WEC with GADS-type procedures for the uniform collection and reporting of plant outage data. The GADS database was opened to generating companies outside North America in 2004 because there were a number of European, Asian, and South American companies who wanted to report GADS data in GADS format to NERC in exchange for access to manufacturer-specific data, available to GADS members only. For an annual fee, international affiliates can be part of GADS. GADS data are compiled annually and reported in the Generating Availability Report (GAR) and Generating Unit Statistical Brochure. GAR presents data for five individual years and for a five-year average with generating unit availability statistics provided on both a capacity weighted and non-weighted basis.

GADS Services offers pc-GAR software for analyzing power plant performance data. pc-GAR provides users access to millions of event records collected by GADS Services since 1982; it is currently used in twelve countries and is the model used by the WEC PGP Committee. pc-GAR is designed for personal computers, is user-friendly and allows access to the thousands of GADS records from over 8,000 power plants. Analysis to evaluate generator equipment performance on generating units, equipment groups, and major components is possible. pc-GAR can access more than 2,000 cause codes collected from outage records over multi-years. It can analyze hundreds of data combinations using information stored in the unit design, operating data, availability statistics, and fuel characteristics files. Accuracy is assured because data is validated by each reporting utility. pc-GAR design, performance, statistical and fuel files are updated once annually as new sets of information is reported to GADS Services. Using the GADS design data, people can analyze units and major equipment by type, manufacturer and operating statistics.

In 2005, GADS Services introduced a new software product using the GADS data. The software, pc-GAR MT, allows analysis of failure rates and modeling work. The purpose of the software was to calculate the time between failure (TBF) and the time to repair (TTR) based on pc-GAR retrieval criteria, event types and cause codes. The latest, pc-GAR-MT, provides special computer modeling information. The "MT" in pc-GAR MT stands for "mean time". The MT software provides mean-time-between-failure (MTBF) and mean-time-to-repair (MTTR) data for calculating reliability statistics such as Inherent Availability.

The following link can be used to download a complimentary pc-GAR software training video for exploring its features: http://www.nerc.com/pa/RAPA/gads/Pages/pc-GAR.aspx

pc-GAR users can select multiple parameters from the following general categories. These are as follows:

Unit Design/Equipment Configuration Information

Depending on unit type selected, this could vary from dozens of selections. For example, with fossil-steam units, the user can select MW size, number of pulverizers installed/needed for full load, turbine manufacturer, etc.

Unit Performance Measures

Thirty-nine parameters are available for all unit types. These include service hours per year, number of forced outages, unit age, etc. These measures can be used as filters (limit minimum and maximum values) to better benchmark units.

Unit Operating Statistics

There are 13 parameters available for all unit types. These include Equivalent Availability Factor, Equivalent Forced Outage Rate - Demand, Service Factor, etc. Like Unit Performance Measures, Unit Operating Statistics can be used as filters (limit minimum and maximum values) to better benchmark units.

Cause Codes

2,000+ cause codes can be selected for analyzing averages and distributions for improving equipment performance.

Fuel Parameters

Fuel characteristics can be analyzed in pc-GAR.

GLOSSARY AND DEFINITIONS OF TERMS

Operation and Outage States

Actual Unit Starts

Number of times the unit was synchronized.

Age

The number of years the unit(s) has been in commercial service.

Attempted Unit Starts

Number of attempts to synchronize the unit after being shut down. Repeated failures to start for the same cause, without attempting corrective action, are considered a single attempt.

Available

State in which a unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

Forced Derating (D1, D2, D3)

An unplanned component failure (immediate, delayed, and postponed) or other condition that requires the load on the unit be reduced immediately, within six hours, or before the end of the next weekend.

Forced Outage (U1, U2, U3, SF)

An unplanned component failure (immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed from service immediately, within six hours, or before the end of the next weekend.

Maintenance Derating (D4)

The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a capacity reduction before the next planned outage.

Maintenance Outage (MO)
The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, MOs may occur any time during the year, have flexible start dates, and may or may not have predetermined durations.

Maintenance Outage Extension (SE of MO)
The extension of a Maintenance Outage (MO).

Planned Derating (PD)
The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Planned Outage (PO)
The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined start date and duration (e.g., annual overhaul, inspections, testing).

Planned Outage Extension (SE of PO)
The extension of a Planned Outage (PO).

Reserve Shutdown (RS)
A state in which the unit was available for service but not electrically connected to the transmission system for economic reasons.

Scheduled Deratings (D4, PD)
A combination of maintenance and planned deratings.

Scheduled Derating Extension (DE)
The extension of a maintenance or planned derating.

Scheduled Outages (MO, PO)
A combination of maintenance and planned outages.

Scheduled Outage Extension (SE)
The extension of a maintenance or planned outage.

Unavailable
State in which a unit is not capable of operation because of the failure of a component, external restriction, testing, work being performed, or some other adverse condition.

Time

Available Hours (AH)
Sum of all Service Hours (SH), Reserve Shutdown Hours (RSH), Pumping Hours, and Synchronous Condensing Hours,

Or;

Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH), and Maintenance Outage Hours (MOH).

Equivalent Forced Derated Hours (EFDH)*
The product of Forced Derated Hours (FDH) and Size of Reduction, divided by Net Maximum Capacity (NMC).

Equivalent Forced Derated Hours During Reserve Shutdowns (EFDHRS)*
The product of Forced Derated Hours (FDH) (during Reserve Shutdowns (RS) only) and Size of Reduction, divided by Net Maximum Capacity (NMC).

Equivalent Planned Derated Hours (EPDH)*
The product of Planned Derated Hours (PDH) and Size of Reduction, divided by Net Maximum Capacity (NMC).

Equivalent Scheduled Derated Hours (ESDH)*
The product of Scheduled Derated Hours (SDH) and Size of Reduction, divided by Net Maximum Capacity (NMC).

Equivalent Seasonal Derated Hours (ESEDH)*
Net Maximum Capacity (NMC) less Net Dependable Capacity (NDC), multiplied by Available Hours (AH) and divided by Net Maximum Capacity (NMC).

Equivalent Unplanned Derated Hours (EUDH)*
The product of Unplanned Derated Hours (UDH) and Size of Reduction, divided by Net Maximum Capacity (NMC).

* Equivalent hours are computed for each derating and then summed. Size of Reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

Forced Derated Hours (FDH)
Sum of all hours experienced during Forced Deratings (D1, D2, D3).

Forced Outage Hours (FOH)
Sum of all hours experienced during Forced Outages (U1, U2, U3, SF).

Maintenance Derated Hours (MDH)
Sum of all hours experienced during Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Maintenance Outage Hours (MOH)
Sum of all hours experienced during Maintenance Outages (MO) and Maintenance Outage Extensions (SE of MO).

Period Hours (PH)
Number of hours a unit was in the active state. A unit generally enters the active state on its service date.

Planned Derated Hours (PDH)
Sum of all hours experienced during Planned Deratings (PD) and Scheduled Derating Extensions (DE) of any Planned Deratings (PD).

Planned Outage Hours (POH)
Sum of all hours experienced during Planned Outages (PO) and Planned Outage Extensions (SE of PO).

Pumping Hours
The total number of hours a turbine/generator unit was operated as a pump/motor set (for hydro and pumped storage units only).

Reserve Shutdown Hours (RSH)*
Total number of hours the unit was available for service but not electrically connected to the transmission system for economic reasons.

*Some classes of units, such as gas turbines and jet engines, are not required to report Reserve Shutdown (RS) events. If not reported, Reserve Shutdown Hours (RSH) for these units are computed by subtracting the reported Service Hours (SH), Pumping Hours, Synchronous Condensing Hours, and all the outage hours, from the Period Hours (PH).

Scheduled Derated Hours (SDH)
Sum of all hours experienced during Planned Deratings (PD), Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4) and Planned Deratings (PD).

Scheduled Outage Extension Hours (SOEH)
Sum of all hours experienced during Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Scheduled Outage Hours (SOH)
Sum of all hours experienced during Planned Outages (PO), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Service Hours (SH)
Total number of hours a unit was electrically connected to the transmission system.

Synchronous Condensing Hours
Total number of hours a unit was operated in the synchronous condensing mode.

Unavailable Hours (UH)
Sum of all Forced Outage Hours (FOH), Maintenance Outage Hours (MOH), and Planned Outage Hours (POH).

Unplanned Derated Hours (UDH)
Sum of all hours experienced during Forced Deratings (D1, D2, D3), Maintenance Deratings (D4), and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Unplanned Outage Hours (UOH)
Sum of all hours experienced during Forced Outages (U1, U2, U3, and SF), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

Capacity and Energy

Gross Actual Generation (GAG)
Actual number of electrical megawatt hours generated by the unit during the period being considered.

Gross Available Capacity (GAC)
Greatest capacity (MW) at which a unit can operate with a reduction imposed by a derating.

Gross Dependable Capacity (GDC)
GMC modified for seasonal limitations over a specified period of time

Gross Maximum Capacity (GMC)
Maximum capacity (MW) a unit can sustain over a specified period of time when not restricted by seasonal or other deratings.

Net Actual Generation (NAG)
Actual number of electrical megawatt hours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.

Net Availability Capacity (NAC)
GAC less the unit capacity (MW) utilized for that unit's station service or auxiliaries.

Net Dependable Capacity (NDC)
GDC less the unit capacity (MW) utilized for that unit's station service or auxiliaries.

Net Maximum Capacity (NMC)
GMC less the unit capacity (MW) utilized for that unit's station service or auxiliaries.

Non-weighted (traditional) Equations

Age
[Years in commercial service/Number of units]

Availability Factor (AF)
[AH / PH] x 100 %

Average Run Time (RT)
[SH / Actual Unit Starts]

Equivalent Availability Factor (EAF)
[(AH - (EUDH + EPDH + ESEDH)) / PH] x 100 %

Equivalent Forced Outage Rate (EFOR)
[(FOH + EFDH) / (FOH + SH + EFDHRS + Synchronous Hrs + Pumping Hrs)] x 100 %

Equivalent Forced Outage Rate demand (EFORd)
{[(f*FOH) + fp (EFDH)] / [SH + (f*FOH)]}x 100 %

Where:
fp = (SH/AH)
f = [(1/r) + (1/T)] / [(1/r) + (1/T) + (1/D)
r = Average Forced outage deration = (FOH) / (# of FO occurrences)
D = Average demand time = (SH) / (# of unit actual starts)
T = Average reserve shutdown time = (RSH) / (# of unit attempted starts)

Forced Outage Factor (FOF)
[FOH / PH] x 100 %

Forced Outage Rate (FOR)
[FOH / (FOH + SH + Synchronous Hrs + Pumping Hrs)] x 100 %

Gross Capacity Factor (GCF)
[GAG / (PH x GMC)] x 100 %

Gross Output Factor (GOF)
[GAG / (SH x GMC)] x 100 %

Net Capacity Factor (NCF)
[NAG / (PH x NMC)] x 100 %

Net Output Factor (NOF)
[NAG / (SH x NMC)] x 100 %

Scheduled Outage Factor (SOF)
[SOH / PH] x 100 %

Service Factor (SF)
[SH / PH] x 100 %

Starting Reliability (SR)
[Actual Unit Starts / Attempted Unit Starts] x 100 %

Weighted Statistical Equations

Weighted Service Factor (WSF)
[(SH x NMC) / (PH x NMC)] x 100 %

Weighted Availability Factor (WAF)
[(AH x NMC) / (PH x NMC)] x 100 %

Weighted Equivalent Availability Factor (EAF)
{(AH x NMC) - [(EUDH + EPDH + ESEDH) x NMC] / (PH x NMC)}x 100 %

Weighted Forced Outage Rate (WFOR)
{(FOH x NMC) / [(FOH + SH + Synchronous Hrs + Pumping Hrs) x NMC]}x 100 %

Weighted Equivalent Forced Outage Rate (WEFOR)
{[(FOH + EFDH) x NMC] / [(FOH + SH + EFDHRS + Synchronous Hrs + Pumping Hrs) x NMC]}x 100%

Weighted Equivalent Forced Outage Rate demand (WEFORd)
{[S [(FOHd + (EFDHd) x NMC] / S [(SH + FOHd) x NMC]}x 100 %

Where:
fp = (SH/AH)
f = [(1/r) + (1/T)] / [(1/r) + (1/T) + (1/D)
r = Average Forced outage deration = (FOH) / (# of FO occurrences)
D = Average demand time = (SH) / (# of unit actual starts)
T = Average reserve shutdown time = (RSH) / (# of unit attempted starts)

Weighted Scheduled Outage Factor (WSOF)
[(SOH x NMC) / (PH x NMC)] x 100 %

Weighted Forced Outage Factor (WFOF)
[(FOH x NMC) / (PH x NMC)] x 100 %

Average Number of Occurrences Per Unit-Year
AVG NO [(Sum of All Outage and/or Derating OCC PER = Occurrences) /
Number of Unit-Years] UNT-YR

Average MWh Per Unit-Year
AVG MWh [(Sum of All Hours for Each Outage and/or Derating PER = Type x NMC in MW) / Number of Unit-Years] UNIT-YR

Average MWh Per Outage
AVG MWh [(Sum of All Hours for Each Outage and/or Derating PER = Type x NMC in MW) / Number of Occurrences] OUTAGE

Average Hours Per Unit-Year
AVG HRS [(Sum of All Hours for Each Outage and/or Derating PER = Type) / Number of Unit-Years] UNIT-YR

Average Equivalent Hours Per Unit-Year
This is computed the same way as Average Hours Per Unit-Year shown above, except deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each unit. These equivalent hours are then summarized and used in the numerator of the Average Hours Per Unit-Year equation.

Computation Method

Each of the statistics presented is computed from summaries of the basic data terms required in each equation. Examples of these computations are shown below:

EFOR = [(FOH + EFDH) / (FOH + SH + EFDHRS)] x 100 %

Where:
FOH = Sum of All FOHi / Number of Unit-Years
SH = Sum of All Shi / Number of Unit-Years
EFDH = Sum of All EFDHk / Number of Unit-Years
EFDHRS = Sum of All EFDHRSk / Number of Unit-Years

FOF= [FOH / PH] x 100 %

Where:
FOH = Sum of All FOHi / Number of Unit-Years
PH = Sum of All PHi / Number of Unit-Years
NCF = [NAG / (PH x NMC)] x 100 % = Net Energy Produced / Maximum Potential Energy (MPE)

Where:
NAG = Sum of All NAGi / Number of Unit-Years
MPE = Product of Each PHi and NMCi Combination / Number of Unit-Years

NOTE:

I = individual unit in any individual year
k = individual derating occurrence

Major Equipment Group Calculations
EFOR and EAF Examples
EFOR for Total Unit = [(FOH + EFDH) / (SH + FOH + EFDHRS)] x 100 %
EFOR for Steam Turbines = [(All Steam Turbine Related Forced Outages and Equivalent Forced Derating Durations) / (Expected Mission Hours)] x 100 %

Where: Durations are calculated from all cause codes related to the major equipment group.

The Expected Mission Hours = the sum of 1) The Unit-Year Average Service Hours, 2) The FOH due to the major equipment group, and 3) the Equivalent Forced Derated Hours during Reserve Shutdowns when the major equipment group was the cause of the derating.

EAF for Total Unit = [AH - (EUDH + EPDH + ESEDH) / PH] x 100 %

or

{1 - [(FOH+POH w/Ext. + MOH w/Ext. + EPDH + EFDH + ESEDH) / PH]}x 100%

EAF for Steam Turbines = {1 - [(All Steam Turbine Related Planned, Maintenance, and Forced Outages and Equivalent Planned & Maintenance & Forced Derated Hours)/Period Hours]} x 100%

8.3 WORK MANAGEMENT AND PRODUCTIVITY

Introduction

Work management can be defined as "management of workforce efficiency and effectiveness through structured processes". Many power production facilities believe that their work process and management of those processes is optimal. In fact, very few have fully implemented these processes. This accounts for the varying degrees of success that plants have in this area. This section provides descriptions of typical strategies that have been commonly observed that range from near-completely reactive to fully functional work process management systems.

Reactive Planning & Scheduling (An Oxymoron)

In this strategy, virtually no planning or scheduling is done. There is little agreement between Maintenance and Operations as to what work will be done. When corrective work is identified by Operations, it is often requested on an immediate basis. There is little or no faith that work which is placed in the backlog will be done later because more urgent requests are continually being made. Craftspeople are given work orders and sent to the job site without materials or expectations of how long the job should take. Their first stop is at the Control Room where they wait (sometimes more than an hour, at shift change) for the operators to clear the equipment. Then, they must go to the job site to scope the job. When they decide what materials they need, they go to the Warehouse to get the parts from stock. Naturally, the parts required may or may not be there, depending on what is in stock and what must be ordered. Today, levels of inventory are continuously scrutinized. Therefore, it is less likely that a craftsperson can go to the stores window and expect to find all the parts they need to complete a job. Thus, the benefits from decreased inventory can easily be negated by parts expedition charges.

In the event that work can proceed on this job, the crew may get the work partly completed before they are called to another urgent job on another piece of equipment. They must leave the job they are on with the equipment out of service or quickly patch it before they move to the
next job.

Obviously this way of getting work done is frustrating to all involved. Employees get frustrated and moral falls. The result is often lost time, lost productivity, high costs, excess downtime, reduced accountability and unhappy customers.

One Day Look-Ahead Planning and Scheduling

This approach is the one most commonly found in today's generating stations. In it, either planners or 1st Line Supervisors are only looking ahead on the schedule one day. They select the jobs they want to do the next day by looking at the backlog or from requests they have received from Operations. They may make a list of jobs that they want to accomplish, but it is unlikely that this list is agreed upon with Operations or communicated in advance. Certain pre-planned activity may take place, such as preparing protective clearances, but this is not done consistently. They may or may not look into materials requirements. In essence, sites in this state may avoid some of the pitfalls of a completely reactive system, but they are still inconsistent enough that the benefit of their limited planning and scheduling is immeasurable.

One-Week Look-Ahead Planning and Scheduling

Some organizations progress to this next level of planning and scheduling. Some level of planning is done on most jobs. A labor estimate is placed on many work orders and some coordination with internal and external resources takes place. The salient quality of the One-Week Look-Ahead is the weekly schedule. Typically however, this schedule still includes jobs that have not been planned to the point that they are truly ready to carry out, have not been prepared with formal inputs from Operations and/or Engineering and rarely reach further than one week into the future.

Another weakness is that the work is not generally balanced against available resources. Jobs are placed on the schedule without a true understanding of available maintenance labor for the following week. Without this, a "wish list" of items that maintenance would like to accomplish emerges, but not a firm schedule – many times, crews are either under or overscheduled. Regardless, neither Maintenance nor Operations has any real faith that the scheduled jobs will get done. Unfortunately these are the organizations that are the most difficult to change, as they believe they are already planning and scheduling capably.

“Best Practice” Planning and Scheduling

In an organization where the work management process is functioning well, work is identified in a timely manner and issued to the planner with all of the required information on the work request. The planner accesses model work packages – templates that contain safety and advisory information and prepares thoughtful and detailed job plans or work packages that include the remaining elements that could possibly help the craftsperson perform the work quickly with a high level of quality. Job plans include safety guidelines, estimated labor hours, material requirements, task level detail, applicable drawings and any other technical information thought to be helpful.

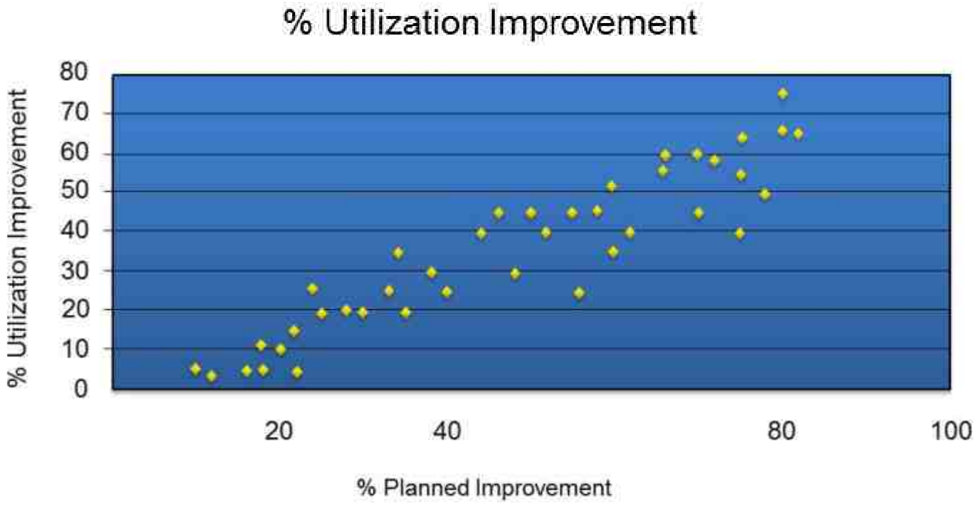
A job is not scheduled until there is confidence among all that it will be ready to be executed when it is supposed to. On weekly and daily schedules, crews and craftspeople are given primary tasks and "fallback" work that they can accomplish if something interrupts the schedule. The work considered most important and scheduled first is preventive and condition-based maintenance.

To summarize:

- Craftspeople are not given work until the job is ready to be done.
- The equipment has been cleared and prepared.
- Materials are available to do the job.
- Activities that involve crews and contractors have been coordinated.
- Unless an emergency occurs, craftspeople should not be pulled off the job – all departments, principally Operations, have agreed to the work through joint prioritization.

Ultimately, more high-quality work gets done in less time with less stress on employees because reasonable efforts to remove obstacles have taken place through the work management process (Figure 8-7). Employees are enabled to perform at the level of performance they have wanted to achieve all along.

Figure 8-7: Improvement in Productivity with Improvement in Work Planning (EPRI, 2001)



The following sections provide in detail, the procedures and activities that are recommended in order to fully implement planning and scheduling.

Performance Measurement and Benchmarking

Managing the work process requires a host of metrics (measures) to represent overall process performance accurately; no single measure will do, and single measures should not be taken out of context in that the information may cause misunderstandings and possibly be used inappropriately. Effectiveness indicators, as with all performance indicator packages, must not simply exist, they must be used. The indicators should be reported frequently with little lag between the time period of interest and reporting. This will help reinforce good results and give early warning of adverse trends. Work Process Management Reports should be widely distributed, discussed and acted upon. In addition, performance indicators should be consistent with industry standards when used for internal or external benchmarking and be useful in supporting decisions to be made. Performance data must be easily measured and collected – in fact generating metrics should be automated to the extent possible so that data collection won't be sacrificed for short-term priorities. Data should have the following characteristics:

- Data collection: easy, automatic, timely
- Data integrity: resists manipulation, objective
- Reporting: fast, frequent, organized for comprehension, graphic
- Communication: distributed widely, posted, discussed formally
- Effectiveness: improving trends

The following metrics are called “leading” metrics. They reflect the performance of the work on a “day to day” basis. They are sensitive indicators that can be used to improve processes before the results show-up too late. Target values for best practices are shown below:

- Schedule Compliance: >90% is “Best Practice”
    - o Sister Metric must always accompany: % Resource Scheduled > 80% for T-1
- PM Compliance: “Best Practice” is 100%
    - o Sister Metric: PM hours: number of hours in the work week spent on PM's as a % of all hours: always >25% is “Best Practice”
- Emergent Work: “Best Practice is <13% of all hours
    - o Sponsored work <12%
    - o Emergency work <1%
    - o % Created by Labor Update 0%

- Resource Utilization
    - "Best Practice" is >68% hours charged to "Wrench turning" Work orders
- Planning Effectiveness "Best Practice" is >80%
- Scheduling Effectiveness "Best Practice" is >90%
- Backlog Management "Best Practice" is <2 months
- MTTR measured per component
- MTBF (MTB CM) WO Coding permits meaningful information
- Process Quality
    - Net Hours Accounted "Best Practice" is 100%
    - WO's closed w/o hours
        - "Best Practice" is PM 0
        - "Best Practice" is CM 0

"Lagging" metrics, on the other hand reflect process performance over time; they typically account for bottom-line results of the process. Examples of lagging metrics are:

- Availability,
- Forced outage rate,
- Capacity factor,
- Total generation,
- Heat rate,
- Emissions,
- Budget - USD/MW or USD/MWh,
- Total manpower,
- Overtime,
- Contractor hours, and
- Hours on blanket WOs.

Responsibilities to the Workweek Schedules and Scheduling Meeting

Operations Superintendent

Preparation

- Reviews the schedule for operability concerns.
- Coordinates all clearances for sponsored and emergency work.
- Provides input to Supervisor Planning and Scheduling concerning maintenance tasks performed by the operations craft.

- Coordinates all clearances for load drops or forced outages are written and approved prior to the event.
- Provides operational start up and shut down sequence schedules and incorporates any testing required during the sequence.
- Ensure Operations Supervisors are aware of any post maintenance tests or performance tests that require rescheduling.
- Writes all clearances required for the respective work week in a timely manner to support having them approved by the end of week T1.
- Works with the Supervisor P&S during weeks 4, 3, and 2 to finalize the details of the workweek schedule. A review of all work activities scheduled for each week is performed to screen work significant to Operations and to ensure proper controls are established.
- Review multi-week schedules with the Planner/Analyst prior to the meeting to ensure an understanding of the content and to anticipate conflicting priorities.

During Meeting

- Attend the meeting per the standard agenda.
- In cases when consensus cannot be reached among participants, assure the final decision with input of the Maintenance Superintendent.
- Accepts the finalized Week T1 schedule and remains responsible for all schedule problems or issues with clearance or testing for that workweek.

Post Meeting

- Ensures all clearances are approved by the end of week T1 and in place the night before the work is scheduled.
- Responsible for daily emergent work and communication with maintenance and Planning and Scheduling for schedule impacts.
- Informs the Supervisor Planning & Scheduling of any sponsored and emergency work that is planned in the week. (This includes a detailed schedule of the plan for the work).
- Provides support to the Planner/Analyst in obtaining cooperation from outside groups or services (operations related items).
- Supports schedule during execution week including Post Maintenance Testing and Performance Testing.
- Verifies all testing is performed as scheduled.
- Follows-up to ensure that action items are accomplished between meetings.

Maintenance Superintendent

Preparation

- Review issues impacting weekly Mechanical, I&C and Electrical schedules with 1st Line supervisors.
- Assure work requiring planning is prioritized and fully planned on a timely basis.
- Examine changing plant priorities and the planned backlog.
- Understand the status of work planned.
- Work with the Planner/Analyst to ensure work is divided appropriately between the mechanical maintenance schedules and that the division coincides with plant priorities.

During Meeting

- Assist in ensuring appropriate coordination between crafts.
- Identify and resolve resource issues (i.e., temporary manpower needs, specialized equipment or outside services).

Post Meeting

- Follow-up on and resolve resource issues identified during the meeting.

Supervisor of Planning and Scheduling

Preparation

- Loads initial schedule (work to be done that week) for the Work Weeks T0 to T4 by incorporating the results of Joint Prioritization and previous Weekly Scheduling Meetings.
- Owns the schedule and makes all changes to the week T4 to week T0 scope.
- Makes necessary logic ties.
- Incorporates all details from First Line Supervisor (including resource allocation).
- Coordinates jobs and safety clearance with Operations and Maintenance Supervisor.
- Develops and maintains planned and unplanned outage work scopes and schedule.
- Chairs regular meetings to discuss and develop the work scope for unplanned outages.
- Serves as Work Scope Coordinator when a forced outage occurs.
- Coordinates the running unit work schedules with the outage unit work schedules.
- Meets with Supervisor - Operations two weeks prior to the workweek to obtain buy-in from the implementing operations crew.
- Coordinates the development of work packages on planned work.

During Meeting

- Chairs the Weekly Scheduling Meeting to integrate work requirements of each unit together with the resources of the plant.
- Facilitates go/no go decisions on maintenance tasks, and facilitates decisions with respect to repair or patch on specific tasks when required.

Post Meeting

- Develops and distributes the schedule so that it can be successfully executed.
- Tracks budget vs. actual.
- Provides Rev 0 schedule to shift management by the afternoon on the Friday preceding the actual workweek.
- Publish schedule during execution week.
- Can chair the Daily Scheduling meeting for emergency work and schedule problems.
- Performs critique of feedback and schedule compliance of the workweek.
- Develops and publishes performance indicators and schedule compliance for each workweek.
- Responsible to manage the work backlog of the plant.
- Follow-up on and resolve resource issues identified during the meeting.

Planner/Analysts

Preparation

- Planner must work with Supervisor Planning & Scheduling to provide input on job plan readiness for scheduling within workweek planning window.
- Job plans will include a description of the work that needs to be done, what sequence, drawings, repair specifications, skills, tools, parts, procedures, estimated man-hours, duration (start to finish), and what safety issues are involved for successful completion of the job.
- All job plans must be complete the end of week T1, and safety clearances in place night prior to execution.
- Planner develops job plans for planned and unplanned outage scopes. Job plans must be prepared before placing on unplanned outage work list.
- Retrieve available labor data from all groups. If labor availability information was provided in a manual fashion from any supervisor, document on appropriate P&S Forms.
- Identify all work orders entering the multi week schedules requiring significant planning and assign planning accountability.

- Examine short-term needs by maintaining contact with the Power Broker to identify the best time to perform load-limiting maintenance.
- Examine changing plant priorities and the planned backlog.
- Prepare tentative multi-week schedules on their P&S Forms for each first line supervisor responsible for maintenance work.
- Communicate tentative multi-week schedules to meeting participants via Local Area Network no later than one full day before the weekly Scheduling meeting.
- Capture all changes to weekly schedules based on participant input, discussion and consensus.

During Meeting

- Provide the status of, or other information related to, critical scheduled jobs being worked.

Post Meeting

- Takes output of Weekly Scheduling Meeting & Daily Scheduling Meeting to develop job plans as required.
- Using the advanced weekly schedules, the planner will prepare job plans on those WO's requiring more significant preparation time.
- Finalize multi-week schedules.
- Coordinate and submit clearance requests for large, multi-craft jobs.
- Communicate to System Operations the scheduled work that will impact load capabilities.

1st Line Supervisors of Groups Performing Maintenance

Preparation

- Determine weekly labor availability and provide this information to the Planner/Analyst.
- For jobs that will be performed over multiple weeks, attribute the amount of time to be worked during the given workweek.
- Update the T0 work week schedule with all emergency and sponsored activities worked on.
- Record on the T0 schedule the actual hours worked on the jobs and job status at the end of the week.
- Determine the status of jobs on the current T0 weekly schedule.

- Identify any potential roll-over of scheduled work.
- Examine changing plant priorities and the planned backlog.
- Identify and notify the Planner/Analyst of PM, project and other critical or aging backlog jobs requiring scheduling.

During Meeting

- Provide the status of, or other information related to, critical scheduled jobs being worked.
- Highlight coordination needs on any jobs involving other crafts.

Post Meeting

- Print and post the multi-week schedules in each designated crew area.
- Gather planned job packages and develop daily schedules.

Plant Supervising Engineer

Preparation

- Determine weekly Engineering labor availability.
- Prepare tentative multi-week schedules for the Engineering department.
- Determine the status of jobs on the current Engineering weekly schedule.
- Examine changing plant priorities and the planned backlog.
- Identify and notify the Planner/Analyst of PM, project and other critical or aging backlog jobs requiring scheduling of any crafts.

During Meeting

- Provide the status of, or other information related to, critical scheduled jobs being worked.
- Capture any changes to Engineering schedules.
- Highlight coordination needs on any jobs involving other crafts.
- Provide input on project work requiring other craft resources (in preparation for outages or to support engineering needs).

Post Meeting

- Distribute the multi-week schedules to all Engineering personnel.
- Communicate and coordinate the finalized schedules with outside engineering groups.

Inventory Warehouse Supervisor

Preparation

- Work with the Planner/Analysts to ensure parts availability prior to scheduling.
- Review tentative multi-week schedules prior to the meeting to understand their content.
- Be aware of dates when parts staging will be required based on the discussion of schedules.

Post Meeting

- Initiate parts staging based on the content of schedules finalized in the meeting.

All Participants

- Prepare any hard copies of the tentative weekly schedules required by you prior to the weekly scheduling meeting.
- Pursue and resolve assigned items on the action item list.
- Provide feedback on individual action items to Planning and Scheduling, as they are resolved during the week and during the meeting.

Standing Agenda for Weekly Scheduling Meeting

- Attendance
- Review progress on previous action items
- Review Metrics
- Discuss power needs for the next three weeks
- Review current T0 week's work
  - Important jobs completed
  - Work that will not be completed
  - Carry-over
  - Re-schedule
  - Overtime
  - Issues and concerns that impacted schedule compliance and work accomplishment
- Review Week T1 schedules
  - Major/Non-routine jobs
  - Coordination requirements
  - Manpower

    - Other crafts
    - Equipment
    - Outside resources
    - Potential problems
    - Achieve consensus and commitment on Week T1 work
- Review Week T2
    - All Work scheduled will be "Ready to Work"
    - Coordination requirements
    - Manpower
    - Other crafts
    - Equipment
    - Outside resources
    - Potential problems
    - Achieve consensus and commitment on Week T2 schedule
- Review Week T4
    - Identify all work entering schedule that is requiring planning and assign accountability.
    - Review and confirm new action items

Standard Planning and Scheduling Form

Purpose

The schedule form is a tool designed to:

- Aid in ensuring documentation of joint prioritization of scheduled maintenance work. This is achieved through:
- Documenting priority jobs for scheduling based on input from Operations, Maintenance, other crafts and the Planner/Analyst as tentative weekly schedules are being developed.
- Documenting total weekly net available man-hours by craft or crew.
- Documenting total weekly scheduled man-hours by craft or crew.
- Documenting percent net available man-hours scheduled by craft or crew for the appropriate week.
- Reporting the above information for review and discussion of schedule content prior to and during weekly scheduling meetings.

- Achieving clarity, consensus and commitment, during weekly scheduling meetings, on the actual jobs that will be contained on finalized weekly schedules.
- Communicate finalized, scheduled maintenance jobs by crew, for upcoming weeks.
- Aid 1st Line supervisors and crews in discussing and understanding the highest priority scheduled maintenance work for the plant for upcoming weeks.
- Provide a tool to track emergency and sponsored work and their accountabilities.
- Provide a tool to assist in communication, cooperation and coordination required between crews.
- Aid in development of daily schedules.
- Provide for the Planning and Scheduling Metrics required for work management.

Responsibilities

- Responsibilities for developing the weekly schedules are defined within the Multi-week Scheduling Process. These responsibilities related to input to, development and review of tentative schedules by appropriate individuals in preparation for and during weekly scheduling meetings.
- The Planner/Analyst will develop and provide tentative and finalized weekly schedules. This procedure defines the appropriate entries on the schedule document.

Frequency

- Finalized weekly schedules for the upcoming multi weeks for all first line supervisors of maintenance activities will be prepared and distributed no less than once each week.

8.4 OUTAGE PLANNING AND MANAGEMENT

"If you fail to plan, you plan to fail" - Ronnie Campbell

This section covers two processes considered to be "Best Practice". The first provides the keys for understanding the concepts of the work process management for outages. This positively impacts both workforce efficiency and effectiveness. The second addresses Risk Evaluation and Prioritization of routine and non-routine (outage) PM tasks. This positively impacts the cost of outages by assuring that tasks with the highest value are performed.

Introduction

The vast majority of plant work is performed by the standing workforce, whose skills are managed through planning and scheduling processes. Work management during planned shutdowns (outages) differ from routine work. Outages, unlike routine maintenance, are rightfully “micro-managed” because so much work must be accomplished within a short period of time. Plants are required to develop an outage plan that is carefully prepared and rehearsed prior to the outage. People often fail to recognize that the planning and scheduling tools and techniques that already exist and are practiced during routine maintenance are similar and vary only to the extent they must be applied.

During outages, plants organize so well that they efficiently accomplish large quantities of work typically impressing others with how much work can be done. Often, this great amount of work can be attributed to the urgency of the situation. However, the success is also due to the organizing effort, primarily the advance allocation of a specific quantity of work to complete. Similarly, planning and scheduling for routine maintenance can help accomplish an equally impressive volume of work. Planning and allocating a week's worth of work to a crew not only creates the same sense of urgency as an “important” outage, but provides tools to manage and improve upon past problems.

Two keys to outage scheduling:

- First, planning provides accurate time estimates for start-up and shut-down of the unit and for larger jobs because larger jobs consist of a multitude of small jobs.
- Second, the scope of the outage must be controlled by managing the identification and inclusion of the small jobs.

An outage is normally considered the taking of an entire unit out of service. An outage is not simply shutting down a redundant process line or piece of equipment. Technicians many times can perform maintenance without taking any equipment out of service. Sometimes, technicians require taking certain equipment or areas of a process out of service for only a brief period in such a manner that allows the unit to continue producing product. For example, operators might briefly take makeup water equipment out of service provided the plant has reserve tanks of water available.

On the other hand, technicians can perform some maintenance tasks without causing the plant to make some or the entire unit unavailable for service. Maintenance may be able to complete some work while the plant runs at a reduced capability. For example, technicians may be able to work on one of two boiler feed pumps while a unit runs at half load. Maintenance situations may require shutting down an entire unit, require no shutdowns at all, or require varying in between unit conditions. Even with a requirement to be off-line, many plants can shut down an entire unit without advance notice or problems - operational or economical. Perhaps the company has not sold out its product line leaving open time. For example, technicians may be able to work on equipment during the day with the unit coming online on a different shift the same day. Plants normally call the taking of an entire unit out of service an outage.

Outages range from “major” outages, scheduled every so many years to overhaul of major pieces of equipment on some pre-defined basis. Major outages are when a plant schedules one or more major process systems for extensive routine replacement, refurbishment, or other maintenance. The work requires shutting down the entire unit because maintenance activities cannot be accomplished when the unit is operating and are often too large in scope to be done during shorter outages whether scheduled or unexpected. Many companies set schedules for these events e.g. once every five years.

They may also have scheduled or unscheduled short outages – usually less than a week long. A short outage is an event between major outages requiring taking the entire unit out of service. Largely because of technological advances and the advent of predictive maintenance programs, systems may be allowed to run longer. Plants can then schedule shorter outages to bring the unit off or just a load de-rating to bring a single system or piece of equipment off when a sophisticated inspection method predicts attention is recommended. The plant strategy may also be to schedule short outages to take a unit out of service to perform maintenance tasks that do not require immediate attention. The plant performs these tasks in anticipation that they will lessen the likelihood having unscheduled or surprise outages at inopportune times.

From the standpoint of reliability, an evolution takes place as a plant increases its reliability through proper maintenance. A plant with good reliability may still have something break and needs a short outage. With proper planning and scheduling, outage work orders are organized into groups by craft and by duration in case the unit comes off for some unforeseen reason. For example, a boiler tube fails periodically requiring shut down for repair. When this occurs and the repair is estimated to take 12 hours, the proper size maintenance group with required crafts springs into action and works all jobs in the outage file with durations estimated at 12 hours or less. Once done, the crews may also be called upon to start longer unscheduled jobs if load dispatch decides that the unit is not needed back in service immediately or if management requests more down time prior to a high-load period because it desire the unit to return in as good a shape as possible. Longer jobs that management decides not to start would wait for a future outage.

However, as maintenance processes improve, reliability also improves and short notice outages begin to become less frequent. The outage work backlog increases initially as reliability improves and the maintenance has fewer opportunities to execute the awaiting outage work. Then as time passes, the plant begins to experience some short notice outages for new, unanticipated reasons. Previously, the maintenance group would have taken care of certain PM tasks at a frequency before becoming too serious by doing the work during short outages. However, when no outages opportunities arise, a pattern emerges; conditions worsen, they bring the unit off-line to address the unanticipated problems. People learn from the experience - prevent reoccurrence and task frequency is adjusted. The evolution continues, the maintenance department's effectiveness improves until there is predictability in when and for how long the unit should be brought down for maintenance.

At this point, management brings the operations and maintenance groups together to schedule short, regular outages for routine maintenance in addition to the standard, infrequent major outages. The entire plant including operations and maintenance must adapt to a strategy of planned short outages to execute short-notice outage work. The plant must accept scheduling an outage in advance when there are a number of serious work orders on the short-notice outage work list or there is a sufficient amount of short-notice outage work. Overall plant reliability and availability increase with the reduction in the occurrence of unplanned short outages, through the strategy of short scheduled outages and less frequent major outages of shorter duration. The evolution continues as maintenance and plant engineering perform defect elimination work to identify and replace equipment that requires excessive routine downtime or work to install plants or systems that incorporate lessons from the past. The evolution results in a superior performing plant capable of full capacity as needed and requiring minimal outages for maintenance.

Planning for Outages

Plants have work orders that they can only execute during an outage. To help the scheduler quickly select the outage jobs, the plant keeps a short-notice outage work list or short-notice outage work grouping of work orders. The short-notice outage work list or grouping identifies and/or keeps the work orders that must be done during an outage together, but not necessarily the next major outage. There are only a few differences between planning work orders for short outages and routine maintenance. Because technicians have limited time during the actual outage to gather parts and information, the company puts more emphasis on planners identifying and staging anticipated parts. The planner has time to do this for even reactive jobs when an outage has not yet started. On the other hand, planners place a high priority on quickly planning outage work orders. They never know when an unexpected outage may suddenly occur that requires finished plans.

Individual work orders may make up some of the work for major outages, but not necessarily all. Large tasks such as certain turbine work may instead involve special outage reports with notes from previous outages. The planners should take advantage of requesting these from the specific supervisors and technicians that worked particular areas during previous major outages to determine estimated times and labor requirements. The outage books could also identify parts and tools from previous outages.

Scheduling for Outages

Many individual work orders for jobs make up outage work. Therefore, the scheduler can utilize the concepts of advance scheduling developed for routine, weekly scheduling. This allows the scheduler to make accurate enough assessments of time frames for the large quantities of work involved in outages. This concept provides the first key to understanding outage scheduling. Because outages consist of many individual jobs, the scheduler can apply the concepts that make weekly work allocations an accurate tool. A scheduler can use planned work order estimates to accurately determine the duration and craft labor hours for major outages. In a routine week of maintenance, a scheduler can allocate the right amount of work even though the time estimates for small jobs have a tremendous amount of variance in accuracy. For example, the planner's estimate for replacing a single control valve may vary considerably. Yet a weekly schedule allocation of 100 jobs smooth out any variation in individual jobs. The work force might therefore have confidence that it could accomplish the overall amount of work in the scheduled week.

The scheduler may similarly consider a single large job that consists of many small work orders and therefore accurately estimate labor requirements for the large job. Thus, the scheduler and planners together can estimate the total duration and labor requirements of overhauling 20 control valves with a degree of precision. A major outage consists of many large jobs and the handling of each large job can be approximated to the weekly scheduling process. Consider the major overhaul of a large steam turbine consisting of many individual tasks on many individual systems. The scheduler and planners together can reasonably estimate the total duration and labor requirements of restoring the turbine itself. The restoration involves many small tasks such as disassembly, inspection, lifting, transporting, machining, coating, polishing, transporting, lifting, assembly, fastening, and alignment. There is also myriad of miscellaneous work orders that the plant identified over the past few years that could only be done during the overhaul. The planners have already planned these work orders. The scheduler can group them to determine their group labor requirements. Overall, the scheduler uses the concept of the grouping of small tasks allowing overall estimate accuracy. Note that during routine maintenance, the crew forecast of labor available for a single week determines how much planned work the scheduler assigns.

For a major outage, the amount of work is the independent variable. That means the amount of work determines the length of the outage considering basically a set amount of labor each week. After determining the initial estimate of the outage duration, management can evaluate options to increase the work force. At this point it is appropriate to mention that all off-line inspections are done as early as can safely be done in the outage. Simple enough, but surprises that threaten increases in outage scope can be better controlled. Management may supplement the regular labor force using agreements to help during major outages. For outage maintenance, the scheduler adjusts the outage time to match a given amount of work, and then considers special labor arrangements. For non-outage, routine maintenance, the scheduler adjusts the amount of work to match a given amount of labor hours. The overall outage can be managed through the Critical Path Method (CPM) and other special scheduling techniques. However, these techniques will all show the large groupings, not the minute, individual maintenance tasks. That is why these techniques can be successfully used with the outage. Because a major outage consists of many individual jobs, the crew supervisor must create daily or shift schedules as the outage proceeds. A scheduler can set the major activities and overall times for the outage, but cannot control individual jobs. At the beginning of each shift, the crew supervisor must ensure persons understand their assignments based on the progress of the previous shift.

The supervisor must provide this coordination during a major outage even though technicians usually stay on the same equipment and are not shifted too much between areas. An entirely different group of technicians may have worked the previous shift. In addition, the technicians may be executing work that the plant performs only once every 5 or 10 years. That means the average technicians may possess only limited experience with the work over their entire employment at the plant. On the other hand, the older crew supervisor may have critical personal experience. The scheduler gathers appropriate short-notice outage work orders and sets the labor requirements and duration for a short, scheduled outage in a similar manner to a major outage. The scheduler and management determine the best crew and time arrangements considering labor availability and shift options.

A single event often drives a short outage. Consider first an unscheduled short outage. Consider again the boiler tube that leaks and causes a unit outage. Maintenance must repair the tube. This single task causes the unit to be on outage and unavailable. For such a task, the responsible crew supervisor and managers must estimate the duration of the outage – perhaps it will take 18 hours. The scheduler then takes all of the work orders that have been in the backlog, waiting for an outage and selects the ones that can be done in 18 hours or less. Maintenance crews then complete as many of the jobs as possible. So, for a short, unscheduled outage, the primary job sets the time frame. Labor availability determines how many jobs the crews can accomplish. The scheduling consists of the scheduler or supervisor taking all the outage backlog jobs with an estimated duration within that time frame and then considers the persons needed to work the jobs. If there are any backlog jobs that have not yet received planning, the supervisor guesses the time requirements and includes suitable ones in the outage scope. The supervisor records all the jobs on a daily schedule sheet with hours for each of the crew members. This is very similar to the regular weekly and daily scheduling routine except for one difference: the amount of hours the crew has for the week does not drive the schedule, the outage backlog selected from the outage file by duration does. The supervisor reassigns persons from the active non-outage tasks and plans the overtime needed to get the work done.

The second key in outage scheduling is that the scope of the outage must be controlled. The scheduler has a specific amount of work; the scheduler can develop specific time schedules and labor requirements. If the company allows the amount of work to vary, the time schedules and labor requirements cannot help but to vary as well. Although the techniques of accurate scheduling are important, the overwhelming key ingredient in making an outage go well is agreement on the scope. The scope itself is less important than agreement on the scope. Many times an outage will start with one scope of work, but as soon as the plant takes the unit off-line, surprises are discovered and the scope doubles.

This is a simple concept to apply to an outage consisting of 100 work orders. The scheduler can reasonably set the labor time requirements from reviewing the job plans. Then the scheduler can establish the overall schedule based upon management preference of the number of crew shifts to work. However, suppose the amount of outage work orders suddenly jumps to 150. The scope of the outage has changed. It has increased by the 50 new work orders. The scheduler must change the schedule.

This consideration is especially important for major outages where the initial part of the outage may consist of inspections of major machinery. If the inspections reveal more serious damage than anticipated, the sudden inclusion of more work may extend the entire outage. This is through no fault of the scheduler. After the inspections determine extra work, the scheduler must then analyze options of labor or critical path changes for management review. This is why outages including major inspections are difficult to schedule precisely. The advent of predictive maintenance technologies has greatly assisted scheduling for major outages. Through sophisticated technology, PdM allows more precise determination of maintenance needs before the plant shuts down major machinery to begin outages. Knowledge of the scope of work however provides only part of this second key to outage scheduling. The rest comes from understanding that the scope must be controlled.

The plant must identify work as far as possible in advance. The plant must not include new work on the eve of or even during the outage whenever possible. Late identification of work will destroy schedules and labor arrangements. Late inclusion of work causes that work to be poorly planned. The ensuing confusion may also cause incomplete execution of new work identified. It might also contribute to hasty decisions being made to delete other work from the schedule. The company may have already used the original schedule to make arrangements for production and sale of product which may become expensive to change. Additional labor necessary to maintain a set schedule with an increased scope may be more expensive or have to be done with less qualified labor than could have otherwise been arranged. Finally, there may be insufficient advance lead time to procure material necessary to execute the work - the maintenance group would not be able to execute that work.

To reduce these problems stemming from scope changes, the scheduler first begins identifying the work to be performed in future outages as far in advance as possible. Many companies have 1-, 5- and 10-year outage plans. These plans identify timeframes for all anticipated outages.

The one year plan might set specific days or weeks, whereas the I0-year plan may set specific weeks or months, whereas the I0-year plan may set specific months or seasons. As the outage time approaches, management allocates time for the schedulers and key company personnel to begin defining the work scope and time frames. The particular scheduling horizons depend on the specific type of outage, equipment lead times, and labor resources. Most of the defined scope for a larger outage is understood 6 months to 1 year before the outage starts. The initial project team makes use of outage files and books. Even work completed every 5 or more years is still repetitious work. A crew executing outage work must record feedback to make historical files most useful. Typically, about 3 months before an outage starts is when scope additions multiply if left unattended. During these months, it seems almost everyone knows about new work requirements but there may not be enough material lead time or other time to prepare adequately for the new work. Therefore, the scheduler must pay close attention to the control of the outage scope.

Schedulers commonly control the scope of outages through the use of lists. The scheduler may issue a list of known work with its main purpose stated 6 months to a year before the start date. At this time, the scheduler may call for an initial meeting with supervisors to identify maintenance needs. Then, with increasing frequency until the start of the outage, the scheduler continues to meet with the supervisors and issue lists of identified work. Special outage planners finish planning the identified work tasks as necessary to have them ready to execute during the outage. An outage project manager ensures this cycle: publish, identify, and plan continues up to the start of the outage. Management support and organizational discipline help ensure that serious attention is given to timely identification of work. Management should make it clear that they do not appreciate late identification of outage tasks. If managers do not wish to have an unexpected outage extension, they must be willing to "freeze" the outage scope and not allow changes or additions at some point before the outage begins. The scheduler might issue a statement at some point before the outage that "Any work identified after this week must be arranged and managed by the originator of the work." Early attention given to identifying the work and the individual sponsoring it greatly reduces the occurrence of late scope additions.

During the course of an outage, the scheduler continues to meet with the crew supervisors to ascertain progress and identify completed work. The scheduler also continues to publish lists of work remaining. The scheduler compares the actual completion of blocks of work against expected completion to measure the progress of the outage. In order to encourage supervisors to attend meetings during the execution of the outage, the scheduler should limit the meetings to 15 or 20 minutes.

After the outage is over, the scheduler should schedule one or two meetings with the crew supervisors, planners, engineers and other personnel, possibly even including technicians. Just as a planner needs feedback to improve future plans, the scheduler and planners seek input and feedback to help improve future outages. The final meetings should address what went right as well as identify where the team could make improvements. These meetings should occur soon after the outages before personnel forget information and ideas.

The plant should manage scheduled short outages similarly to major outages in regard to work scope. The operations and maintenance groups together arrange to have a short outage at a future scheduled time to maintain the plant's capability of operating at full capacity, particularly during high load demand periods. This is NOT recovery from a trip or loss of capacity. The key to how much work and the scope that the maintenance group will accomplish during a short scheduled outage is the plant decision. The scheduler must continually encourage the routine identification of work even if that work can only be done during an outage. This ensures the backlog contains work that is ready to perform. The scheduler also issues the routine preventive maintenance to include. The scheduler reviews any predictive maintenance recommendations or other corrective maintenance in the backlog. With this information, the scheduler prepares a preliminary scope for all of the jobs to be included in the outage for review by the maintenance crew supervisors and plant management. Next, the scheduler takes the scope of work and then assesses how long the outage should last based on discussions with the supervisors on crew availability and management preferences for working a back shift and overtime work. The crew supervisors create a daily scheduling sheet(s) for the outage to get all the work done. As previously discussed, for unscheduled short outages or trips, the primary failure is often the item that determines the length of the outage. The scope normally consists short-notice outage work orders that the planners estimate have a duration of equal length or shorter.

Management must be willing to set a freeze on the scope of even short outages and resist the addition of new work after an unscheduled short outage begins or after setting the scope of a scheduled outage. Otherwise, management must accept the responsibility for outage schedule changes.

A note on involvement of the operations group: timing governs the success of outage work in such a way that one must not forget the time involved for operator tasks. Operators must not only clear equipment, but return equipment to service. Managers and schedulers must include the operations group in all outage meetings to discuss clearance and restoration of equipment to service as well as overall unit start-up requirements. Operators may have a preference for the timing of the return of specific components to manage their activities. Their knowledge may also affect the overall scheduling of the outage. For instance, a major steam plant may sometimes require days or weeks for chemical cleaning prior to return to full capacity. As with any maintenance work, the maintenance technicians are responsible for delivering equipment that is ready to run. However, the operators have the responsibility of testing and returning the equipment to service. Schedulers must include the operators when considering maintenance work.

Two key concepts help the understanding of the scheduling of outages. The first key is realizing that the scheduler can only be accurate when scheduling blocks of work orders. Grouping of many tasks into blocks of work for an outage tends to smooth out the inaccuracies inherent in the estimates of individual tasks. The second key is realizing that the overall ability to schedule outage work accurately lies in the control of additional work to the original outage scope. Schedules or resources must change if the work scope changes. A scheduler can schedule the work scope of an outage. The plant must control the scope.

Risk Evaluation and Prioritization (REAP) Methodology

For Routine and Outage PM Tasks

Introduction

The Task REAP Model has been adapted for application on routine PM and outage PM tasks. The REAP model is intended to create a means to make business decisions on outage activities associated with the boiler from information on the condition of equipment in the boiler and information on the equipment task's financial impact. The model has been successfully applied to streamlining outage work scopes to achieve maximum value with the limited funds associated with today's outage budgets.

The REAP model results in the assignment of value to the individual tasks in the outage. This value derived from performing the task is then plotted against the cost of performing the task. From this plot an optimized decision can be made that identifies the combination of tasks that result in the most value derived for the plant.

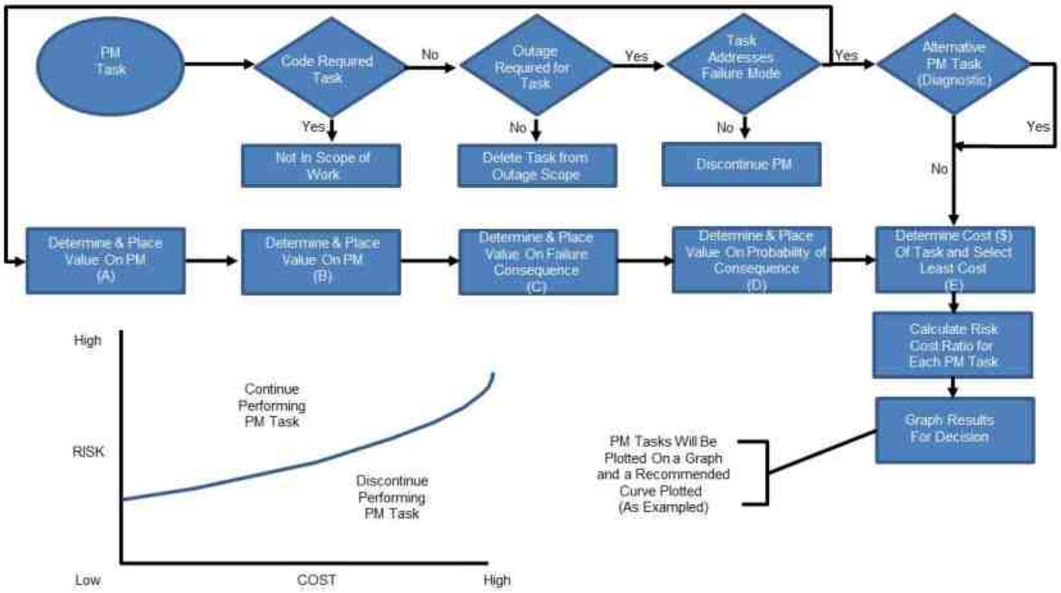
Methodology

The REAP methodology consists of three activities. The first is a high level filtering of all possible outage task activities to assure all code required work is included, all work conceivably performed during non-outage operation are eliminated, and all work tasks address identified occurring failure modes. Figure 1 presents the block diagram of the filtering process used in REAP. The REAP model assumes that the outage task activities are PM (OUTAGE) or CBM tasks. For the purpose of this section both PM and CBM tasks will be called PM (OUTAGE) tasks. Once the PM (OUTAGE) tasks absolutely required and those absolutely not required have been identified, the focus of REAP falls on the balance of proposed PM (OUTAGE) tasks with the other two activities. The second set of activities is to place value on the PM (OUTAGE) and place cost on the performance of the PM (OUTAGE) task. The third activity is to present the data and make the optimum business decision. The discussion contained here is constrained to the second and third activities.

Methodology: Determination of Value on Risk Coverage of the PM (OUTAGE) Task

Placing value on the PM (OUTAGE) task requires establishing value within four value/risk elements. The dominant element is the actual value received by performing the PM (OUTAGE). This value is expressed as "K" in equation 1 on the next page. There are three elements that moderate that value of "K". The first moderator is the factor on cost of the equipment on which the PM (OUTAGE) task is performed. The second moderator is the factor on the value of the component provided to the system to which it belongs. The third moderator is the factor associated with the consequences of failure in not performing the PM (OUTAGE). This third factor is where the condition of the components is taken into consideration. These determined factors establish the value on risk for the PM (OUTAGE) task and is given by the equation:

Figure 8-8: Risk Evaluation and Prioritization Process Model, P&RO Solutions



Eqn 1 Value = K*(PMV+VEP*VCF)

Where: Value = value on risk received by performing the PM (OUTAGE) task

K = value of the PM (OUTAGE) task

PMV = value of the specific equipment (component) on which the PM (OUTAGE) task is performed

VEP = value of the equipment in the system to which the component belongs

VCF = value of the consequences of failure

The factors associated with equation 1 are derived from a series of sub-elements. The factor "K", the value of the PM (OUTAGE) Task, is determined by the following equation:

Eqn 2 K = (A+B+C+D+E+F+G)+1

Where A: Is absolute accuracy required? Yes (1) or No (0)

B: Does PM (OUTAGE) task yield remaining useful life information? Yes (1) or No (0)

C: Does PM (OUTAGE) task yield trendable data?

Yes (1) or No (0)

D: Does PM (OUTAGE) task physically improve the equipment? Yes (1) or No (0)

E: Does PM (OUTAGE) provide as found, as left data?

Yes (1) or No (0)

F: Does PM (OUTAGE) task track a root cause validated failure mechanism? Complete (2), Partial (1), None (0)

G: Is there inherent risk to the equipment in performing the PM (OUTAGE) task? High (0), Low (1), None (2)

The questions provide a rating system when correlated together establish a relative factor for the value of the PM (OUTAGE) task.

The first moderating factor is "PMV", the relative cost of the equipment. The equation for "PMV" is given by:

Eqn 3 PMV = D (A+B+C)

Where A: What is the cost of materials to replace or repair the component?
High (10), Medium (5), Low (1)

B: What is the availability of the component from the supplier?
Unavailable (5), Moderate Availability (3), Available (1)

C: What is the labor requirement to replace or repair the component?
High (10), Medium (5), Low (1)

D: Can the equipment be repaired? Yes (1/2) or No (1)

These questions provide the rating system to assign a relative cost to the equipment being protected. The equation has the form of a dominant factor, the three elements of cost, moderated by whether the equipment can be repaired or replaced.

The second moderating factor is "VEP", the value of the equipment in the system to which the component belongs. This factor is to take into account the relative operating dependency the system has on the equipment. The equation for "VEP" is given by:

Eqn 4 VEP = A+B+C+D

Where A: Is the equipment being protected critical to generation?
Yes (10) or No (1)

B: Will failure cause collateral damage to other equipment?
High (8), Moderate (4), Low (1)

C: Will failure cause a reportable regulatory event? Yes (4) or No (1)

D: Does failure have a personnel safety implication?
High (10), Moderate (5), Low (1)

These questions provide the rating system to assign a relative value to the operation being put into risk if the PM (OUTAGE) task is not performed. The equation summates all extenuating financial implications of the equipment's potential failure.

The third moderating factor is "VCF", the value of the consequence of failure. This factor is to take into account the condition of the component, its maintenance history, and other CBM factors to arrive at a relative evaluation of the probability of failure and the extent of potential damages of that failure. The equation for "VCF" is given by:

Eqn 5 VCF = 0 (A%) + 1 (B%) + 10 (C%) + 100 (D%) + 1000 (E%)

Where

A: What is the probability of satisfactory equipment performance to the next scheduled outage (maintenance history review)? 0% to 100%

B: What is the probability that equipment performance will be degraded?
0% to 100%

C: What is the probability that minor incident (repair and revenue costs) will occur to equipment? 0% to 100%

D: What is the probability that moderate incident (repair and revenue costs) will occur to equipment? 0% to 100%)

E: What is the probability that catastrophic incident (repair and revenue costs) will occur to equipment? 0% to 100%

These questions provide the rating system to assign a relative value on the probability of various dimensions of failure. It is important that the sum of percentages from all five questions total 100 percent. This factor will dramatically increase from one outage to the next outage if the PM is not performed. Obviously the probability of failure would increase upon the decision not to perform a PM from the previous outage. The equation summates all extenuating probable failure implications.

Methodology: Determination of Relative Cost of Performing PM (OUTAGE) Task

The REAP model requires the calculation of the relative value of the PM task as it relates to the task's value to the equipment and the equipment's value to the operating systems. This is described from the equations above. The REAP model also requires the calculation of the relative cost of performing the PM (OUTAGE) task.

The equation for the Cost of performing the PM (OUTAGE) task, "CPM" is given by:

Eqn 6 CPM = C*(F*A)*B

Where: CPM = cost of performing the PM task

C = labor rate

F = correction factor between estimated labor hours and actual

A = labor hours estimate

B = support factor to conduct PM (OUTAGE) (e.g. scaffolding)

There are a series of questions used to determine CPM:

A: What estimated labor hours are required?

B: What support (Material, Scaffolding etc.) is required?
High (3), Low (2), None (1)

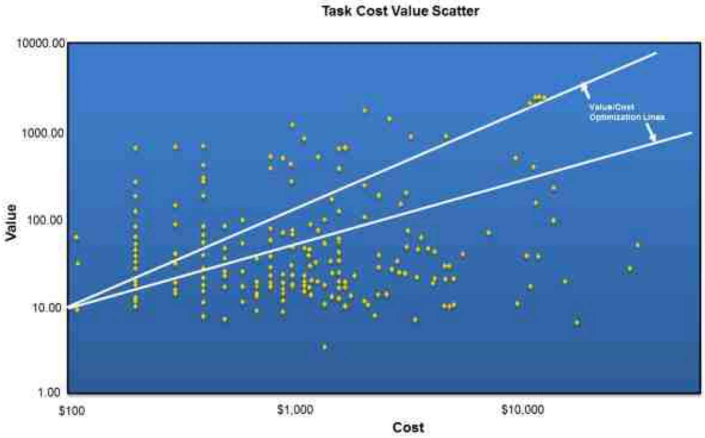
C: What is the labor rate expressed in dollars?

F: What is the labor hours adjustment factor between estimate and actual (if any)?

Analysis Process

The REAP model was applied to 315 tasks associated with a planned outage. The intent was to streamline the outage to be within the limits provided by the outage budget a reduction of 10 percent of the outage estimates for the work anticipated. Each outage task was evaluated for its value to the plant and its cost of performance. Then each PM (OUTAGE) task was plotted value versus cost as shown in Figure 8-9.

Figure 8-9: Value vs. Cost of Project Management



Recognizing that building an outage entails selecting the highest value lower cost items first. Figure 8-10 presents the method used to prioritize each task. Each angle step separates those tasks above the line which are the higher value, lower costs tasks from those below the line which are the higher cost, lower value tasks. As the angle steps move from step 1 through step 19, a method is possible to determine an optimum set of outage tasks at the optimum cost.

Figure 8-10: Angle Steps Method

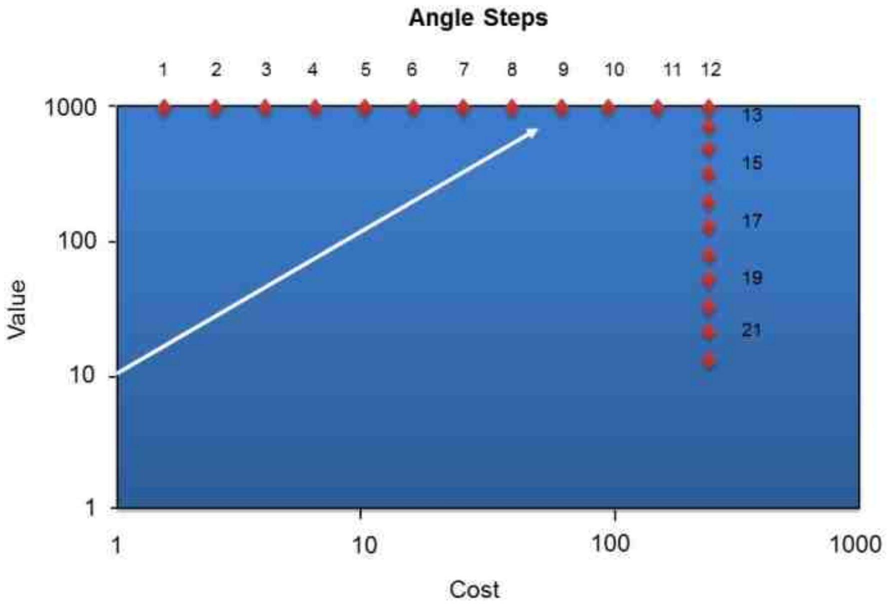


Figure 8-11 presents the results of moving the angle steps through the data of figure 1. Each angle step builds on the tasks from the previous step. The shape of the value – cost curve shows that value builds quickly with limited outage funding until a point is reached where achieving further increases in outage value requires substantially more funding. It is clear that by setting priorities to the tasks of the outage that a majority of the value contained in all the tasks can be funded by a small portion of the outage costs.

Figure 8-11: Value vs. Cost for Numbers of Outage Tasks

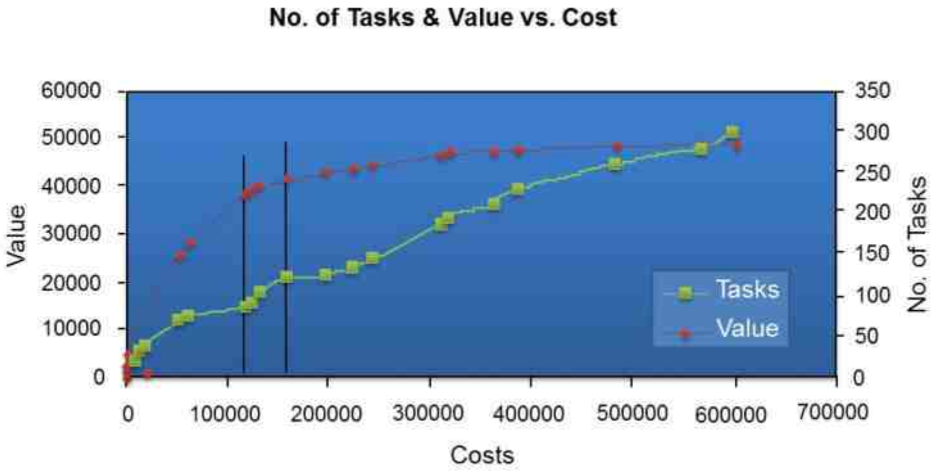


Figure 8-11 resulted in the recommendation that only 87 of the 315 outages (27 percent) be performed (228 tasks not performed). The reason for this was that those 87 tasks captured task value of 38,430 out of the total value of all tasks of 48,856 (78 percent) e.g. 78 percent of the value of the outage is captured by 27 percent of the tasks. This is very reasonable in light of Paredo's 80:20 rule. In terms of cost of performing those tasks, the results were even more in line with Paredo's rule. Of the tasks included in the analysis from the outage plan, a total cost of USD 599,520 would have included everything being accomplished. The 87 tasks only cost USD 119,420 to accomplish or 20 percent of the cost for all considered tasks – a realized savings of USD 480,100.

The REAP model provides a method to engage condition based information into an asset managing process moving from time based activity to risk informed tasks associated with business based decision making. The method is intended to focus on discretionary outage tasks however the method can be applied to a wider audience of outage tasks dependent on how risk adverse the organization is in making business decisions. The REAP model also provides for documentation in business decision making when deciding which outage tasks will be done and which ones will not. Finally it must be understood that the tasks not performed are deferred to be analyzed at subsequent outages when probability of failure factors will increase.

8.5 HUMAN ERROR REDUCTION

Introduction

Human Error Reduction is a critical concept in operating power plants. It can be considered a subset of Human Factors Engineering or Human Factors Analysis. Human errors are responsible for many of the failures in power plants and much of the equipment damage that can have catastrophic impacts on an individual plant, a company or the industry.

Human Error Reduction is a process that can be applied to minimize and hopefully essentially eradicate such errors. The concept has been slow in being implemented in the fossil plant environment in the U.S. and elsewhere. Generally human error reduction programs were first implemented in the nuclear power plant area as well as in other critical industries where errors can have major negative consequences. Two other industries, as examples, are the airline and medical fields.

The term “necessity is the mother of invention” may apply here.

In U.S. utilities where both nuclear and fossil plants exist, the fossil plants saw the benefits in the nuclear plants and then went on to adopt similar human error processes and programs. The fossil plants are much less regulated and therefore have less of an imperative for taking on more programs and processes. The Human Error Reduction process has been one where the value has been recognized and thus readily implemented in fossil plants. The key to effective implementation in fossil plants is to maximize the effectiveness while minimizing the bureaucratic requirements. For a process, and related programs, to be effective, employees must appreciate the value and see that it enhances the overall results obtained both personally and collectively.

Best Practice: Recognize the basic three types of errors

These are rule based, skill based, and knowledge based. The response to different types of errors has to be different. If an employee violates a rule then the consequences will be much different than if there is a knowledge based error due to lack of training. The employee is responsible in the first case and must accept the consequences of his actions. In the second case management is responsible since it is a management responsibility to assure a properly trained work force.

The following is an explanation of the three types:

- The terms skill, rule and knowledge refer to the degree of conscious control exercised by the individual over his or her activities.
- In the knowledge based mode, the operator carries out a task in an almost completely conscious manner.
- The skill based mode refers to the smooth execution of highly practiced actions where there is virtually no conscious monitoring.
- The third category is the use of rules. These rules may have been learned as a result of interacting with the plant, through formal training, or by working with experienced operators. Rules are many times posted and certainly embedded in training and orientation.

Whenever there is an error there should be an analysis of the error for the determination of the type.

Best Practice: Recognize the causes of Human Errors

There are a lot of different things that cause human errors. Some of the more common ones are:

Slip/Lapse:

1. Work environment, housekeeping, distractions, haste or time pressure
2. Repetitive non-stimulating tasks, not taking appropriate breaks, fatigue
3. Person/plant interfaces, controls, displays
4. Difficult environment, inadequate safeguards, noisy environment
5. Error (unforgiving controls)

Mistake:

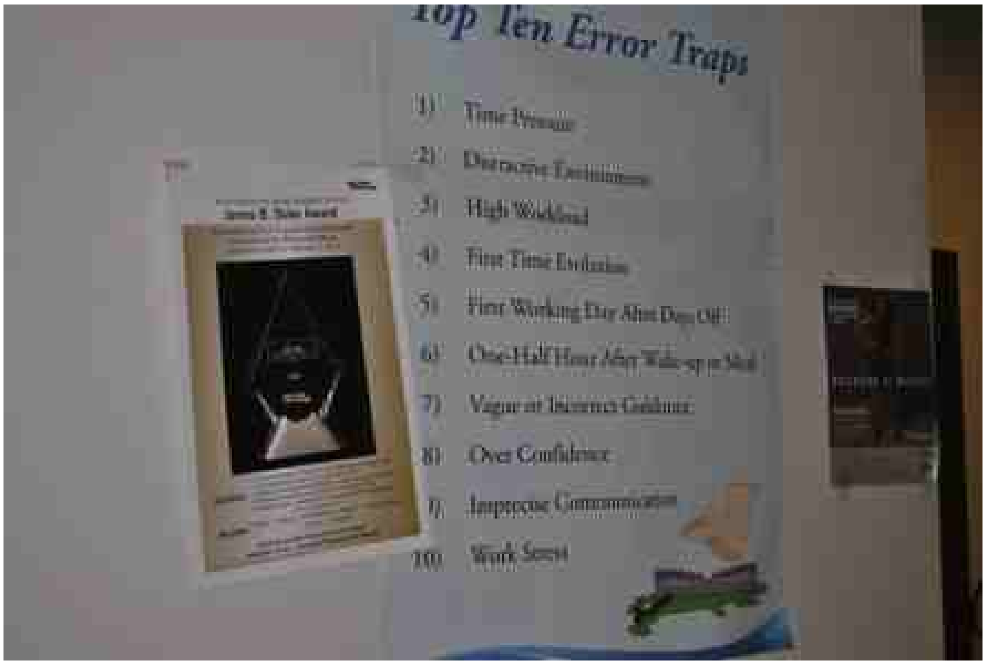
6. Inadequate procedures
7. Training

8. Supervision
9. Support – Management/Peer
10. Hazard awareness
11. Situation awareness
12. Poor/unclear communications

Violation:

13. Procedures
14. Underestimation of true risk
15. Peer pressure (real or perceived)
16. Management pressure (real or perceived)
17. Cutting corners
18. Desire to take risks
19. Lack of positive rewards
20. Lack of involvement
21. Ineffective supervision
22. Unreliable corrections
23. Poor management

Figure 8-12 "Top Ten" Error Traps



At one power plant in the U.S. the following "Top Ten Error Traps" sign is posted in several locations:

It is most important to raise the awareness of the potential for human errors and their causes.

Best Practice: Recognize that shift handover is a time of more Human Errors

Shift change or handover is a time when more human errors occur. Specific actions should be taken to assure the risk is minimized. One such action taken in the U.S. is the reduction of shift handovers by going to a 12hr shift schedule that operators have found more desirable in many additional ways. This eliminates one shift handover per day. In addition the 12hr shift has improved sleep cycles and also greatly improved morale.

Best Practice: Implement a robust Root Cause Analysis Process

Identifying the true cause of errors is essential to error reduction. Left alone without this process many times the "apparent cause" is all that is identified. Much finger pointing can occur and then causes are simply left to fade away. Root cause analysis is essential to preventing reoccurrence.

An example used many times to illustrate the need for root cause is the following ditty:

For want of a nail, the shoe was lost,
For want of the shoe, the horse was lost,
For want of the horse, the soldier was lost,
For want of the soldier, the battle was lost,
For want of the battle, the war was lost,
For want of the war, the country was lost!

Then the question is asked, "What is the root cause?"

This one is pretty obvious to everyone however real power plant examples are much more difficult. To add to the difficulty, many times many separate agendas exist. A persistent questioning attitude is necessary to really get to the root cause. Many root cause processes exist and can be utilized.

Best Practice: Utilize "repeat back" for all critical operating interactions.

For all directions given in the work environment "repeat back" is a good tool to assure clear communications. This can be established as a procedure and utilized in all areas of a station. This is simply the hearer restating what he heard from the speaker and then the speaker acknowledging that the understanding is correct.

Best Practice: Management presence that creates the desire to do the right thing.

Have in place in the power plant a leadership team that is sincere and conveys to the work force that they are the most important asset and that they are truly valued. When a workforce truly believes that the leadership of the organization is sincere, values the work that is being done and values the employees, the team will go to great lengths to not let the organization down. They will be more alert, more conscientious and less prone to human errors. This is the only tool (if it can be called that) that can be embedded in the team and deliver many other great dividends.

Best Practice: Assure Proper Site Specific Training.

It is difficult to put training together on a plant that is very specific to that plant. It is relatively easy to train on how a pulverizer works and describe the different types of pulverizer. This information exists in various sources of documentation and textbooks. It is relatively easy to find instructors for general information like this. It is much more difficult to invest the time and effort to understand the site specific details of the pulverizers and the system within which they operate in a specific plant and then develop training packages on that specific plant. Companies in the U.S. can do this for specific plants. It is essential for reducing errors that such training takes place before initial startup of a plant and periodically throughout the life of the plant. In some ways simulators have taken away some of the urgency for doing this. There has been a belief that only simulator training is adequate. Simulator training is a wonderful tool that has become the standard for modern plants. However, simulators alone are not enough. Operators must learn the "whys" as well as the "hows" of power plant operation. The classroom environment offers this opportunity. Therefore either contract or create "in house" site specific training on ALL systems.

8.6 ROOT CAUSE ANALYSIS

Definitions

Root-Cause

The Root-Cause is the most fundamental breakdown or failure of a process or component which, when resolved, prevents a recurrence of the problem.

Or, simplified,

Root-Cause is the factor or factors that, when fixed; the problem goes away and does not come back.

Root Cause Analysis is a logical process and is a key element of any optimized and sustained process. Root-cause analysis is a consistently-applied, systematic approach to get to the true root causes of the problems.

Or, simplified,

Root Cause Analysis is asking why the problem occurred, and then continuing to ask why that happened until we reach the fundamental process or component element that failed.

Root-cause analysis, therefore, enables determination of root-cause(s).

Background

Overview of Popular Root-Cause Analysis Methodologies

EPRI introduced a comparison of root-cause analysis methods in the Proactive Maintenance Guideline, 2001 (Table 8-1). The comparison was based upon input from the membership and the research that had been done up to that time in the Maintenance Program.

Table 8-1: Analysis Method – EPRI Proactive Maintenance Guideline 2001

Type of Problem	Change Analysis	Barrier Analysis	Event and Causal Factors Charting	Logic Tree Analysis
Organizational	Good	Best		
Activity or Process	Good	Best	Good	Better
New or Changed Activity	Best	Better		Good
Personnel	Good	Best	Better	
Accident or Incident	Good	Better	Best	Better
Equipment Failure	Good		Better	Best

- Conversely, Dean L. Gano, who designed and developed one of the more popular root-cause analysis methodologies, provided with what he considers an un-biased description and commentary of the more popular analysis methods utilized in 2013.

- More detail can be found at http://www.realitycharting.com/ and http://www.brighthubpm.com/methods-strategies/65317-fishbone-vs-apollo-root-cause-analysis/

Gano, studied a variety of root cause analysis tools and methodologies and identified what he considered to be weaknesses in all of them. According to Gano, people often do not achieve real success with root cause analysis because they stop too soon (before reaching the real root cause), focus on placing blame, or fall victim to what he calls "the root cause myth."

He claimed it is a fallacy to believe that there is one root cause for a given problem, and stresses that identification of a single root cause can only be accomplished in conjunction with selecting the type of solution for the problem. For example, the cause of a fire typically has several components, and depending on the situation only one of those may be identified as a root cause that must be or can be addressed.

Gano also felt that trying to categorize potential root causes is unhelpful, and can actually hinder project teams in their efforts to uncover true root causes and viable solutions. So his method of root-cause analysis does not have a categorization component as does the fish bone method. Instead, Gano's analysis method focuses on identifying both conditions and actions that can lead to the problem outcome, and documenting evidence to confirm or deny each of them. This methodology takes into account the fact that a condition alone typically does not represent a cause, without the corresponding action that result from that condition and leads to the problem. Similarly, the action alone does not cause the problem unless the condition is also present. Ideally, improvement efforts should focus on eliminating the condition so that the related action never becomes a factor.

Gano's RCFA Comparison Criteria

In Gano's opinion, a standard of comparison is needed to properly evaluate the many so-called root cause analysis methods and tools. It is generally agreed that the purpose of root cause analysis is to find effective solutions that prevent recurrence of the defined problem. Accordingly, an effective root cause analysis process should provide a clear understanding of exactly how proposed solutions meet their goal. He believes that an effective problem-solving process should meet the following six criteria.

1. Clearly define the problem and its significance to the problem owners.
2. Clearly delineate the known causal relationships that combined to cause the problem.
3. Clearly establish causal relationships between the root cause(s) and the defined problem.
4. Clearly present the evidence used to support the existence of identified causes.
5. Clearly explain how the solutions will prevent recurrence of the defined problem.
6. Clearly document criteria 1 through 5 so others can easily understand the logic of the analysis.

Fault Tree Analysis

Fault Tree Analysis (FTA) is a quantitative causal diagram used to identify possible failures in a system. It is a common engineering tool used in the design stages of a project and works well to identify possible causal relationships. It requires the use of specific data regarding known failure rates of components. Causal relationships can be identified with "and," "or" or various combinations thereof. FTA does not function well as a root cause analysis method, but is often used to support an RCA.

Barrier Analysis

This incident analysis method identifies barriers used to protect a target from harm and analyzes the event to see if the barrier held, failed, or was compromised in some way by tracing the path to the threat from the harmful action to the target. A simple example is a knife in a sheath. The knife is the threat, the sheath is the barrier, and the target is a human. If the sheath somehow fails and a human is injured, the barrier analysis would seek to find out why the barrier failed. The cause of this failure is then identified as the root cause. Barrier analysis can provide an excellent tool for determining where to start your root cause analysis, but it is not a method for finding effective solutions because it does not identify why a barrier failed or was missing. This is beyond the scope of the barrier analysis. To determine root causes, the findings of the barrier analysis must be fed into a principle based method to discover why the barrier failed.

Logic Tree Analysis

This type of root cause analysis is very common and goes by many names such as Ishikawa Fishbone Diagram, Management Oversight and Risk Tree (MORT) Analysis, Human Performance Evaluation Systems (HPES), and many other commercial brands. These methods use a predefined list of causal factors arranged like a fault tree. Ishikawa uses manpower, methods, machinery and environment as the top-level categories. Each of these categories has sub-categories. For example, within the category of manpower, we may find management systems; within management systems we may find training; and within training we may find training less than adequate; and so on. All categorization methods use the same basic logic with the premise that every problem has causes that lie within a predefined set of categories. These methods ask you to focus on one of the categories such as people and, in reviewing what you know of your event, to choose some causal factors from the list provided.

Cause and Effect Charting and Analysis

This is a simple causal process whereby one asks why of a predefined problem, answers with at least two causes in the form of an action and condition, then asks why of each answer and continues asking why of each stated cause until there are no more answers. At that time, a search for the unknown is launched and the process is repeated several times until a complete cause-and-effect chart is created, showing all the known causes and their interrelationships. Every cause on the chart has evidence to support its existence or a "?" is used to reflect an unknown and thus a risk. All causes are then examined to find a way to change them with a solution that is within control, prevents recurrence, meets goals and objectives, and does not cause other problems. The result is clear causal connections between solutions and the defined problem. Because all stakeholders can insert their causal relationships into the cause and effect chart, buy-in of the solutions is more easily attained.

Change Analysis

This is a process that describes the event or problem, then describes the same situation without the problem, compares the two situations, documents all the differences, analyzes the differences, and identifies the consequences of the differences. The results of the change analysis identifies the cause of the change and will frequently be tied to the passage of time and, therefore, easily fits into an events and causal factors chart, showing when and what existed before, during, and after the change. Change analysis is nearly always used in conjunction with another RCA method to provide a specific cause, not necessarily a root cause. Change Analysis is a very good tool to help determine specific causes or causal elements, but it does not provide a clear understanding of the causal relationships of a given event. Unfortunately, many people who use this method simply ask why the change occurred and fail to complete a comprehensive analysis.

Events and Causal Factor Charting

This process first identifies a sequence of events and aligns the events with the conditions that caused them. These events and respective conditions are aligned along a time line. Events and conditions that have evidence are shown in a solid line but evidence is not listed; all other observations are shown in dashed lines. After this representation of the problem is complete, an assessment is made by "walking" the chart and asking if the problem would be different if the events or conditions were changed. This leads to identifying causal factors such as training not adequate, management less than adequate, or barrier failed, which are identified by evaluating a tree diagram. Events and Causal Factor Charting can provide the time line to help discover the action causes, but can allow a degree storytelling with conditional causes. Instead of identifying the many causal relationships of a given event, events and causal factor charting resorts to categorizing the important causes as causal factors, which are then evaluated as solution candidates using the same method as the categorization schemes. Events and Causal Factor charting does not follow the principles of cause and effect.

Failure Modes and Effect Analysis

Failure modes and effects analysis (FMEA), similar to fault tree analysis, is primarily used in the design of engineered systems rather than root cause analysis. Like the name implies, it identifies a component, subjectively lists all the possible failure modes, mechanisms and causes that could happen, and then makes an assessment of the consequences of each failure. A relative score may be given to how critical the failure mode is to the operability of the system or component.

Storytelling

This is not a root cause analysis method but is often accepted as one. It is the single most common incident investigation method and is used by nearly every entity. It typically uses predefined forms that include: problem definition, a description of the event, which made a mistake, and what is going to be done to prevent recurrence. There is often a short list of root causes to choose from so a Pareto chart can be created to show where most problems originate.

"Best Practice" Root-Cause Analysis Methods

Authors Note: Best Practice in Root Cause Analysis reflects opinion formed by working over thirty-five years in and around power plants; power plant equipment and organizations. These opinions are just that and do not reflect any industry standard or others professional opinions.

"Best Practice" Method for Informal Root-Cause Analysis and Root-Cause Screening

Five-Why Method

One of the many brainstorming methods also known as "the Five Whys method" is the most simplistic root cause analysis process and involves repeatedly asking why at least five times or until you can no longer answer the question. Five is an arbitrary figure. The theory is that after asking why five times you will probably arrive at the root cause. That is, the root cause has been identified when asking "why", but only provides a limited amount of additional useful information. This method produces a linear set of causal relationships and uses the experience of the problem owner to determine the root cause and corresponding solutions

"Best Practice" Method for Formal Root-Cause Analysis

Cause and Effect Charting and Analysis

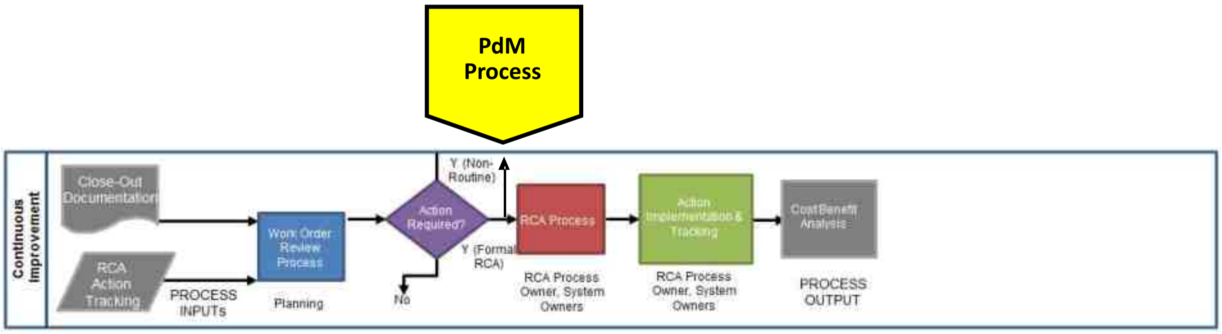
This is a simple causal process whereby one asks why of a predefined problem, answers with at least two causes in the form of an action and condition, then asks why of each answer and continues asking why of each stated cause until there are no more answers. At that time, a search for the unknown is launched and the process is repeated several times until a complete cause-and-effect chart is created, showing all the known causes and their interrelationships. Every cause on the chart has evidence to support its existence or a "?" is used to reflect an unknown and thus a risk. All causes are then examined to find a way to change them with a solution that is within control, prevents recurrence, meets goals and objectives, and does not cause other problems. The result is clear causal connections between solutions and the defined problem. Because all stakeholders can insert their causal relationships into the cause and effect chart, buy-in of the solutions is more easily attained.

Root-Cause Analysis as a Component of the Continuous Improvement Process

So far, several "Best Practice" sections have dealt with continuous improvement, continuous improvement approaches, processes, etc. Root-cause remediation is a key process element of the continuous improvement process so it makes sense to pause and first identify other key elements.

It is important to establish a continuous improvement process, which has a feedback loop. This process determines what type of work was performed, could it have been avoided, and what steps should be taken to eliminate it.

Figure 8-13: The Continuous Improvement Process

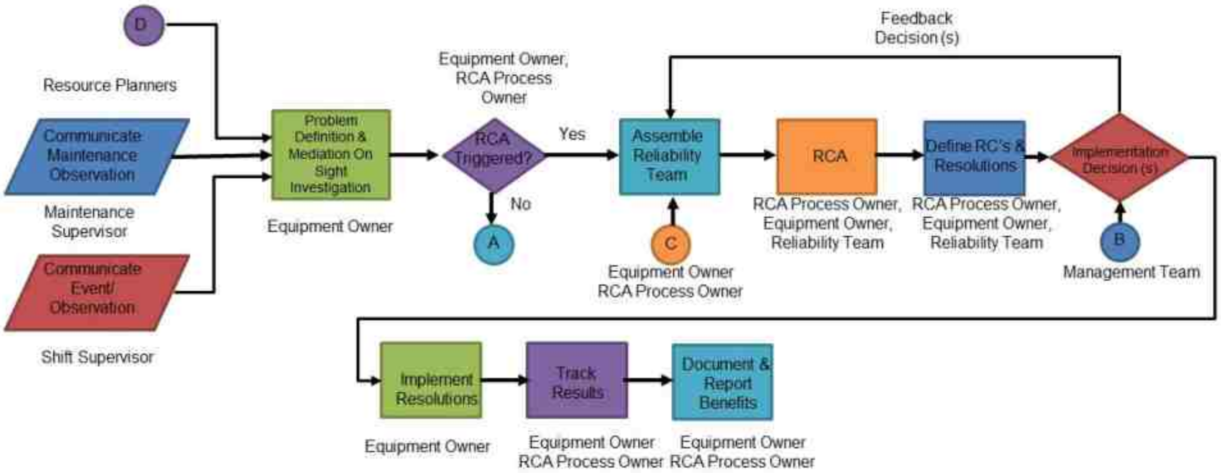


The recommended approach is (Figure 8-13):

- Implement a continuous improvement process if one is not in place. This process would make use of an occurrence management process e.g. root-cause analysis and resolution process, that is integrated into the normal work process. Some cursory investigation will reveal that there are many types of Root Cause Analysis methods – each with varying historical success deriving the root causes of different types of problems (Table 8-1).
- Then, review and implement multi-functional monitoring processes, alarms and surveillance schemes to help assure success.
- Next, review and enhance critical process and component condition indicators and performance indices. Critical processes and components should be monitored continuously and the adjustments made proactively to ensure they remain under "alert" limits.
- Finally, review, evaluate and enhance long-term plant performance indicators and goals.

Continuous improvement attributes indirectly encompass root-cause analysis. These include the root-cause process; root-cause analysis methods, resource considerations and resolution tracking.

Figure 8-14: “Best Practice” Root-Cause Analysis Process – Hawaiian Electric Company



“Best Practice” Root-Cause Analysis Program Resource Requirements

Certain resources are required for root-cause analysis to succeed. Root-cause analysis programs should include both informal and formal analysis methods and processes. Cost-based criterion must be assigned by the management team to justify more expensive formal versus lower-cost informal root-cause analysis. It should be recognized up front that anyone in the organization can make a contribution to the process. Therefore, all of the resources that could participate in and contribute to determination of root-cause should get basic training so as to be familiar with the methods that are selected as part of the process. System Owners, Maintenance, Operations and Technical leadership should receive intermediate-level formal classroom training and be allowed the time required to conduct informal and participate in formal root-cause analyses. The Root-Cause Analysis Process Owner must have advanced training in the methods and be unwavering in facilitating formal root-cause analyses to assure consistent results.

Root-Cause Process Resource Roles and Responsibilities

- Root-Cause Process Owner – Main Formal RCFA Facilitator and Manager
- System Owners (All) – Informal RCFA Facilitation, Formal RCFA Subject Matter Expert, Formal RCFA Participant
- Technical, Operations and Maintenance Leadership, Managers - Informal and Formal RCFA Participant
- Plant Personnel (All Engineering, O&M) – Informal RCFA Participants

"Best Practice" is Root-Cause Program Performance Measurement

The ability to demonstrate the success (or failure) of Root Cause Analysis (RCA) is a crucial part of incident investigation that is often missed. After all, if you do not measure performance, how do shareholders know if the program is working and whether it is worth the effort? So measuring the success of a root-cause analysis program is important both for the short-term and the long-term. In the short term, participants need to know if the changes implemented as a result of the root-cause analysis resolutions are effective. Long-term, you need the proof that the root-cause analysis program works so that the program can sustain management support.

But how is program performance measured? The goal of root-cause analysis is to improve processes or reduce the severity or impact of problems. Implementing remedial solutions without measuring the benefits is trial and error. Measuring the changes attributable to root-cause analysis solutions, both good and bad, is critical to knowing whether efforts were successful. To do this, change in the "before" and "after" states and how to measure the change is necessary to assess how effective the solution is.

Measurement of change is probably more important for the "bad" results. A negative result will show you that the problem was not understood well enough (in which case you go back to your cause and effect chart) or that poor choices were made in terms of which solutions to implement. In this way, a "bad" measure still leads to a positive outcome. It allows positive decisions to be made to revisit the issue.

So why is it that many programs fail to adequately measure success? Typically it is because the root-cause analysis process is still relatively immature, and has not yet evolved into a complete process. In these instances, deepen the commitment to grow the root-cause program and capture this crucial element. In other cases, unfortunately, measurement is simply shelved because those responsible claim to be too busy. Measuring success doesn't have to be difficult - simply identify what the program aims to achieve, and then establish both global and local success measures.

The following are examples of global measures for the root-cause program:

- Improved availability of plant (less downtime)
- Improved Equivalent Forced Outage Rate during high demand periods (EFOR)
- Less downtime when outages occur (MTTR)
- Lower frequency of problem occurrence or similar types of problems (MTBF)
- Less impact of problems – problems are less severe or the ramification of these problems are less severe (Lower O&M Costs)
- Less time spent reacting to problems and more time available for planning and making improvements (CM/PM Ratio)

The following are examples of local measures for the root-cause program:

- Ratio of total number of incidents which should trigger an RCA against how many RCAs were performed
- Percentage of solutions generated against how many were implemented
- Percentage of people who have been trained in the process against those who have actually conducted RCAs or are using the process informally
- Indication of the timeframe needed to begin investigations (shorter is better)
- Indication of the timeframe required to implement solutions

“Best Practice” Root-Cause Analysis Program Attributes

Credit Dooley/Dimmer “Best Practice” BTFR/CCIP - 2000

- Solving BTF problems is best performed by a “plant team” not by a single participant.
- Correcting the root cause (“killing” the mechanism), rather than “managing damage” from overhaul to overhaul.
- A complete “paper trail” exists for every “repeat” or serious single problem defined and verified by the mechanism and root cause(s).
- Action plans are prepared for every “repeat” BTF problem or serious single problem. Action plans are separate and distinct to (a) eliminate or mitigate the problem, and (b) to correct the root cause(s) such that problems won't reoccur in the future.
- Senior corporate and plant management are committed to mechanism identification, root cause analysis and permanent corrective action.
- Problems are quantitatively ranked and prioritized.
- There is knowledge of the O&M costs and lost generating revenues for repeat or serious problems.
- Clear direction to corporate/plant management, engineering, operations and maintenance personnel on the conduct of day-to-day activities that influence root-cause(s) of significant failures.

8.7 EQUIPMENT CONDITION MONITORING

Equipment Condition Monitoring (and Diagnostics) is diverse – it covers many aspects. This section will provide useful examples of different techniques and approaches on different types of machinery (rotating, static, heat transfer, etc.). This approach was selected primarily to illustrate and communicate the wide range of common aspects equipment condition monitoring and diagnostics possesses that are independent of equipment type.

Introduction

Boiler condition monitoring has totally changed over the last five years. No radically new concepts, new ideas or techniques have been developed, but what has changed is the speed by which we gather more diverse types of data, analyze and act on it using advanced work-saving diagnostic software capabilities.

Advancements in microprocessor, battery and signal processing technologies have allowed periodic condition monitoring, for example, of the combination of an electronic notebook, a D-meter and a sophisticated signal analyzer into a small, portable, and highly practical “smart box”. A variety of these instruments, commonly referred to as portable analyzers, are available on the market. It is the advent of these and other mobile and permanently installed devices that has turned condition monitoring from a sometimes “black art” for use by consultants and specialists, into practical, usable and highly productive operations and maintenance tools.

The huge leap in our ability to collect data at advanced speeds and in a more practical way has led to a new set of problems. Huge volumes of data that can now be gathered continuously in a short period of time need careful management if they are not to either overwhelm users, or leave valuable information hidden and wasted.

The data collector has become especially important in the field of non-destructive examination, but we must not lose sight of the many other techniques that can be used to indicate the health of a machine. Pressure, temperatures, molecular distance and position, noise emission, observation and many other techniques can all be combined and used to indicate that the health of a boiler pressure part or any other asset for that fact has changed.

A successful proactive and predictive condition monitoring program therefore encompasses not only adoption of the right technique and the right way of collecting the data in an efficient manner, but also the right data management tools to ensure that the data are correctly handled, stored and analyzed then utilized.

The major goals of the Targeted Boiler Management process are to ensure that information is collected and presented in as concise a form as possible, while giving every possible piece of information that can be used in optimizing the monitoring and inspection strategy, The system, where possible, must also allow the utilization of the wide range of in-situ data storage, retrieval and presentation requirements found in today's diverse companies.

As the whole arena of condition monitoring becomes more focused on the production area and less on maintenance, and it becomes less of a specialized department tucked away on its own, more and more people will need access to the data. Often these people are not so interested in the data that is being collected, but are interested in seeing the results and the conclusions that flow from it. A single platform for handling different types of data flowing from a variety of sources is therefore favored.

These functions need to be automated wherever possible. There are more and more demands on the time of the managers, engineers and technicians involved so, wherever possible, the computer must be left to handle as much of the routine and non-routine data management.

The Present Challenge

To understand why there has been some skepticism towards boiler condition monitoring amongst many who have tried it in the past unsuccessfully, it is necessary to understand the changes that have taken place over the last few years. Nothing has changed in the concepts, but the way in which the measurements are made has changed. In the past, the measurements were difficult and often required lugging large, heavy, and complex instruments to difficult locations and a specialist to use them. This often resulted in the use of a person whose skills were specialized in instruments or technology and not in the overall O&M strategy and planning. Their focus was on the technique and not on the results that the technique could produce.

This same bias also existed amongst the people who caused companies to make these investments. Often these were sales people from the companies who had the technology for sale – not companies whose focus was making the equipment profitable through thoughtful O&M strategies.

Over the last few years the critical change that we have seen is a move towards computer automation and software that is capable of processing the data generated by instruments and techniques into decision-making information for managers. The information can be used to achieve the true aims of a proactive and predictive strategy (i.e. increasing reliability so that the machines run from planned outage to planned outage) without hampering production, while at the same time reducing or eliminating maintenance.

"Best Practice" Approach to Condition Monitoring and Diagnostics

So what is required for good management of data in an effective proactive/ predictive program? The goal is to provide us with the maximum amount of information, in as concise a form as possible, to assist managers in planning the right strategy to get the most from machines, in this case steam generators. A person responsible for managing and optimizing a plant wants to know where the problems are, not information on every machine or item of plant that he has under his control.

The first requirement, therefore, must be to determine which machines are the ones with active or potential (incipient) problems. Typically, this is achieved by looking for exceptions in a parameter or data that differ in some way from normal operating conditions. This is usually done by simply comparing the newly acquired data with an alert (not alarm – too late) limit, or by looking for an unacceptable "step" change in a value. The computer is an excellent tool for this routine comparative work and so the automation of such tasks, together with the subsequent production of an exception report is usually a standard function of any system. However, computers will only give us good information if it is supplied with good data on which to act. The setting of the right alert levels and the collection of good quality and consistent measurements are important subjects if we are to have effective automation of the task of exception reporting. Alerts should not only detect upward change in a parameter as is typical, but also allow for decreasing parameters such as the thickness of a corroding/eroding/ tube wall. The need is to keep a parameter between limits, for example a critical temperature. The alert in this case may be the result of a parameter either increasing or decreasing.

The second requirement, flowing from the knowledge that a machine has a problem, is to determine how long before the piece/part reaches a point where it must be withdrawn from service. This is often determined by looking at how or how fast the parameters of interest are changing and by extrapolating, if the alert engine in a data management system allows automatic indication of available time left.

The third requirement is to determine what is going wrong with the component (damage modes). A common way of achieving this is by analyzing the condition inputs or precursors emanating from a machine. This can be done by breaking the condition inputs into their many component parts and matching each one with the known mechanical properties of the machine. Some of the inputs are aligned with conditions, such as the temperature, pressure, combustion byproducts, water chemistry parameters which a material is exposed to. This can often be matched to a suspected damage mechanism. Other condition inputs can be matched to other known damage mechanisms. An increase in any of these related inputs could be indicative of a damage mode. To be able to separate each of these into potential threats, we must split them into various component parts, a process often known as failure modes and effects analysis. The actual process capable of performing this function is deductive and so is logic-based. The product of these analyses is a spectrum of possible modes by which a component can fail each corresponding to mechanical, physical and/or chemical phenomena the component is exposed to. By tracking and trending each of these, changes in a specific mechanical component's condition can be tracked, as well as the overall health of the system. As with trending of overall process variables, the change in any of these can be tracked using an alert/notification system, although the process is an order more complex than the checking of single value numbers. The advantage of a good data management system is that it can usually perform the checking of these values automatically. This results in the user being able to reap the benefits without necessarily understanding the mechanisms by which it achieves its goal. As before, successful use of a computer relies on good quality data and properly set alert limits.

The Elements of a Typical Periodic Condition Monitoring System

Database

The problem with the new generation of condition monitoring systems is that they are capable of generating huge volumes of data. If we are to be able to reap the full benefits from this data, it must be held in a way that allows access to it, and retrieval of information to a user's requirements, in a fast and effective way. This is usually achieved through use of a computer database. This system has a close analogy to a filing cabinet. You may choose to keep the records for your plant in a series of cabinets, one for each section of the plant. In each cabinet will be a series of drawers, each representing a different line in the plant. Each drawer may contain many files, each corresponding to different machines. Each file may be full of information, with each page representing the current status and history of a particular part of a machine on a particular day.

The system database uses a series of hierarchies to achieve the same effect, all with the goal of finding specific data in the fastest and easiest fashion. A computer database has many advantages over the filing cabinet since, for example, it may be possible to search for all motors from given manufacturer in a specified size range. This allows us to compare one motor with many other similar motors rather than relying on the comparison of a measurement with its history in order to diagnose a problem. This can be of great importance where historical data is not available.

Routes

A major advance in recent years in the collection of condition monitoring data has been the advent of battery powered data collectors. These are digital instruments capable of being programmed with a preset series of criteria for each measurement point, which are presented to the user in a logical sequence. The effect of these data collectors has been to minimize the amount of interaction required by a user in collecting machinery condition information, even when it includes more sophisticated analysis.

Management of the collection operation is carried out in the host software designed to be used in conjunction with the collector. The efficient operation of a collector is often reliant on the management software capabilities.

An example of this is the organization of the data which we wish to collect into a logical sequence or route around the components. The physical path around the plant is minimized, even where this means making measurements on a single machine at several intervals in the sequence. Often the route or round, as it is called, is matched to a shift or half day's work. However, there is always a need to handle the practical abnormalities that inevitably occur on a plant. What happens if a stand-by boiler feed pump is operating and the primary pump is shut down? What happens if several measurements are expected at the same physical measurement location? Can the collector move smoothly from one to the next with the minimum of interaction from the operator? These seemingly small, but essential practicalities are often far more important than the specification of the electronics for the collector when considering the many options available in today's instrument market.

Another essential element of the route management is the scheduling of the right measurement at the right time. Too frequent measurements waste resources, while infrequent measurements may allow a fault to develop to the point of failure without ever noticing it. Good management of the data collection system should account for the fact that measurement intervals range from more than daily on critical machines with no stand-by, to more than three months on non-essential equipment. Obviously, on a plant with diverse machinery this can present a complex management task for which software is well suited. Typically, this involves putting the components together in groups with similar measurement intervals and then assigning a specific interval to this group within the management software. At any time the anticipated workload can then be printed out.

The work involved in using a data collector can now be reduced to the minimum. An operator is prompted to enter information or to place a transducer on the machine. He pushes a button to indicate that he is ready and whatever measurements are expected are made automatically. This includes switching the measurement instrumentation to the right set-up for the expected point. Once the measurement is completed the operator is simply instructed, through the display screen, to go to the next measurement point. All data are retained for later transfer to the computer.

Data Collection and Input

Although the data collector is today the mechanism by which the vast majority of data is entered into condition-based maintenance systems, there is additional need to integrate the data from other sources. A major limitation in the past has been that if someone wanted to use vibration measurements to indicate problems on one type of machine, such as a motor, and analysis of oil debris to look for problems on a gearbox, it often entailed using two different data management systems. This complication is slowly becoming a thing of the past, although a highly specialized focus amongst the system vendors on their own technology will continue to leave this as a problem until suitable Open Data Base Connectivity (ODBC) standards appear. A worse scenario was that time and budget constraints would force a user of condition monitoring to choose between techniques such as oil and vibration analysis because of insufficient resources to implement both.

Reporting

A major focus of the management system is to provide information on machine problems at the earliest possible time, and to ignore all data on machines that are operating within normal limits. Communication of information from a machine showing abnormal behavior is usually achieved through the exception report – a list of machines that deviate beyond the set alarm points together with an indication of how much the alarm has been exceeded. Such a list generally indicates that maintenance activities may need to be triggered. Usually trends are analyzed to ensure that sudden changes are not simply the result of bad readings. Often the next step would be issue of a work order or a similar maintenance instruction. A major advance is the integration of management systems for condition data into the broader asset maintenance management system.

Trend Plots

When a condition indicator deviates beyond the expected norms, the next step is usually investigation of the exception, first to verify that it is indeed a steady trend towards a breakdown and second, to determine the cause of the deviation. This is when graphic representation of the data in the form of trend plots proves invaluable. Where temperature patterns and chemistry parameters have been acquired, graphic relationships or complex plots including historical data are issued. This allows process changes to be examined over time. Questions that may be asked are hopefully answered by examining the trends including: How stable are the parameters? Or, is this a sudden change due to a bad measurement? Is the step-change in the parameters the result of rapid onset of a damage mechanism, or is it because we are not taking measurements at necessary intervals to detect the onset of the damage and thus give the lead time to correct that we require? Once a genuine trend towards a damage point is observed, the data can often be extrapolated to determine what period of time is available before shutdown of the machine prior to serious damage occurs.

Complex trends take more experience to interpret. This task becomes much easier where "baseline" data, taken on return to service in good condition is available. The purpose of the particular machine is to force something to happen; boiler tubes to generate steam, headers to mix it, a fan to push air; a pump to move liquid and so on. Therefore, equipment which is in good condition will always have a pattern of forces so will also have a complex pattern of parameters. If data has been collected when a component is performing its design functions a comparison can be made between this "baseline" and the current state. Where this data is not readily available, an alternative approach is to compare the problem equipment with similar equipment and look to see what parameters are approaching alert limits and why. Establishing quality alerts is the key.

Alert Limits

We have already seen that successful management of machine condition information relies on the use of alert levels to automatically reduce the huge volumes of collected data to a manageable amount, and to focus our attention onto those machines that are exhibiting some deviation from normal behavior. It is obvious that if we are to pass this data reduction task to a computer for automated analyses, we are placing a high reliance on the quality of the alert limits being set. For the novice trying to set up an equipment condition analysis system for the first time, this can present a huge amount of work in an area where he has little or no experience. There is literature to refer to but it tends to be very broad in scope and focuses on the maximum allowable limits on a machine before shutdown rather than on the level which picks up the smallest possible deviation from normal behavior.

An approach now receiving widespread acceptance is the use of baseline data collected from a machine when it is known to be in good, running condition. The computer can then analyze the data in a variety of ways, including statistical mean and standard deviation analysis, to set up an appropriate alert for each and every component. The peculiarities of the particular installation of a piece of equipment are thus accounted for, as well as the effect of the way that the machine is operated on the particular plant in which it is used. Sometimes, process variations can cause wild fluctuations e.g. water hammer, in the observed parameter which has nothing to do with a degradation of condition. In this situation, a wider acceptance margin is needed if false alerts or alarms are to be avoided. In the same way, a machine that runs the same way day after day can have very tight alert limits so that any small change will bring a potential problem to the attention of the operators. Analysis of historical data helps to set alert levels that take these variations into account.

The CMMS Interface

Proactive and Predictive condition indicators are just two of the triggers, along with response to breakdowns and calendar Intervals that result in the initiation of a maintenance task. The execution of these tasks, as well as the handling of the other triggers, is usually managed within a Computerized Maintenance Management System (CMMS). It is, therefore, a logical step to integrate these systems.

Today the lists of equipment requiring attention, or exhibiting exceptions, such as the exception report, can be passed between the systems. In some instances this can also include an indication of the type of fault, so that a specific work order can be issued. However, this concept is still trouble-prone, and still has practical limitations.

Condition monitoring and diagnostic systems are not foolproof, so false alerts may be passed right through the system if checks are not made on the data on which the alert is based. This may result in machine-overhauls simply because of a bad measurement. The consistency with which problems on equipment are trapped is not perfect even on highly optimized systems. Diagnostic technologies are only now reaching the point at which problems on machines can be definitively determined a large percentage of the time for automated issuance of maintenance instructions to be considered.

In any situation there will always be problem components and with them the occurrence of more complex issues. In these situations, not even the most sophisticated of diagnostic technology can determine why a complex mix of circumstances has resulted in the observed symptoms. All that is needed is one machine overhaul to be performed unnecessarily, due to a failure of a highly automated system attempting to perform a task that is beyond its technical capabilities, for all credibility in the emerging technology to be lost. Slowly but surely these problems are being overcome as the capabilities are developed within the software to recognize, for example, bad measurements, and handle widely varying load and speed parameters. In many instances integration of the condition monitoring and a CMMS is already proving valuable, and with the large interest in further integration of all the software involved in the current management environment, we can confidently expect that this will continue to be an area of considerable development.

The Elements of a Typical Periodic Condition Monitoring and Diagnostic System

On-line Systems

The desire to reduce the manpower involved in condition monitoring does not only apply to the automation of data analysis and diagnosis. It also applies in the area of data collection. The use of a portable data collector provides a very cost-effective means of collecting the necessary information, but it ties up human resources and is prone to human error. The installation of permanently installed monitoring transducers seems a logical progression. So why this procedure is not more widely adopted?

The answer lies in the high cost of the transducers and the extensive cabling required bringing the signals to a central point. This can often be justified where the equipment is of sufficient capital worth or if failure implications are so severe that a 'machine supervisory' system is required. This continually monitors data “streams” from the machine and can react in a number of ways and in a very short period of time. In a predictive monitoring system, the general approach is the same, and the measurements themselves may be identical, but the interval at which data needs to be evaluated is very different. In this case we are only interested in the development of a change in machines operating characteristics over several days or weeks, so for much of the time the investment in monitoring hardware is sitting redundant with considerable duplication. This situation is changing as transducer costs fall. Systems are also now exploiting the cost-effective transfer of data using local area network (LAN) and e-collaborative computer technology. Enormous advances in the use of on-line systems over the next few years are anticipated.

However, on-line systems are expensive and they should be installed in a way which makes them effective as soon as possible. The use of a data collector provides a low cost means of ensuring that transducer locations, and the type of data to be collected, are optimized relatively quickly.

Diagnostics and Expert Systems

An area of rapid development in systems for the management of equipment condition data is that of the automated diagnosis of problems. To achieve this in the past, most systems relied on data and in particular on matching of specific data parameters with a specific component. Such systems have been very successful as a guide and catalogue for the analyst but are being replaced by wider use of expert systems. Here, an attempt is made to mimic the track of multiple questions and answers that could be pursued by an expert when analyzing the wealth of information that is typically available from equipment, both through current observation, physical data and maintenance history.

Expert systems encompass a number of aspects and, as a result, have a variety of meanings and wide range of interpretations and understanding as to what is involved. Unfortunately, it is difficult to define “expert systems” in simple and precise terms. It is often claimed that if you have five experts in “expert” systems in a room, you will receive five different definitions of what they are and what they should best be used for. In actual fact, you will probably receive ten or twenty different answers.

The term 'expert' has misled many people. The idea is to have a computer system which captures the skill and expertise needed for a particular problem. The whole idea of expert systems is to use concentrated knowledge to solve a problem. Traditionally, any computer program in any language can achieve the same purpose, but it is often too difficult to incorporate the knowledge of an expert into a programming language.

Through the tools of expert systems, it is much easier to represent and manipulate this knowledge. Because of this emphasis on knowledge, most expert systems today are referred to as knowledge-based systems but, for simplicity, this section refers to the older term of 'expert systems'. With regard to the potential for expert systems in operations and maintenance, the departmental managers often want to identify where reliability problems will arise; they also need diagnostics. Many systems are able to detect that there is a problem but not what the problem is, what to do about it and when. Maintenance modules of popular CMMS operate by the use of an information management package which is responsible for the issuing of work orders. The system will be told that something is wrong with a piece of equipment machine and that it has stopped. This is hardly the information to put on a work order.

What is really needed is a more detailed analysis of the particular problem. For example, in a boiler, the condition monitoring system may detect that the level of acid and dissolved oxygen at the economizer inlet is too high. Currently it would be necessary to issue a work order to establish the cause. An expert system will assess the circumstances and perform a more detailed diagnosis automatically. It can then evaluate whether the problem is due to chemical injection, condenser and deaerator problems, to name a few. The output of the expert system can be issued as a notification with recommended actions and urgency to the operators or inserted on a work order so that the maintenance personnel know precisely the cause of the problem before action is taken. This leads to extended component life-cycle, effective and efficient action response and improved reliability.

As equipment become more complex, the task of diagnosing and analyzing problems is also becoming more complex. In fact the problems are getting so difficult that most companies are having severe problems. It is vital that expert system techniques are used to capture the diagnostics and to make the solutions available on a regular basis.

The main idea behind expert systems is to provide a more powerful means of structuring the information, and then to manipulate this information to give better and more detailed analyses.

A basic expert system implementation requires the user to capture the knowledge of the experienced operator or engineer in the form of rules which are intended to be true facts. These facts should be true in isolation and not dependent on other computer codes.

These facts are referred to as production rules, or 'if-then-else' rules, and the total system is called a rule-based system. The collection of knowledge is most commonly referred to as the rule-base or the knowledge base. A basic rule takes the following general form: if a number of items are true, then the conclusion must be true.

For example:
If the output flow rate is very low, and the pump is on, then the output filter is clogged.

Or a more complex example;
If the start-up ramp rate is too high, and tube strain is too high, and pH is low then there is a threat of corrosion fatigue. Slow the start-up temperature ramp rate and correct pH earliest possible.

Theoretically, these rules can be written down in any order and the expert system software will automatically bring them together to reach conclusions. This is one of the potential powers of an expert system, where the true facts can be specified and the program will work out how to bring them together to reach a result. In actual fact, it never works this simply, and care must be taken to determine which rules are needed and how they link together.

Another key aspect of expert systems is that the knowledge is represented symbolically, rather than numerically. In the example above, the statement 'if the output pump is on' is used. It could also be described by the statement 'if 83 = 1'. Clearly the English phrases make it much easier to read and understand. In general, expert systems use the higher level of representation with symbols rather than numbers.

A complete expert systems solution consists of the following items:

- The inference engine, which matches the current situation and expert knowledge to draw inferences by forward chaining or backward chaining.
- The rule-base containing the production rules, which describes the knowledge and contains all expert domain knowledge included in the system and the information about the current situation.
- The user interface which accepts inputs from the user and generates the displays and reports in support of dialogue and results.

The inference engine manipulates the rule-base. It understands the process by which the rules are used to reach a possible conclusion. Inference engines are standard and are independent of any particular application, only the rule-base changes.

An inference engine and a mechanism for editing and building up the rule-base is referred to as an expert system shell and this is commercially available computer software. Addition of the rules and the knowledge base allows the development of a complete application. System shells of this nature are used as the standard tools to develop expert system applications. They provide the mechanism for entering, testing and debugging rule-bases, as well as the inference engine to manipulate them. There are a wide variety of expert system shells available, from large mainframe systems using their advanced techniques, to very simple low cost PC based systems. Most modern shells also contain extensive tools for browsing and examining the knowledge base and graphically displaying what is happening. Modern tools also have standard features needed for a PC software package, such as interfaces to databases and screen paint packages.

Currently there are also a large variety of expert system products that provide good interfaces to existing data acquisition systems, databases and computer systems. These tools are particularly useful when it is desired to automatically receive data from the plant and perform a diagnosis. This further improves the availability of skilled people. It is also very important when large quantities of data are involved, for example in a database. Finally, by connecting the expert system on-line to the real plant, it is possible to have the diagnosis performed automatically at the moment of issue, rather than later when an engineer arrives. Modern expert system tools can now be interfaced to virtually any existing computer or electronic data acquisition system. The same tool can be used as a YES/NO question type system or directly interfaced on-line to the plant.

Broad-based asset management systems are now becoming a standard part of the asset management suite. Ten years ago there were few condition-based (expert) system applications for plant operations and maintenance and it was a greater risk for a manager to make the investment. The technology is now well proven and the risks are small. Since the technology is becoming more application specific, and better Integrated with condition monitoring strategies and the existing working practices, the rate of new applications is growing.

Over the next few years broader asset management system applications are likely to multiply in volume, as the more forward looking companies understand the commercial benefits they will receive, as the use of improved communication systems allow better database access and data transfer. Condition-based asset management systems are now established, and the process of applying them throughout a wide range of sectors has begun.

The Path Forward

New instruments

Lesson which users of condition monitoring systems may learn from the above (in many cases from bitter experience) is that the data that is built up in the database over the initial set-up and subsequent continual use of the system is far more valuable than the system itself. This becomes especially important as the whole science and technology of predicting machine failures advances. For example, as new techniques evolve and new instruments become available to be exploited, it should not be necessary to abandon the investment in data, history, training and experience that has already been made. This further adds to the requirement that the data be stored in a system and in a format that is or can be translated to a standard data format. An example would be the file formats used by a common database program formats such as dBase or SOL.

Management Tools

Advances in condition monitoring data management systems will continue to make condition monitoring and condition monitoring technologies easier to use, less time consuming, and provide information that is more reliable. Specifically, this will include assistance in determining what condition indicators to use for a given machine and how to measure them. This will have a dramatic effect on not only how quickly condition-based maintenance systems can be set up by a novice, but also how effective the system is and how quickly the investment in the technology is repaid.

Data validation techniques will be developed to identify bad data collection before it uses systems to issue reports and instructions with erroneous information. Like every computer-based system, if the input information is false the answer will be also – junk in, junk out.

Sharing Experiences (Monitoring and Diagnostic Center)

As the range of skills and responsibilities of plant personnel increases and diversifies, there is an opportunity for more people to have access to and interpret the data. It makes perfect sense to take advantage of existing internet and intranets to allow data to be shared. We have already experienced the benefit of looking at historical equipment data; using them to track patterns exhibited now to what has been observed before. If systems can be linked together so that significantly more data is incorporated in a single database, then the capabilities are increased.

Sources of Assistance

Many companies find that the condition monitoring technology seems beyond them, yet they have clearly identified return from its implementation. Budgets may be tight, so no investment can be made, yet proactive and predictive strategies offer a way that the company can make dramatic cost reductions. In these cases, the use of consultants can break the circle. Firstly, they have experience in the systems and techniques involved, so are able to advise on the suitability of a plant for a condition-based approach. Secondly, they are able to operate a low cost service, as they can spread investment in hardware, software and training across many companies. All that the host has to pay for is their time on and off site and travel to and from, say one week per month, plus rental of the equipment. This has the benefit of providing you with proof that the system will pay for itself once you have invested in your own equipment. More importantly, it will save you the cost of training the users before you start. They can learn the job from technology transfer as the project progresses. The investment in time to set up the database can be voided. Very often, consultants will transfer the database that they have been using, and have optimized, across to you when you purchase a system.

Consultants can also advise on all aspects of setting up a system, provide training and assist with interpretation of information in the early on. The options are wide, but the services of such companies can often make the difference between an investment that is impossible, and one where the costs are minimized and the returns maximized.

Summary

Equipment condition monitoring and diagnostics will continue to grow in popularity, not just through the advent of better technology, but because more people are prepared to make the investment in learning about a technology that seems somewhat removed from their current experience. The returns are proven and are certainly large, but as the fear of the unknown erode, resistance will evolve to support as more people discover the benefits.

There will be greater integration with all other aspects of asset management, rather than condition monitoring and diagnostic teams being small and specialized team regarded by many as "in a world of their own". Condition monitoring and diagnostics, or predictive and proactive strategies are the just in-time approaches to achieving optimal plant reliability at low cost. You repair and maintain your machines 'just-in time' to prevent a breakdown from occurring, but not at too early a point where shutting down the equipment would be financially questionable and waste resources.

8.8 CASE STUDY AT SOUTHERN COMPANY

Background

The Root-Cause Analysis (RCA) Process and the Apollo RCA Methodology was introduced in 1998 during the Plant Reliability Optimization (PRO) pilot (See Best Practice 8.2.2 Process Integration) project for Plant Reliability Optimization, PRO. It is now a plant requirement that an RCA be performed to correct any event that negatively impacts plant reliability, safety or environmental compliance.

It is well known that most problems are caused by very specific events occurring in a sequence that a single event in the chain might not have caused. The RCA team carefully develops the root causes of a candidate event utilizing Apollo's Cause & Effect methodology, then prepares recommendations for preventing and/or managing the problem.

In 1998, the RCA process was developed and only being used at Southern Company, Georgia Power's Plant Scherer. It was identified by EPRI as a “Best Practice” and was subsequently adopted into the PRO processes to support the work closeout, feedback and continuous improvement aspects. The RCA process was so successful that it was adopted at the larger plants across the Southern Company Generation fleet, and then by Southern Company's Safety Department at the core of the safety event review process.

Chevron's refinery in Biloxi gets process steam cogenerated with electricity at Southern Company, Mississippi Power's Plant Chevron. Plant Chevron is relatively small by comparison with other similar facilities but, because it has a direct customer, reliability is critical. In 2011 the RCA process was fully implemented for all reliability events at the facility. When an event occurs, a lead employee initiates the RCA procedure by assembling a team with representation from each department.

Conclusion

Because of this combination - an inter-departmental team, team work and an appropriate systematically applied method, the team will not only eliminate the particular problem but improve the overall safety, operation, design and/or efficiency of plant operations and performance.

The benefits from the RCA process include improvements in reliability, safety and environmental compliance. Since the RCA process was fully implemented at Plant Chevron, improvements in reliability and plant operations have been dominant. Another benefit achieved from the RCA process is improved communications between the plant and the customer. The customer is very interested in reliability events and assurance that corrective actions are taken. Root Cause Analysis is a required tool for any reliability-focused program.

8.9 MTTI AND MTTR METRICS

Mean Time To Inspect (MTTI) and Mean Time To Repair (MTTR) are Measures of Workforce Productivity.

Background

In today's competitive environment, efficient and effective utilization of the workforce, particularly during short outage opportunities benefits safety, unit availability and operation and maintenance costs. Tracking MTTI and MTTR as a measure workforce efficiency is a “Best Practice”. Combining equipment Mean Time Between Failure (MTBF) with MTTI/MTTR is “World Class”. Achieving optimal MTTI and MTTR for boiler pressure part inspection and / or repair minimizes the amount of time the unit must be off, if critical path, and maximizes the amount of work that can be done without extending the outage duration.

The objective is: to track productivity (efficiency x effectiveness) of the maintenance and/or technical support workforce for continuous improvement. It is used to Trend the time requirements for task mobilization, execution and de-mobilization to enable engineering, operations and maintenance analysis of efficiency and effectiveness at task-level detail (Figure 8-15).

Plant Maintenance module of SAP can be used to calculate MTTR as the difference between Malfunction start time and Malfunction end time appearing in breakdown notifications.

Figure 8-15: Developing MTTI and MTTR through Task Baselines

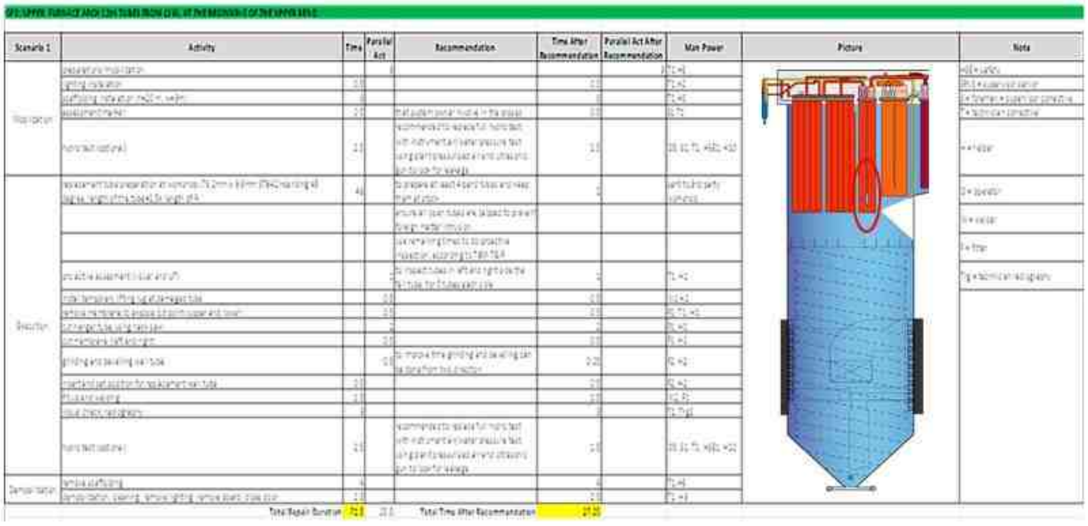
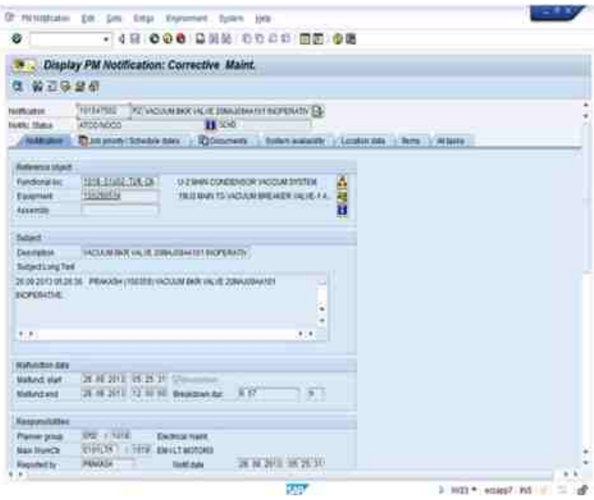


Figure 8-16: SAP Plant Maintenance Module can Calculate MTTR



Approach:

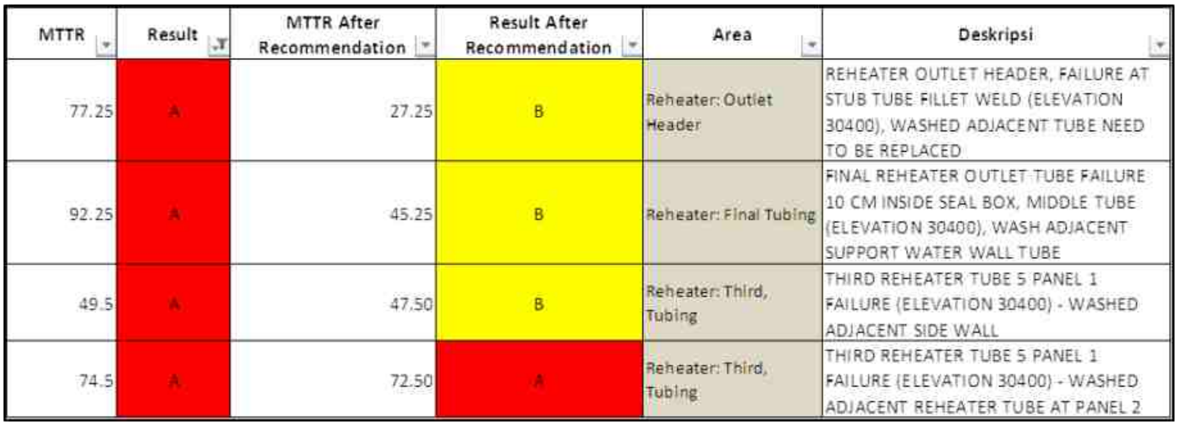
1) Build task baselines for inspection and repairs, in this case for all areas of the boiler.
    a. Prepare format for task identification, location and data collection on Excel spreadsheets.
    b. Assemble a group or groups of individuals specializing in boiler maintenance supervision, planning, rigging, welding, Quality Assurance/Quality Control (QA/QC) and Non-Destructive Examination (NDE) to work with a knowledgeable facilitator.
    c. Instruct participants in what the process is designed to do and how it does it.
        i. Define component damage and location.
        ii. Define special conditions and / or circumstances for a particular area that must be dealt with.
        iii. Record tasks, sequence, materials involved, procedural requirements, duration, manpower requirements and any parallel task requirements for the mobilization, task execution, and de-mobilization phases.
        iv. Determine if running multiple scenarios for a given area would be of value (incremental time required for multiple repairs).
        v. Choose one scenario for the group to practice on.
        vi. Proceed with scenario development for each system, component and sub-component of the boiler until it is felt that there is adequate coverage.
        vii. Scenarios for particular areas must be defined and modeled but leveraging a scenario for an area on one system felt to be identical to another by the group may be leveraged/duplicated to save time.
        viii. Completing about four scenarios on average per hour should be possible once people are comfortable with the process.
        ix. Scheduling of individuals with various skill-sets must be done before hand to avoid confusion and inefficiencies.
        x. From one to two hundred unique scenarios are possible depending on the size, configuration and complexity of the boiler circuits.
        xi. The results must be compiled for:
            1. Classification of Inspection Prioritization Index (IPI); 0-24 hour duration = "C" IPI, 24 to 48 hour duration = "B" IPI and duration greater than 48 hours = "A" IPI.
            2. Entry of MTTR and MTTI into the M&IP.
            3. Development of inspection / repair work orders, work packages, work instructions and procedures.
        d. Total duration (inspection duration = baseline MTTI, repair duration = baseline MTTR).

2) Determine risk parameters.
    a. Consequence of failure (IPI).
    b. Probability of failure (Status).
3) Build work orders for inspection and repair tasks.
4) Establish importance of care (Targeting) based on risk parameters.
    a. All work orders are outage priority but have MTTI/MTTR assigned.
    b. This drives inspection / replacement task frequencies.
    c. Assure 1:1 alignment of frequencies with M&IP.
5) Input work orders into Computerized Maintenance Management System (CMMS) (SAP, Maximo, Indus Passport, etc.).
6) Build work packages / work instruction procedures to accompany inspection / repair tasks (Electronic Library).
7) Enable CMMS scheduling.
8) Manage selection of inspection / replacement actions by aligning task (s) MTTI / MTTR with estimated outage duration, age of work order in outage backlog, Status and Inspection Prioritization Index (IPI).

Conclusion

Trend the time requirements for task mobilization, execution and de-mobilization to enable engineering, operations and maintenance analysis of efficiency and effectiveness at task- level detail.

Figure 8-17: Implementing Recommendations from Observation Yields Improved MTTR



MTTR	Result	MTTR After Recommendation	Result After Recommendation	Area	Deskripsi
77.25	A	27.25	B	Reheater: Outlet Header	REHEATER OUTLET HEADER, FAILURE AT STUB TUBE FILLET WELD (ELEVATION 30400), WASHED ADJACENT TUBE NEED TO BE REPLACED
92.25	A	45.25	B	Reheater: Final Tubing	FINAL REHEATER OUTLET TUBE FAILURE 10 CM INSIDE SEAL BOX, MIDDLE TUBE (ELEVATION 30400), WASH ADJACENT SUPPORT WATER WALL TUBE
49.5	A	47.50	B	Reheater: Third, Tubing	THIRD REHEATER TUBE 5 PANEL 1 FAILURE (ELEVATION 30400) - WASHED ADJACENT SIDE WALL
74.5	A	72.50	A	Reheater: Third, Tubing	THIRD REHEATER TUBE 5 PANEL 1 FAILURE (ELEVATION 30400) - WASHED ADJACENT REHEATER TUBE AT PANEL 2

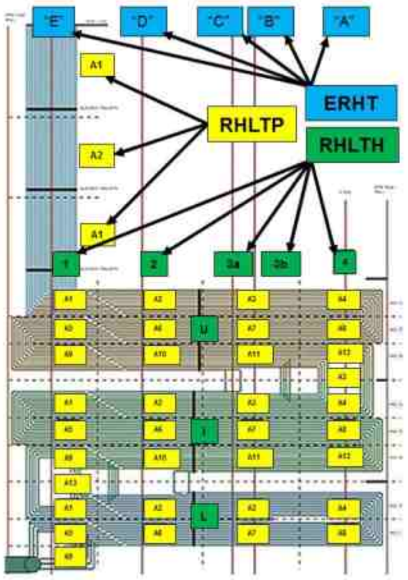
Note: Task "Baselines" (sequence, durations, manpower requirements, MTTI, MTTR, etc.) are estimates only. They require careful monitoring by responsible party's during execution. Once the tasks have been completed, the Responsible can work with Planner/Schedulers to adjust "planned" vs. "actual" task details. The Tasks now become "benchmarks" with amended MTTI and MTTRs from which to measure. productivity.

8.10 MEAN TIME BETWEEN FAILURE (MTBF) AS METRIC

Background

Tracking MTBF as a measure of reliability for boiler pressure part sub-sections is a "Best Practice". Achieving the ability to measure reliability at this level of detail will require preliminary steps be taken. Boiler pressure parts must be of manageable scope/size to allow engineers to monitor their condition and reliability. It is of limited value for the engineer to trend reliability at the "Section" level in that there is too little resolution for trending, troubleshooting and targeting corrective action. Therefore, trending reliability at the "Assembly" level is ideal; at the sub-section is acceptable (Figure 8-18).

Figure 8-18: Boiler Hierarchy



1. Boiler Section (Reheater)
2. Boiler Sub-Section (L.T. Horizontal)
3. Assembly (Upper)
4. Sub-Assembly (Element 4)
5. Area (U1A3)
6. Component (Tube 3)
7. Location (3 ft behind "E" Hanger Tube)
8. Position 3 (180)
9. Inspection Method UT

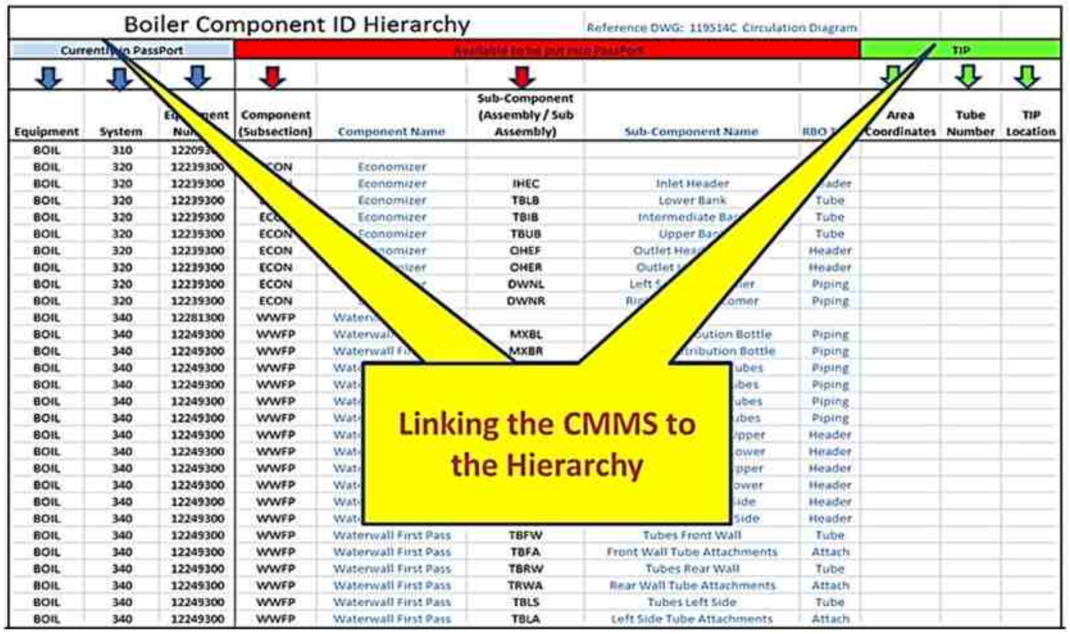
The objective and application is to track the reliability of boiler sections to prompt troubleshooting when adverse trends in reliability are sensed.

Approach:

1) Establish boiler pressure part hierarchy (Figure 8-19).
2) Create Equipment Identification Numbers (EINs) to accommodate level desired for condition monitoring (Figure 8-20).

3) The Plant Maintenance module of SAP can be used to calculate MTBF as the difference between Malfunction end time of previous notification and Malfunction start time of current notification raised for the same equipment.

Figure 8-19: Boiler Hierarchy Linked to EIN's



Boiler Component ID Hierarchy

Reference DWG: 119514C Circulation Diagram

Current/In PassPort | Available to be put into PassPort | TIP

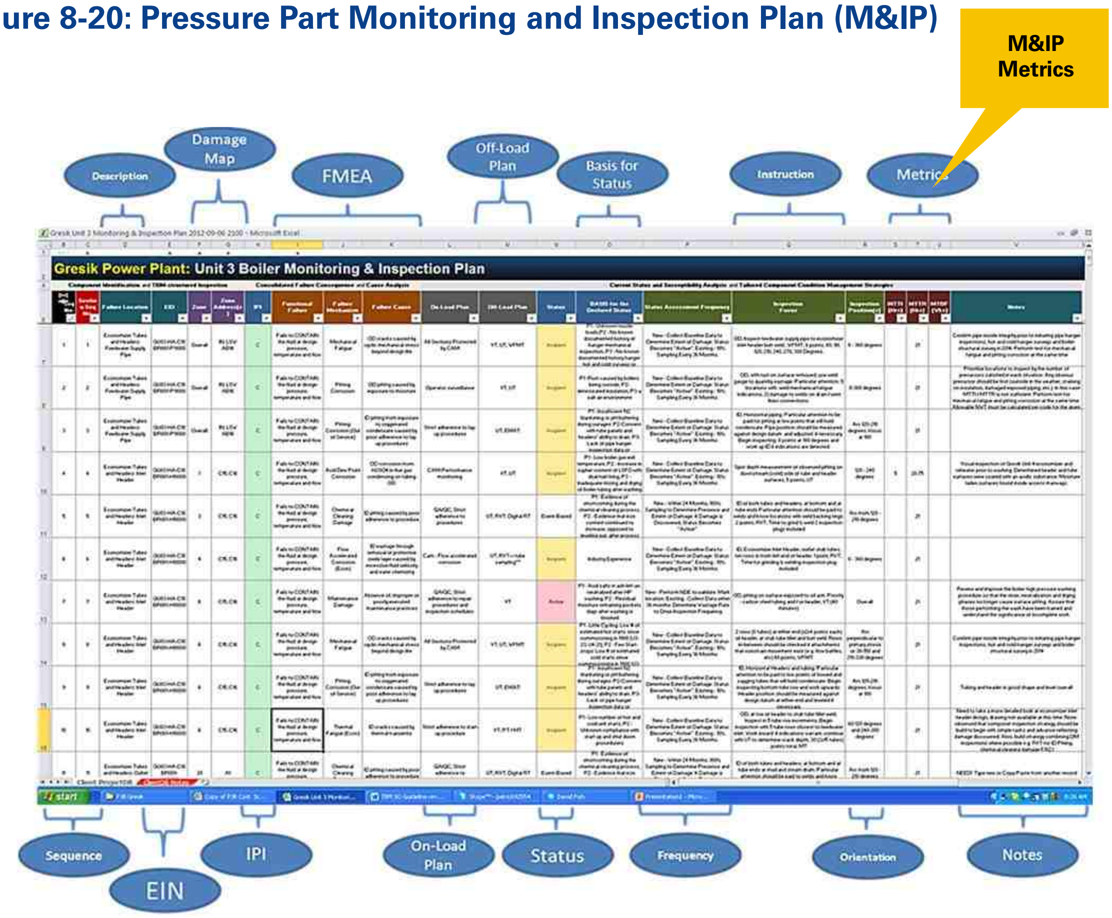
Equipment	System	Eq ment Nu	Component (Subsection)	Component Name	Sub-Component (Assembly / Sub Assembly)	Sub-Component Name	RBO	Area Coordinates	Tube Number	TIP Location
BOIL	310	12209								
BOIL	320	12239300	CON	Economizer						
BOIL	320	12239300		Economizer	IHEC	Inlet Header	ader			
BOIL	320	12239300		Economizer	TBLB	Lower Bank	Tube			
BOIL	320	12239300	EC	Economizer	TBIB	Intermediate Ba	Tube			
BOIL	320	12239300	ECON	Economizer	TBUB	Upper Ba	Tube			
BOIL	320	12239300	ECON	nomizer	OHEF	Outlet Hea	Header			
BOIL	320	12239300	ECON	izer	OHER	Outlet	Header			
BOIL	320	12239300	ECON		DWNL	Left S ner	Piping			
BOIL	320	12239300	ECON		DWNR	Rig omer	Piping			
BOIL	340	12281300	WWFP	Waterw						
BOIL	340	12249300	WWFP	Waterwal	MXBL	ution Bottle	Piping			
BOIL	340	12249300	WWFP	Waterwall F	MXBR	tribution Bottle	Piping			
BOIL	340	12249300	WWFP	Wat		ubes	Piping			
BOIL	340	12249300	WWFP	Wat		bes	Piping			
BOIL	340	12249300	WWFP	Wat		ubes	Piping			
BOIL	340	12249300	WWFP	Wat		ubes	Piping			
BOIL	340	12249300	WWFP	Wat		pper	Header			
BOIL	340	12249300	WWFP	Wat		ower	Header			
BOIL	340	12249300	WWFP	Wat		pper	Header			
BOIL	340	12249300	WWFP	Wat		ower	Header			
BOIL	340	12249300	WWFP	Wat		ide	Header			
BOIL	340	12249300	WWFP	Wat		Side	Header			
BOIL	340	12249300	WWFP	Waterwall First Pass	TBFW	Tubes Front Wall	Tube			
BOIL	340	12249300	WWFP	Waterwall First Pass	TBFA	Front Wall Tube Attachments	Attach			
BOIL	340	12249300	WWFP	Waterwall First Pass	TBRW	Tubes Rear Wall	Tube			
BOIL	340	12249300	WWFP	Waterwall First Pass	TRWA	Rear Wall Tube Attachments	Attach			
BOIL	340	12249300	WWFP	Waterwall First Pass	TBLS	Tubes Left Side	Tube			
BOIL	340	12249300	WWFP	Waterwall First Pass	TBLA	Left Side Tube Attachments	Attach			

4) Establish method of “tagging” corrective pressure part activities, preferably “time stamped” upon initiation of a work order in a Computerized Maintenance Management System (CMMS).

5) Track periodicity of corrective events over time versus pre-defined “alert” triggers.

6) Ideally, automatically trigger and notify persons responsible for responding to alerts using the boiler Monitoring & Inspection Plan (M&IP) linked to commercially available software with automated tracking metrics (Figure 3).

Figure 8-20: Pressure Part Monitoring and Inspection Plan (M&IP)



Gresik Power Plant: Unit 3 Boiler Monitoring & Inspection Plan

Conclusion

Utilize the "Lagging" Mean Time Between Failure (MTBF) metric along with "Leading" Mean Time To Inspect (MTTI) and Mean Time To repair (MTTR) metrics for trending reliability, effectiveness and efficiency.

Work Process Management for Improved Availability

9.0

9.0 Work Process Management for Improved Availability

9.1 SUMMARY

Boiler and Heat Recovery Steam Generator (HRSG) tube failures remain a major issue for the power production industry. In this chapter it is made apparent that, in fact, boiler tube failure is an "effect" not a cause. Therefore, discussions in the Summary (Section 9.1) and Tube Prevention Strategies (Section 9.2) are centered on eliminating the causes of tube and header damage and controlling propagation of the damage to meet or exceed component life expectations. A "Best Practice" approach is introduced for putting an end to tube and header failures with Targeted Boiler Management.

It is important to understand the causal factors i.e. damage mechanisms to try to understand why tube and header failure remains a problem. To do this, Section 9.3 (Coal Quality Considerations), Section 9.4 (Water Chemistry Considerations), and Section 9.5 (Metallurgical Considerations) explore the mechanisms under each as well as strategies and techniques in use to defend components against these. Detailed description of each is given to understand what is going on deep inside each component. Section 9.6 discusses operational conditions that impact tube failures and 9.7 details quality assurance and quality control considerations. Then, in Section 9.8, Boiler Condition Monitoring and Diagnostics, an overview is given on some "Best Practice" technologies (APR and Diagnostic Rules) available in the market, the conditions they help control, and how they may be used for control under different operating conditions. In addition, the technologies, tactics and "Best Practice" methods that exist to defend against them are explained. Targeted Boiler Management was developed based on what has and has not worked historically. It combines and applies these learning's from the past and combines them with evolving technology to provide the individuals that are charged with controlling tube and header failure a way to balance the computer automated and manually applied "Best Practice" tools and techniques available to them at low cost for maximum reliability.

9.2 TUBE LEAK PREVENTION STRATEGIES

9.2.1 Introduction to "Best Practice"

Background

Minimizing or eliminating fossil-fired boiler tube failures in India, like the rest of the world, represents a significant opportunity. According to EPRI, 3 percent of all oil, gas, and coal-fired power production is lost because of tube failures. The urgency of this improvement takes on additional significance in India - the average annual economic growth rate is 8 percent, more than anywhere else in the world. The economic growth in India drives this demand for electricity.

To illustrate the significance boiler tube failures have on the power production industry, take India's situation for example:

- Assume total fossil installed capacity in India is currently 139,765 MW
- Assume boiler tube failures constitute three percent of the total lost fossil power production
- Assume a plant capacity factor of 75 percent

This translates to a reduction in India's electrical demand/supply gap by the addition of approximately 4,100 MW of electricity 24 hours a day, 365 days per year.

An Industry Dilemma

Power producers have been battling boiler pressure part failures for well over a century, yet the problem remains. This flies in the face of all of the scientific work that has been done to understand the failure modes, mechanisms and causes.

- Several detailed volumes exist that are focused on the physical and chemical changes that take place with materials subjected to the boilers harsh environment.
- Technology has advanced many destructive and non-destructive methodologies for use in identifying, understanding, and trending metal damage – with some being automated.
- Standards for quality control and assurance are available to guide the user procedurally and practically.
- Boiler codes have been written and scrutinized by skilled engineers to insure that proper materials with adequate strength and dimensional tolerances and repair methods are adhered to in the factory and the field.
- The computer has revolutionized the accuracy, quantity and usefulness of data that result from various periodic tests and continuous in-service condition monitoring.

So, with all of the resources available to power plant professionals, why are boiler tube failures still a paramount problem? To answer this question, it is appropriate to examine:

- Has the industry addressed boiler tube failure defense strategies adequately?
- Are there still challenges that have not been addressed for lack of understanding?

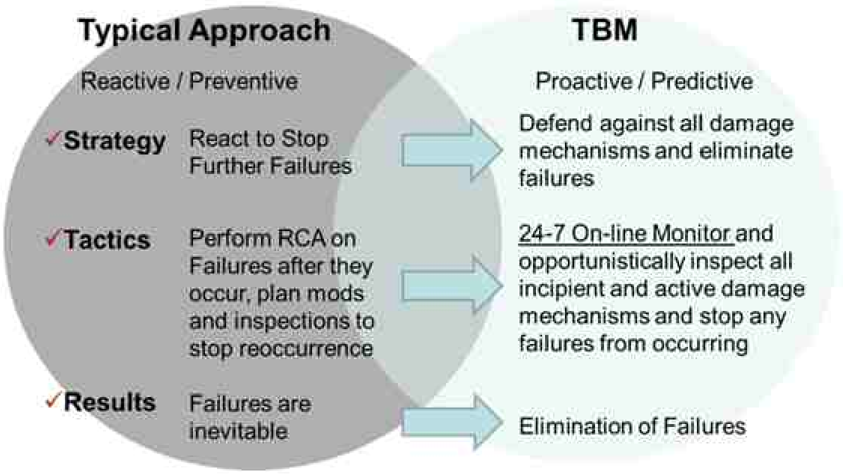
Boiler Tube Leak Defense Strategies

Introduction

Let us consider an experienced boiler pressure part System Owner tasked with creating a program to control or eliminate boiler tube failures. A strategy is normally acceptable to all when the costs to establish and maintain it are matched to the units' contribution, e.g. "Mission" and Mode of Operation. For example: a proactive/ predictive strategy requires some initial investment and a reasonable level of ongoing costs to support condition monitoring. Therefore, it would seem best suited for a large, new, base loaded unit with low operating costs. On the other hand, a preventive strategy may work fine for a small, older peaking unit with higher operating costs. The message is simple: consider economic dispatch when designing an optimal condition monitoring strategy for a particular boiler. Getting the information necessary for this consideration is easy and will save time and money.

Various strategies have evolved through time. They are chronicled first with a background for understanding the strategy and second with a description of the elements and attributes of each BTF defense strategy. The 15 "Best Practice" Targeted Boiler Management (TBM) key elements and attributes are introduced in Section 9.2.2. The evolution may be best summarized in Figure 9-1 - from "Typical" to TBM".

Figure 9-1: Best Practice Evolution from "Typical" to TBM



Reactive BTFD Strategy

Background

The reactive strategy was dominant (almost 100 percent) through 1960. Power was cheap and plentiful – "if it breaks, we'll fix it" was the predominant attitude.

Description

Adapting a reactive strategy, tube and header failures occur at random times in random locations for unknown reasons. The unit is forced out of service often and is low on the sequence of load dispatch. Tube leak failure reports are of limited value when used for reference. Technology application is limited; visual inspections and/or hydro-tests are performed prior to the unit's return to service to identify and repair undetected leaks. The extent of the damage is qualitatively estimated. Area-specific inspection and repair work plans and procedures are non-existent and on-hand repair material and skilled labor is limited. If tube materials and/or shapes are on-hand, the necessary repairs are performed; if not, then materials are located and expedited. More often than not, the leak location requires that special tube sections be fabricated and delivered to the site for installation. "Surprises" that cause additional delays, are to be expected. Repair work is not planned and very expensive. Analyses are performed to determine why the leak occurred but root cause(s) may be missed or misinterpreted. Outage timeframes for reactive repairs can be short or can extend for several days in areas that cannot be easily accessed. Pressure part reliability is un-predictable and poor because repeat failures with the same root cause often occur. Cost of repair is high due to low productivity.

Preventive BTFD Strategy

Background

Post-WW II, and prior to 1960, the military was technically developing and cutting costs. At the same time though (during the cold-war era), it was charged with staying formidable and highly reliable. Several methodologies were developed that helped accomplish this that eventually made it to the power production industry: Failure Modes and Effects Analysis and Reliability-Centered Maintenance. These were introduced to keep maintenance on more complicated machinery, inexpensive but effective – Preventive Maintenance resulted. It was adapted almost 100 percent by the regulated power industry that was facing growing public pressure to cut costs in the late 1960's through the 1970's.

Description of Preventive BTFD Strategy

Tube and header failures occur less frequently in random locations and the root causes are better understood. The unit is forced out of service less often, therefore more favored by load dispatch. Prior to entering the boiler, historical records and reports are reviewed. Tube leak failure reports are complete and of value. Non-destructive and destructive technologies and test methods are well known and appropriately applied by certified technicians under trained supervision. Hydrostatic testing is discouraged in lieu of pneumatic leak testing unless major tube sections or headers are replaced. The leak site is visually inspected to determine its origin, evidence is removed for further analyses and the extent of local damage is quantitatively determined. Root cause analysis is performed and root-cause(s) are identified. However, mitigation plans can be incomplete because assessing the extent of the latest damage may not be done thoroughly. More repair work is planned for and may be accomplished during forced outages because, during planned outages, visible tube and header damage is identified and the repairs quantitatively prioritized. There are still some "surprises" though. Knowledge of non-visible (water/steam-side or inaccessible gas-side) tube condition is limited and old remaining damage propagation is rarely trended. So a significant percentage of the work remains un-planned. Area-specific inspection and repair work plans and procedures, on-hand materials and supplies of adequately skilled laborers are all limited. However, an adequate supply of straight tubing material is in stock, is identified and well preserved. Routine repairs are performed without delays but hot-formed tube bends must be must be located and/or expedited. Cold bends are used in emergencies as a temporary repair. High-priority tube sections identified and temporary repairs (window welds, pad welds, etc.) made previously are revisited and addressed while the unit is off, if safe to do so. "Surprises" that cause additional delays are not noted in work close-out comments. Outage timeframes for forced repairs can be short or can extend for several days in areas that lack proper materials or cannot be easily accessed. Pressure part reliability is fair because repeat failures are less frequent and, at a minimum, gas-side tube conditions are better understood. The costs of repairs are still high.

Some of the Unmet Challenges

It may make sense to pause and introduce some of the challenges that were unmet in reactive and preventive BTF defense strategies. This should help the reader compare the BTF strategy in place at their power plant and gain a better appreciation for "Best Practice" proactive and predictive BTF defense strategies.

To better understand the problems still facing professionals tasked with implementing the best BTF defense strategy, consider four unmet challenges:

1. The inability to analyze the influences that off-design fuel, water chemistry and negative useful life influences (hours of operation, stress/fatigue cycles, thermal cycles, etc.) the equipment is exposed to as part of day to day operation, that manifests as damage.

2. The boiler's operating environment is extremely harsh and dynamic. It is built with several hundred miles of heat transfer tubing and piping. Scientists have identified over thirty damage mechanisms that threaten the boilers ability to contain, circulate and heat water to produce steam. Recognize that abnormal conditions, harmless at atmospheric temperature and pressure, become extremely concentrated and damaging in water and steam that is at extreme pressure and temperature.

3. Computer speed and precision must be harnessed to manage abnormal boiler conditions. Damage occurs quickly. Certain obstacles must be overcome to accomplish this on an operating boiler:

    a. When the generating unit is running well, there are long periods of time between shut-downs. Acquiring data necessary for trending component conditions are few and far between.

    b. There is very little time to get the reference data. It is normal for units capable of producing inexpensive electricity to be returned to service as soon as possible.

c. Reductions in operations and maintenance budgets and workforce due to economic pressures.

d. The glut of computer capabilities that have been installed and rendered useless in the absence of a comprehensive plan and process that integrates and applies them.

e. The belief that computers can do tasks with the same level of competency as humans, forgetting that computers must be enabled to reason to even begin to emulate humans. This was the root cause behind loss of workforce expertise that once was able to deductively interpret the meaning of unit condition indications and take intelligent, timely action.

f. Young, very capable people have replaced a seasoned workforce but the experience is sorely missed when faced with unusual conditions.

g. There is more condition data than people have time to analyze (see d and e). This diminishes the value of the investment.

4. Many boilers lack the instrumentation needed to enable continuous condition monitoring and diagnostics. Installing new instrumentation is capital intensive and sometimes difficult to economically justify.

Thus, any solution must promote a thorough understanding of the behavior of these mechanisms in this environment by dividing the boiler into smaller, more manageable pieces so that care strategies and plans, unique to each part can be designed, implemented and executed with support from available computerized information management systems. Harnessing the analogue data streams used by the units' data historian, under the digital control system (DCS) and other continuous component condition monitoring software capabilities make obvious sense.

Now that we understand more about reactive and preventive BTF defense strategies and are aware of some remaining challenges, let's understand more about advanced predictive and proactive BTF defense strategies that make up the basis for TBM. Predictive and proactive BTFD strategies are both an integral part of TBM. If, in fact, TBM is hybrid, it uses both strategies optimally. They are used as first and second lines of defense against BTF's. Proactive BTFD is the default strategy. It's attributes meet and exceed the majority of the remaining challenges outlined previously. The Proactive BTFD strategy is leveraged whenever possible in a TBM implementation. Proactive and Predictive aspects must be balanced for every boiler based on the existing BTFD strategy elements and attributes that exist. Damage mechanisms that cannot be managed proactively are dealt with predictively.

Note: From the standpoint of damage mechanisms, no two boilers are the same and should not be treated as such under any circumstances.

Predictive BTFD Strategy

Background

With the advent of microprocessors in the 1970's came portable non-intrusive condition-monitoring technologies and computers. These technologies, mostly spun-off from other industries and the military, were tried and proven for power plant applications under the most severe operating condition of the day - at EPRI's Monitoring & Diagnostic Center located at Exelon's Eddystone Station Units 1 and 2. Interesting to note was that Eddystone Unit 1's initial steam conditions were 345 bar at 593°C! With EPRI's development of an organizational and process framework at the center in the mid-1980's through 1996, Predictive Maintenance began and remains very popular

Description of Predictive BTFD Strategy

Utilizing this strategy, boiler tubes seldom fail (see Proactive BTFD). A unit is more favored by the unit dispatcher. If failures do occur, like a thunder strike, a thorough investigation is conducted to determine root-cause(s) and to understand what aspect(s) of the boiler's out of service Monitoring & Inspection Plan and/or in service Monitoring and Diagnostic Plan failed. The plans are immediately modified to correct the fault as well as changes being made to the affected inspection packages, procedures and diagnostic logic. This is essential because following the plans defends the boilers pressure parts against damage. The extent of damage is quantitatively defined and all repair work is planned. Work packages and procedures for inspection and repairs in each area of the boiler are accurate and kept current. Tube leak failure reports are electronic and thoroughly documented. Data, photos, maps, materials, etc. for each location is readily available. Pressure part plan, elevation, assembly and detail drawings are current and available electronically. The System Owner possesses a complete and current set of drawings that are laminated for long life and heavy usage. Prior to entering the boiler, the current tube/header inspection and repair outage backlog, the in-service 'continuous" information management tool, and the out of service "periodic" information management tool are referenced for current status. This provides the System Owner with inspections that are high priority, overdue and fit the outage duration to sponsor at the outage planning meeting. Also, understanding of the chemical and physical boiler parameters that have been out of acceptable limits is necessary to guide incipient damage inspections and trends of active damage and risks also for sponsorship. High-priority inspections and repairs are accomplished safely at the same time as other repair work and within the outage time window. Non-destructive and destructive technologies and test methods are well known and appropriately applied by certified technicians under trained supervision. Hydrostatic testing is performed only after major tube sections or headers are replaced. All welds are inspected using digital radiography. Pneumatic tests are performed before and after tube/header work. The current tube and header metallurgical and weld condition and visible and non-visible surface conditions are understood. Active damage propagation is trended and extrapolated as are deposit thickness measures so that repairs and chemical cleaning may be extrapolated, planned and risk-prioritized. Incipient damage is monitored in two ways: with the unit in service by measuring and trending damage precursors and with the unit out of service through specialized testing of a sample population in vulnerable locations. Condition-monitoring data is available to both local and global technical experts over the internet. Company and contract skilled labor is readily available. Durations for forced and planned outages are optimized and carefully controlled. Durations of tube/header inspection and repair activities are documented and easily accessed. Task benchmarks have been established in each tube/header location to measure workforce productivity. Mean Time To Inspect (MTTI) is used as a productivity measure for inspections and Mean Time To Repair (MTTR) for repairs. Total duration is measured and tracked for each so that they can be planned for work during outages of a given duration. Task benchmarks have also been established in each tube/header location to provide part of the "consequence" variable for risk evaluation. The total duration of the inspection and repair activities provides the time required from "gas-path ready-to-gas-path closed". An adequate supply of straight tubing and hot-bends of the most strategic diameters, wall thicknesses and bend radiuses are in stock and kept well preserved. Routine repairs are performed without delays. Any exceptions or "Surprises" that occur during work are noted in the work order and corrected. Pressure part reliability and costs are balanced near optimal but experienced technical resources must be continually available to support a Predictive Strategy.

Proactive BTFD Strategy

Background

U.S. Patent No. 8,442,853 Issued May 13, 2013

Targeted Equipment Monitoring System and Method for Optimizing Equipment Reliability

Webster's Dictionary defined "Proactive" in 1933 as "acting in anticipation of future problems, needs, or changes". In the case of TBM, proactive is acting to stop the initiation of damage to boiler tubes and headers. Damage mechanisms have precursors that signal the threat. By understanding and monitoring precursors we can manage equipment condition. Understanding precursors means: how they can be measured, what acceptance limits are, how limits can change with changing circumstances or environments, if a single precursor can initiate damage or if it takes several and if precursors have to act serially or in parallel. By understanding damage and its precursors, logic can be built to warn that "conditions are right" for damage initiation or propagation.

Description

If failures occur, the extent of damage is quantitatively defined. A thorough investigation is performed to determine root-cause(s) and to understand what aspect(s) or assumptions, if any of the boilers' in service Monitoring and Diagnostic Plan were incorrect. The Plan is immediately modified to correct the fault as well as changes made to the affected diagnostic logic. This is essential because following the plans defends the boiler's pressure parts against damage. Boiler pressure parts are equipped with precision electronic sensors that provide accurate inputs for continuous condition monitoring. Sensors have been inventoried, modeled and mapped for proactive diagnosing of damage mechanisms. The System Owner, located on-site and the Subject Matter Experts (SMEs) at centralized Monitoring & Diagnostic Centers are electronically notified of impending problems. The System Owner and SMEs provide the best technical support to the control room operators. Together they intervene to bring the targeted parameters back into allowable limits, hopefully before damage is initiated. Pressure part reliability, costs and resource requirements are optimal when predictive and proactive strategies are combined.

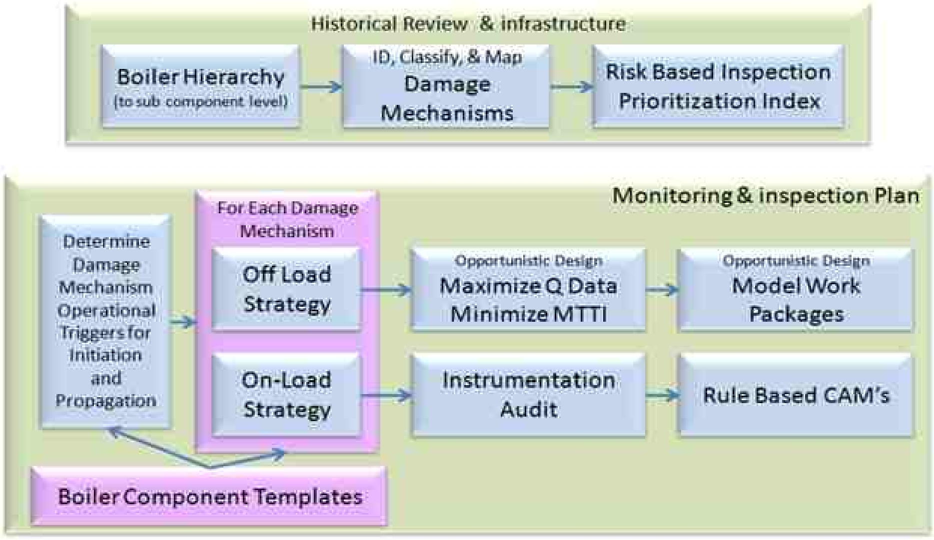
Proposed Solutions

In consideration of the challenges that remain and from each strategy's strengths and weaknesses based on performance history and of the tools and techniques now available, the BTFD strategy "bar" should be raised – The new strategy must not only reduce but substantially eliminate boiler tube and header failure. Targeted Boiler Management (TBM) is designed to do exactly that (Figure 9-2).

Targeted Boiler Management – TBM uses tube and header failure modes, causes, and mechanisms to organize proactive and predictive mitigation tasks that eliminate or substantially reduce failures through component condition monitoring plans. Being proactive prevents the onset of new damage and being predictive slows the propagation of existing damage. TBM failure defense philosophies and strategies use analytical software that prompts the user of the equipment, the benefactor, to provide particular fixed and variable inputs to produce tailored reliability schemes. The schemes produced, in turn:

- Attack active damage
- Prevent new damage
- Enable awareness of incipient damage
- Enable preparation with plans for event-based damage

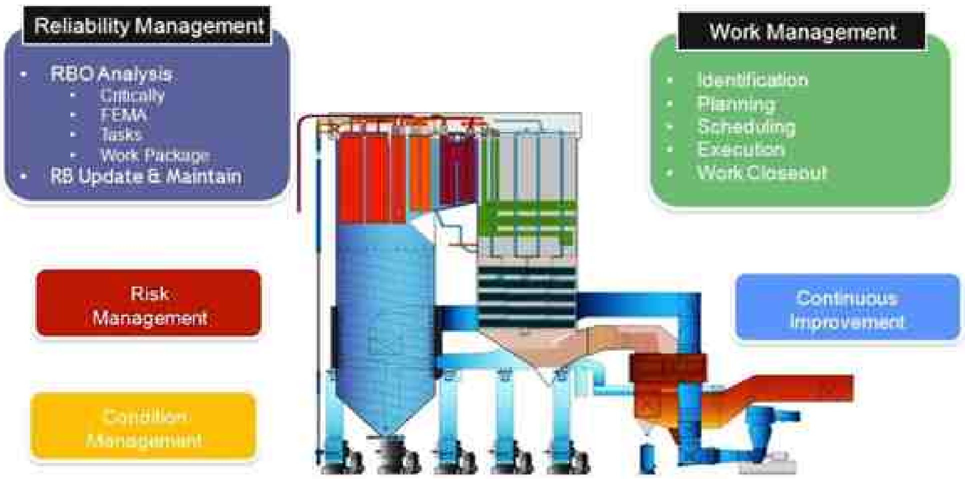
Figure 9-2: Targeted Boiler Management Approach



Targeted Boiler Management is designed with 15 key elements so that resources are leveraged; mitigation plans are ingrained into and sustained by plant work processes, all existing technology is optimally utilized and new computer technology economically justified.

Targeted Boiler Management enlists all of the aspects of more conventional asset management processes but has been adapted specifically for boiler and other heat exchanger pressure parts and high energy piping (Figure 9-3).

Figure 9-3: TBM - Asset Management for Boiler Pressure Parts



With this in mind, proposed solutions to the aforementioned challenges outlined above are:

1. An analytical software "engine" utilizing inputs of specific sets of fixed and variable data that, through standard mathematical calculations, yields the damage mechanism that threatens and the relative probability of damage expected to boiler components exposed to these conditions. This application would enable preliminary understanding and mapping of corresponding incipient and active damage in boiler care plans and strategies.

2. A system that utilizes area-specific alphanumeric strings that couple existing equipment identification nomenclature in the CMMS with the associated test and inspection strategies for easy management of the unusual volumes of data that will result and clear inter-departmental communications when actions are requested in a particular area.

3. A software application that not only monitors component conditions, but carries out diagnoses of sensed anomalies to the extent possible so people are less burdened.

    a. It will take continuously streamed data (static and dynamic steam or gas pressures, flows, temperatures, draft) from the DCS data acquisition system and third-party software with condition inputs,

    b. It will group data logically by precursors that can lead to each of many damage mechanisms, then filter it in order to "flag" signal anomalies,

    c. It corrects the data for unit load conditions to assure relativity and repeatability,

    d. It will convert it to more useful condition indicators (ΔT, ΔP, etc.),

    e. It will send the condition indications to a "smart" Boolean rule base that contains logic written to alert the end user (operator, system owner, plant manager, etc.) when a precursor or precursors exist that are out of acceptable range to mimic creation of damage,

    f. This yields monitoring and diagnoses of impending damage with reasonable likelihood (Time out of compliance) and type (complex data variations/combinations) of damage to be expected to boiler components by operating under these circumstances as a first step to understanding and mapping potentially active damage that would result.

4. Condition monitoring and diagnostic modeling form the foundation for economic justification of new instrument additions and existing instrumentation refurbishment. Computer models may align instrument requirements needed for on-line, proactive mitigation of all known and incipient component-specific damage mechanisms. This would tie the on-load component condition monitoring plan and strategy directly to the negative reliability, O&M and capital replacement cost impacts for use in justifying expenditures for

hardware installation through the ability to construct cost to benefit, point of net value and breakeven relationships. Seeming apparent, this practice is limited or non-existent because of the absence of a "big picture", component-specific boiler tube and header failure plan and strategy. Once the instrumentation needs are identified and satisfied, the signals will feed additional rules to cover proactive diagnostics outlined in Solution #3.

Targeted Boiler Management incorporates the proposed solutions.

Conclusion

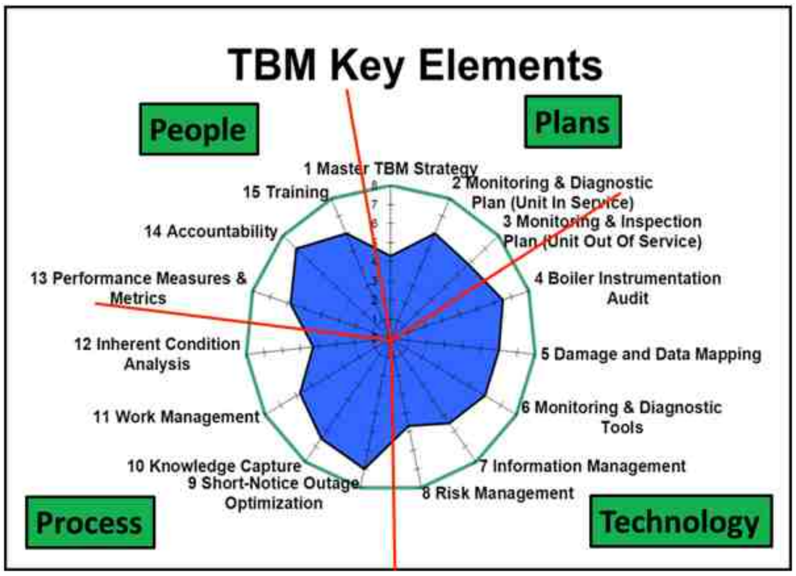
Targeted Boiler Management simply ties together all 15 of the essential elements a program requires to accomplish its objective – minimize or eliminate tube and header failures. However, each element has an assortment of "Best Practice" attributes. The quality and dedication an organization invests in implementing attributes will be reflected in the degree boiler tube failures are reduced or eliminated. A review of Targeted Boiler Management's key elements and attributes follows in Section 9.2.2.

9.2.2 Key Elements and Attributes of TBM

Background

As mentioned previously, Targeted Boiler Management simply ties together 15 of the essentials: classifications, key elements, and "Best Practice" attributes a program requires to accomplish its objective – minimize or eliminate tube and header failure consequences. It is appropriate that the reader gain a clear understanding of each of these in order to understand how to implement a successful TBM Program.

Figure 9-4: TBM Element Classifications and Key Elements – Spider Assessment Diagram



There are four logical ways to classify the 15 Key Elements. These classifications have been proven effective in assessing needs and assembling implementation plans and schedules. They are defined:

1. People: For understanding organizational roles and responsibilities, leveraging the organization through teamwork and training for proficiency in process functions
2. Process: For optimizing resources and condition monitoring opportunities using a structured approach
3. Plans: For organizing and balancing the defenses necessary to achieve stated objectives cost effectively
4. Technology: For detailing the application of periodic and continuous monitoring and diagnostic technologies that are necessary for pressure part condition oversight.

Each classification has pertinent key elements as shown in Figure 9-5.

Figure 9-5: TBM Classifications and Key Elements

Plans

- Key Elements
  1. **Master TBM Strategy**
  2. **Monitoring and Diagnostic Plan (Unit In-Service)**
  3. **Monitoring and Inspection Plan (Unit Out-of-Service)**

Technology

- Key Elements
  4. **Boiler Instrumentation Audit**
  5. **Damage and Data Mapping**
  6. **Monitoring and Diagnostic Tools**
  7. **Information Management**

Process

- Key Elements
  8. **Work Management**
  9. **Knowledge Capture**
  10. **Short-Notice Outage Optimization**
  11. **Risk Management**
  12. **Inherent Condition Analysis**

People

- Key Elements
  13. **Accountability**
  14. **Measures & Metrics**
  15. **Training**

For the purposes of brevity and to promote clear understanding, the key elements and "best practice" attributes will be presented in a hierarchical format and defined as:

- **Element Number: 1** – 15 (CW on Assessment Spider)

    Element Classification: (CW on Assessment Spider) Plans, Technology, Process or People

        Element Description: Label Used for TBM Key Element

        Element "Best Practice" Attribute(s): Characteristic or Behavior Demonstrated by Organizations considered "Best Practice" adoptors

The explanation of each TBM Key Element, beginning with PLANS are illustrated in the following figures:

Element Number: 1

    Element Classification: Plans

        Element Description: Master TBM Strategy

            Element "Best Practice" Attribute(s):

1. A Master TBM Strategy is active and is aligned with the unit's mission and directed through on-load and off-load Monitoring & Inspection Plans

Figure 9-6: Boiler Master Monitoring and Inspection Plan & Strategy (In Excel)

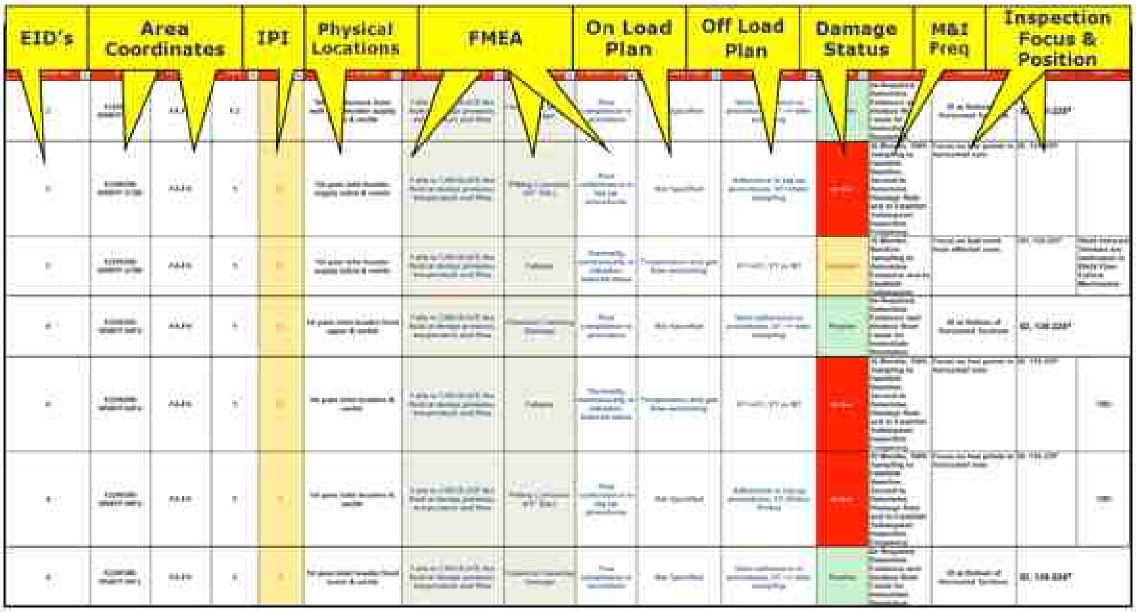
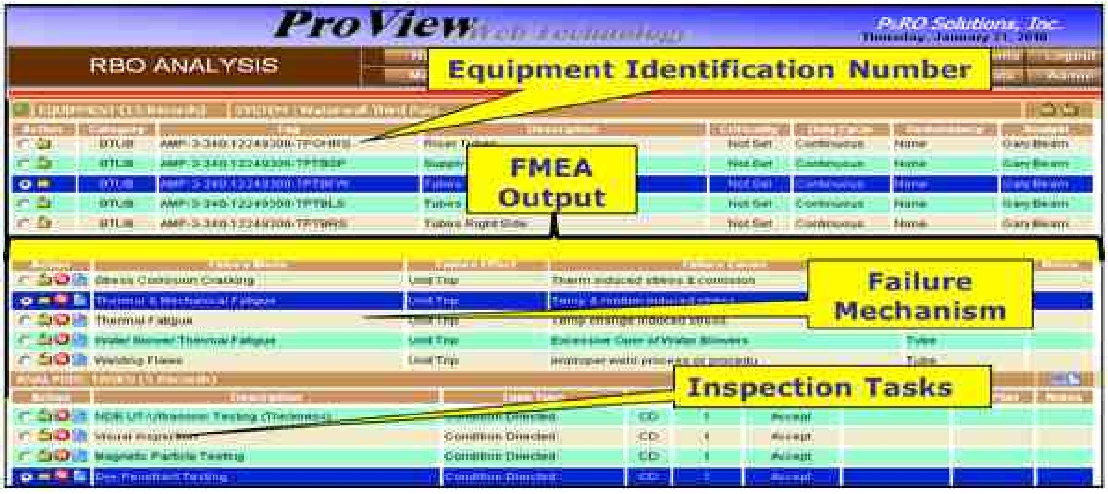


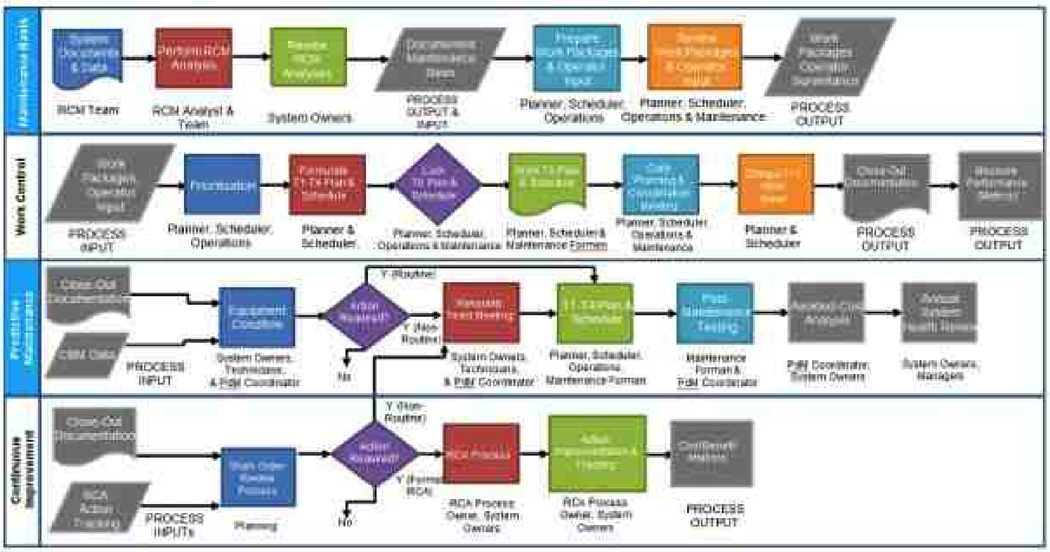
Figure 9-7: Boiler Master Monitoring and Inspection Strategy (In P&RO Solutions' ProView)



2. A Master TBM Strategy must exist for each boiler and be recognized as the way of managing the boilers reliability

3. The Master TBM Strategy, with accompanying plans, must be integrated into the plant work processes for "Grass Roots" organizational support to assure efficiency and effectiveness

Figure 9-8: Typical Plant Work Process Flow Diagrams



Element Number: 2

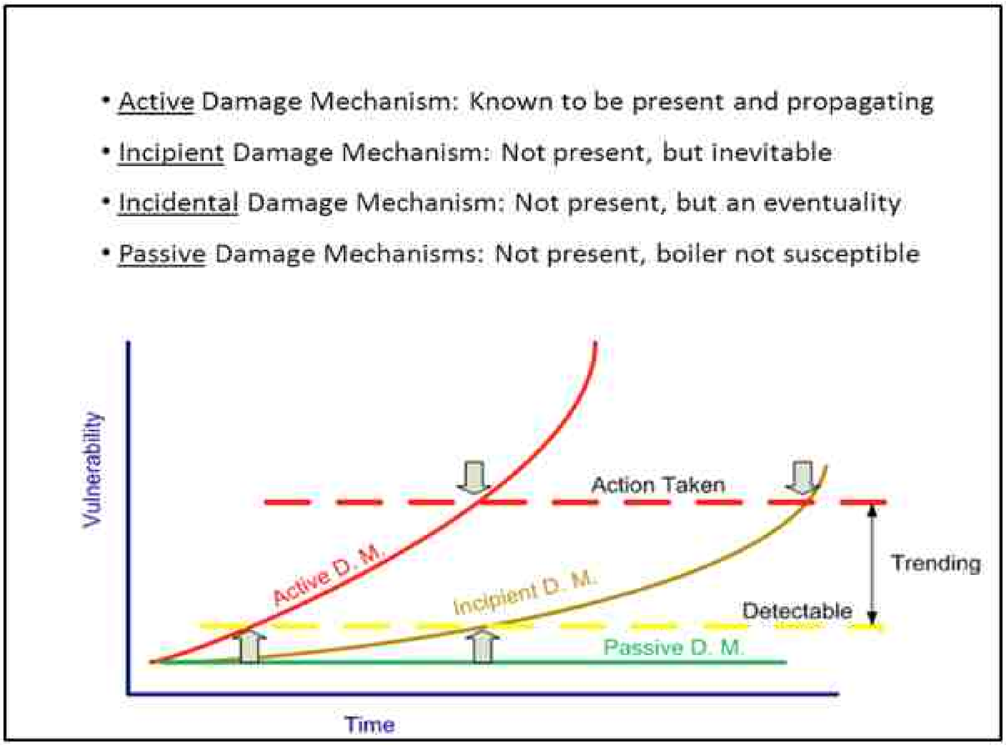
Element Classification: Plans

Element Description: Monitoring and Diagnostic Plan (Unit In-Service)

Element "Best Practice" Attributes:

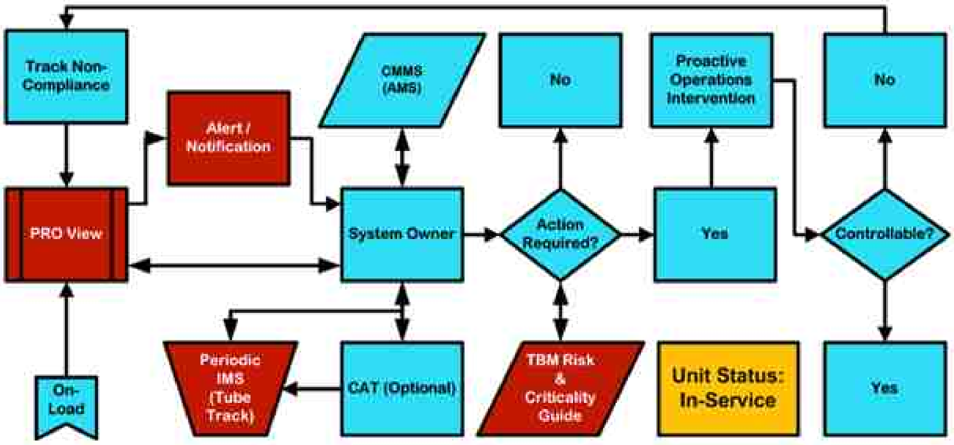
1. A person, hereafter called a "System Owner", responsible for the reliability of the equipment is in place and trained.
2. A tool in place to automate condition monitoring and diagnosis based on boiler instrumentation signal inputs.
3. An operations and engineering team in place to support the In-Service Monitoring and Inspection Plan and the System Owner.
4. A proactive process to drive quick action should be in place and include:
    - Real-Time Information Management
    - Anomaly Notification and Timely Correction
    - Communication protocols with Control Center Operators
    - Periodic Program Review of Alerts, Diagnostic Rules and Performance Metrics
    - Anomaly Historian to Time-Stamp Events

Figure 9-9: A System Owner Manages Damage Mechanism Status Against Reliability Risks



- Active Damage Mechanism: Known to be present and propagating
- Incipient Damage Mechanism: Not present, but inevitable
- Incidental Damage Mechanism: Not present, but an eventuality
- Passive Damage Mechanisms: Not present, boiler not susceptible

Figure 9-10: Proactive In-Service Monitoring and Diagnostic Response Plan



Element Number: 3

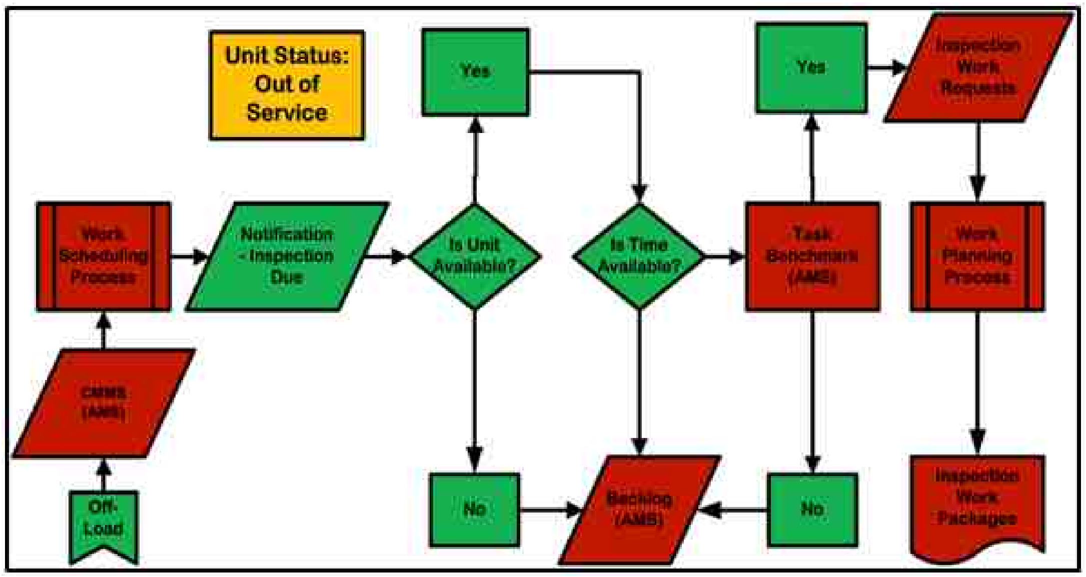
Element Classification: Plans

Element Description: Monitoring and Inspection Plan (Unit Out-of-Service)

Element "Best Practice" Attribute(s):

1. A System Owner, responsible for the reliability of the equipment, in place and trained.

Figure 9-11: A System Owner Uses a Similar Process to Determine Tasks to Perform During Short-Notice Outages



2. A process for converting periodic condition data into useful information to drive timely decision-making should be in place and functioning.

    - Maintenance effective in coordinating inspection access, site inspection preparation, scaffold R&R and securing worksite
    - Inspectors efficient in performing quality inspections in precise locations, per work package instruction and process owner's scope and within the agreed-upon timeframe
    - Inspectors proficient in working with System Owner to input data into Out of Service information management system

Element Number: 4

Element Classification: Technology

Element Description: Boiler Instrumentation Audit

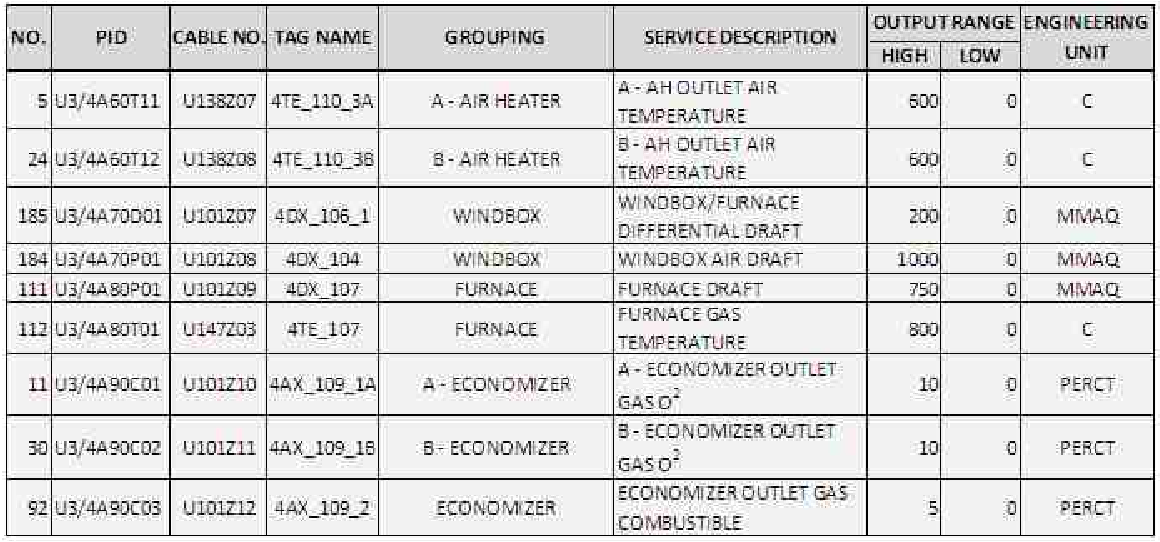
Element “Best Practice” Attribute(s):

1. Gaps between existing instrumentation and that needed for monitoring of active or incipient primary damage mechanisms are defined
2. Existing defined instrumentation is repaired and made serviceable
3. Non-existing, yet defined instrumentation has been economically analyzed. Justified instrumentation is procured, installed, tested and mapped to the in-service monitoring & inspection plan

Example: Approach used for boiler instrumentation audit:

1. Request input/output listing of available analogue instrumentation. Two purposes will be served by this: 1) use in condition modeling and 2) use in correction for machine output

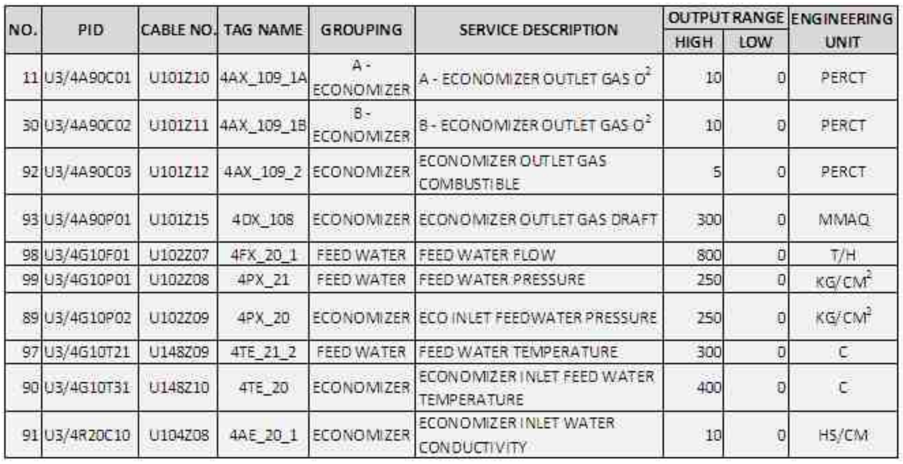
Table 9-1: Input/Output Listing of Available Analog Instrumentation



NO.	PID	CABLE NO.	TAG NAME	GROUPING	SERVICE DESCRIPTION	OUTPUT RANGE		ENGINEERING UNIT
						HIGH	LOW	
5	U3/4A60T11	U138Z07	4TE_110_3A	A - AIR HEATER	A - AH OUTLET AIR TEMPERATURE	600	0	C
24	U3/4A60T12	U138Z08	4TE_110_3B	B - AIR HEATER	B - AH OUTLET AIR TEMPERATURE	600	0	C
185	U3/4A70D01	U101Z07	4DX_106_1	WINDBOX	WINDBOX/FURNACE DIFFERENTIAL DRAFT	200	0	MMAQ
184	U3/4A70P01	U101Z08	4DX_104	WINDBOX	WINDBOX AIR DRAFT	1000	0	MMAQ
111	U3/4A80P01	U101Z09	4DX_107	FURNACE	FURNACE DRAFT	750	0	MMAQ
112	U3/4A80T01	U147Z03	4TE_107	FURNACE	FURNACE GAS TEMPERATURE	800	0	C
11	U3/4A90C01	U101Z10	4AX_109_1A	A - ECONOMIZER	A - ECONOMIZER OUTLET GAS O^2	10	0	PERCT
30	U3/4A90C02	U101Z11	4AX_109_1B	B - ECONOMIZER	B - ECONOMIZER OUTLET GAS O^2	10	0	PERCT
92	U3/4A90C03	U101Z12	4AX_109_2	ECONOMIZER	ECONOMIZER OUTLET GAS COMBUSTIBLE	5	0	PERCT

2. Inventory available instrumentation; sort by system, equipment and usage - draft loss, flow measurement, temperature measurement, pressure measurement, etc., (See Table 9-2).

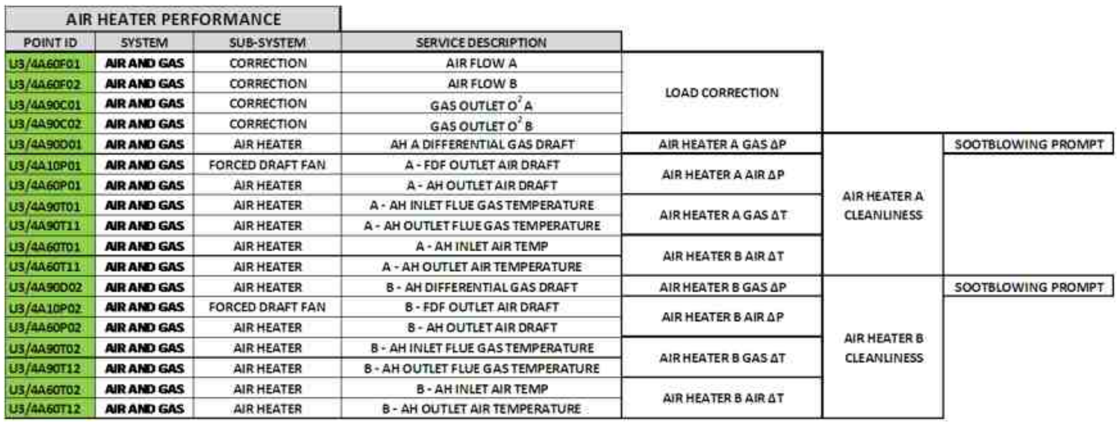
Table 9-2: Inventory Available Instrumentation - Sorted by System, Equipment and Usage



NO.	PID	CABLE NO.	TAG NAME	GROUPING	SERVICE DESCRIPTION	OUTPUT RANGE		ENGINEERING UNIT
						HIGH	LOW	
11	U3/4A90C01	U101Z10	4AX_109_1A	A - ECONOMIZER	A - ECONOMIZER OUTLET GAS O^2	10	0	PERCT
30	U3/4A90C02	U101Z11	4AX_109_1B	B - ECONOMIZER	B - ECONOMIZER OUTLET GAS O^2	10	0	PERCT
92	U3/4A90C03	U101Z12	4AX_109_2	ECONOMIZER	ECONOMIZER OUTLET GAS COMBUSTIBLE	5	0	PERCT
93	U3/4A90P01	U101Z15	4DX_108	ECONOMIZER	ECONOMIZER OUTLET GAS DRAFT	300	0	MMAQ
98	U3/4G10F01	U102Z07	4FX_20_1	FEED WATER	FEED WATER FLOW	800	0	T/H
99	U3/4G10P01	U102Z08	4PX_21	FEED WATER	FEED WATER PRESSURE	250	0	KG/CM^2
89	U3/4G10P02	U102Z09	4PX_20	ECONOMIZER	ECO INLET FEEDWATER PRESSURE	250	0	KG/CM^2
97	U3/4G10T21	U148Z09	4TE_21_2	FEED WATER	FEED WATER TEMPERATURE	300	0	C
90	U3/4G10T31	U148Z10	4TE_20	ECONOMIZER	ECONOMIZER INLET FEED WATER TEMPERATURE	400	0	C
91	U3/4R20C10	U104Z08	4AE_20_1	ECONOMIZER	ECONOMIZER INLET WATER CONDUCTIVITY	10	0	HS/CM

3. Develop models for coupling condition monitoring inputs with precursors to the associated damage mechanism they will help in protecting against (See Table 9-3).

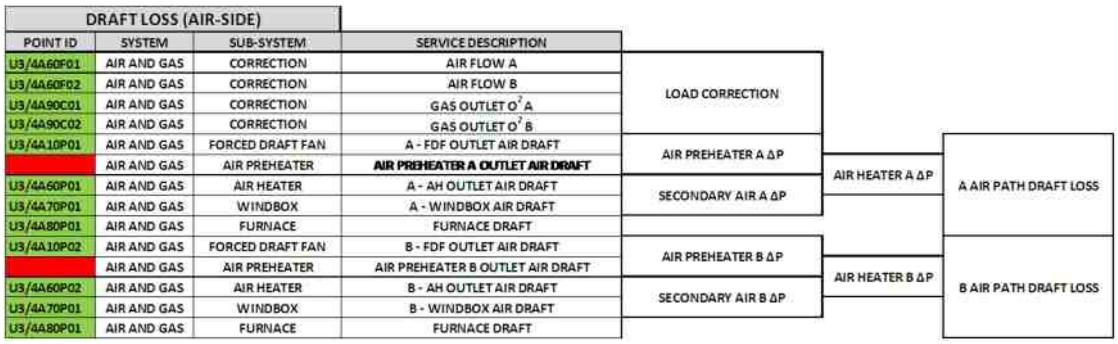
Table 9-3: Model for Coupling Condition Monitoring Inputs with Precursors



AIR HEATER PERFORMANCE						
POINT ID	SYSTEM	SUB-SYSTEM	SERVICE DESCRIPTION			
U3/4A60F01	AIR AND GAS	CORRECTION	AIR FLOW A	LOAD CORRECTION		
U3/4A60F02	AIR AND GAS	CORRECTION	AIR FLOW B			
U3/4A90C01	AIR AND GAS	CORRECTION	GAS OUTLET O^2 A			
U3/4A90C02	AIR AND GAS	CORRECTION	GAS OUTLET O^2 B			
U3/4A90D01	AIR AND GAS	AIR HEATER	AH A DIFFERENTIAL GAS DRAFT	AIR HEATER A GAS ΔP	AIR HEATER A CLEANLINESS	SOOTBLOWING PROMPT
U3/4A10P01	AIR AND GAS	FORCED DRAFT FAN	A - FDF OUTLET AIR DRAFT	AIR HEATER A AIR ΔP		
U3/4A60P01	AIR AND GAS	AIR HEATER	A - AH OUTLET AIR DRAFT			
U3/4A90T01	AIR AND GAS	AIR HEATER	A - AH INLET FLUE GAS TEMPERATURE	AIR HEATER A GAS ΔT		
U3/4A90T11	AIR AND GAS	AIR HEATER	A - AH OUTLET FLUE GAS TEMPERATURE			
U3/4A60T01	AIR AND GAS	AIR HEATER	A - AH INLET AIR TEMP	AIR HEATER B AIR ΔT		
U3/4A60T11	AIR AND GAS	AIR HEATER	A - AH OUTLET AIR TEMPERATURE			
U3/4A90D02	AIR AND GAS	AIR HEATER	B - AH DIFFERENTIAL GAS DRAFT	AIR HEATER B GAS ΔP	AIR HEATER B CLEANLINESS	SOOTBLOWING PROMPT
U3/4A10P02	AIR AND GAS	FORCED DRAFT FAN	B - FDF OUTLET AIR DRAFT	AIR HEATER B AIR ΔP		
U3/4A60P02	AIR AND GAS	AIR HEATER	B - AH OUTLET AIR DRAFT			
U3/4A90T02	AIR AND GAS	AIR HEATER	B - AH INLET FLUE GAS TEMPERATURE	AIR HEATER B GAS ΔT		
U3/4A90T12	AIR AND GAS	AIR HEATER	B - AH OUTLET FLUE GAS TEMPERATURE			
U3/4A60T02	AIR AND GAS	AIR HEATER	B - AH INLET AIR TEMP	AIR HEATER B AIR ΔT		
U3/4A60T12	AIR AND GAS	AIR HEATER	B - AH OUTLET AIR TEMPERATURE			

4. Identify missing input parameters that, if considered, would optimize the ability to monitor pressure part condition using inputs considered damage precursors (See Table 9-4, in red).

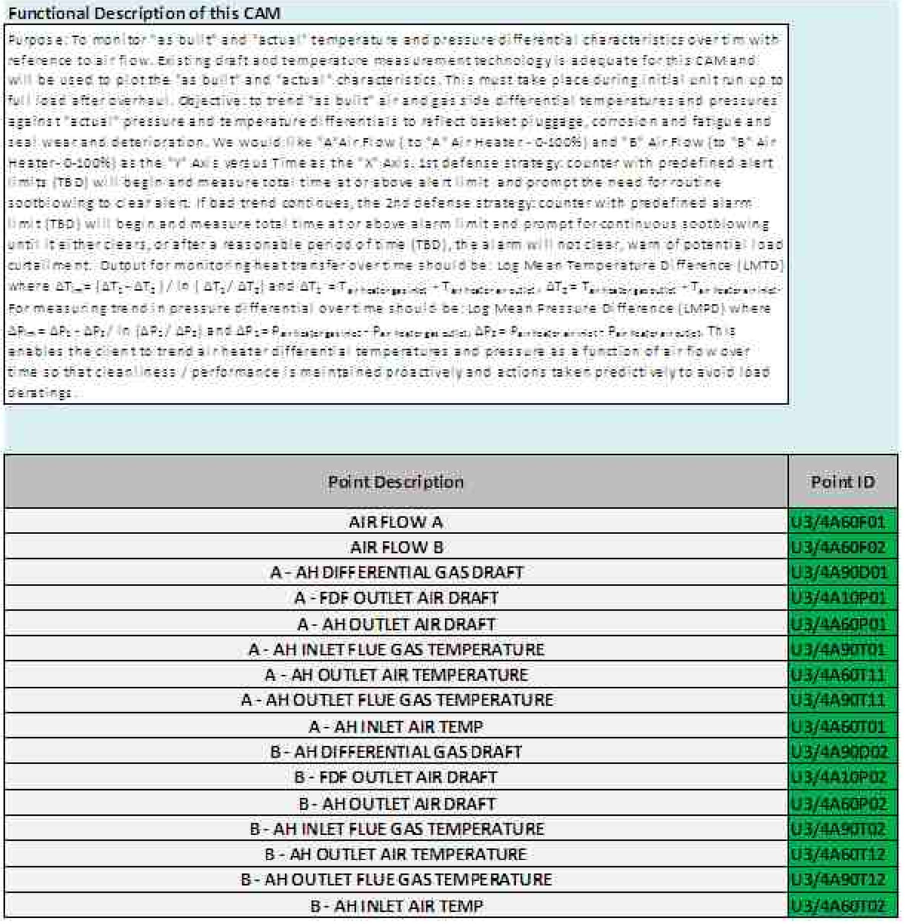
Table 9-4: Identification of Missing Input Parameters



DRAFT LOSS (AIR-SIDE)						
POINT ID	SYSTEM	SUB-SYSTEM	SERVICE DESCRIPTION			
U3/4A60F01	AIR AND GAS	CORRECTION	AIR FLOW A	LOAD CORRECTION		
U3/4A60F02	AIR AND GAS	CORRECTION	AIR FLOW B			
U3/4A90C01	AIR AND GAS	CORRECTION	GAS OUTLET O^2 A			
U3/4A90C02	AIR AND GAS	CORRECTION	GAS OUTLET O^2 B			
U3/4A10P01	AIR AND GAS	FORCED DRAFT FAN	A - FDF OUTLET AIR DRAFT	AIR PREHEATER A ΔP	AIR HEATER A ΔP	A AIR PATH DRAFT LOSS
🟥	AIR AND GAS	AIR PREHEATER	**AIR PREHEATER A OUTLET AIR DRAFT**			
U3/4A60P01	AIR AND GAS	AIR HEATER	A - AH OUTLET AIR DRAFT	SECONDARY AIR A ΔP		
U3/4A70P01	AIR AND GAS	WINDBOX	A - WINDBOX AIR DRAFT			
U3/4A80P01	AIR AND GAS	FURNACE	FURNACE DRAFT			
U3/4A10P02	AIR AND GAS	FORCED DRAFT FAN	B - FDF OUTLET AIR DRAFT	AIR PREHEATER B ΔP	AIR HEATER B ΔP	B AIR PATH DRAFT LOSS
🟥	AIR AND GAS	AIR PREHEATER	AIR PREHEATER B OUTLET AIR DRAFT			
U3/4A60P02	AIR AND GAS	AIR HEATER	B - AH OUTLET AIR DRAFT	SECONDARY AIR B ΔP		
U3/4A70P01	AIR AND GAS	WINDBOX	B - WINDBOX AIR DRAFT			
U3/4A80P01	AIR AND GAS	FURNACE	FURNACE DRAFT			

5. Develop economic justification for procuring, installing and commissioning additional inputs based upon offset value provided by the ability to control the initiation and/ or propagation the identified primary damage mechanisms.

Figure 9-12: Diagnostic Rule for In-Service Condition Monitoring and Diagnostics



Functional Description of this CAM

Purpose: To monitor "as built" and "actual" temperature and pressure differential characteristics over time with reference to air flow. Existing draft and temperature measurement technology is adequate for this CAM and will be used to plot the "as built" and "actual" characteristics. This must take place during initial unit run up to full load after overhaul. Objective: to trend "as built" air and gas side differential temperatures and pressures against "actual" pressure and temperature differentials to reflect basket pluggage, corrosion and fatigue and seal wear and deterioration. We would like "A" Air Flow (to "A" Air Heater - 0-100%) and "B" Air Flow (to "B" Air Heater- 0-100%) as the "Y" Axis versus Time as the "X" Axis. 1st defense strategy: counter with predefined alert limits (TBD) will begin and measure total time at or above alert limit and prompt the need for routine sootblowing to clear alert. If bad trend continues, the 2nd defense strategy: counter with predefined alarm limit (TBD) will begin and measure total time at or above alarm limit and prompt for continuous sootblowing until it either clears, or after a reasonable period of time (TBD), the alarm will not clear, warn of potential load curtailment. Output for monitoring heat transfer over time should be: Log Mean Temperature Difference (LMTD) where $\Delta T_{lm} = (\Delta T_1 - \Delta T_2) / \ln(\Delta T_1 / \Delta T_2)$ and $\Delta T_1 = T_{air\ heater\ gas\ inlet} - T_{air\ heater\ air\ outlet}$, $\Delta T_2 = T_{air\ heater\ gas\ outlet} - T_{air\ heater\ air\ inlet}$. For measuring trend in pressure differential over time should be: Log Mean Pressure Difference (LMPD) where $\Delta P_{lm} = \Delta P_1 - \Delta P_2 / \ln(\Delta P_1 / \Delta P_2)$ and $\Delta P_1 = P_{air\ heater\ gas\ inlet} - P_{air\ heater\ gas\ outlet}$, $\Delta P_2 = P_{air\ heater\ air\ inlet} - P_{air\ heater\ air\ outlet}$. This enables the client to trend air heater differential temperatures and pressure as a function of air flow over time so that cleanliness / performance is maintained proactively and actions taken predictively to avoid load deratings.

Point Description	Point ID
AIR FLOW A	U3/4A60F01
AIR FLOW B	U3/4A60F02
A - AH DIFFERENTIAL GAS DRAFT	U3/4A90D01
A - FDF OUTLET AIR DRAFT	U3/4A10P01
A - AH OUTLET AIR DRAFT	U3/4A60P01
A - AH INLET FLUE GAS TEMPERATURE	U3/4A90T01
A - AH OUTLET AIR TEMPERATURE	U3/4A60T11
A - AH OUTLET FLUE GAS TEMPERATURE	U3/4A90T11
A - AH INLET AIR TEMP	U3/4A60T01
B - AH DIFFERENTIAL GAS DRAFT	U3/4A90D02
B - FDF OUTLET AIR DRAFT	U3/4A10P02
B - AH OUTLET AIR DRAFT	U3/4A60P02
B - AH INLET FLUE GAS TEMPERATURE	U3/4A90T02
B - AH OUTLET AIR TEMPERATURE	U3/4A60T12
B - AH OUTLET FLUE GAS TEMPERATURE	U3/4A90T12
B - AH INLET AIR TEMP	U3/4A60T02

Element Number: 5

Element Classification: Technology

Element Description: Damage and Data Mapping

Element "Best Practice" Attribute(s):

1. Mapping of active and potential incipient damage mechanisms has been performed and vulnerable locations identified
2. Graphic maps of specific boiler locations have been created
3. Equipment Identification, Inspection and Area Coordinate alpha-numeric character strings that link information management tools, the maintenance management system and the in and out-of-service monitoring and inspection plans are in place and utilized
4. Software tools to manage continuous data flow is in place and functional

Figure 9-13: Work Sheet for Initial Screening of Damage Mechanism, Their Status and General Locations

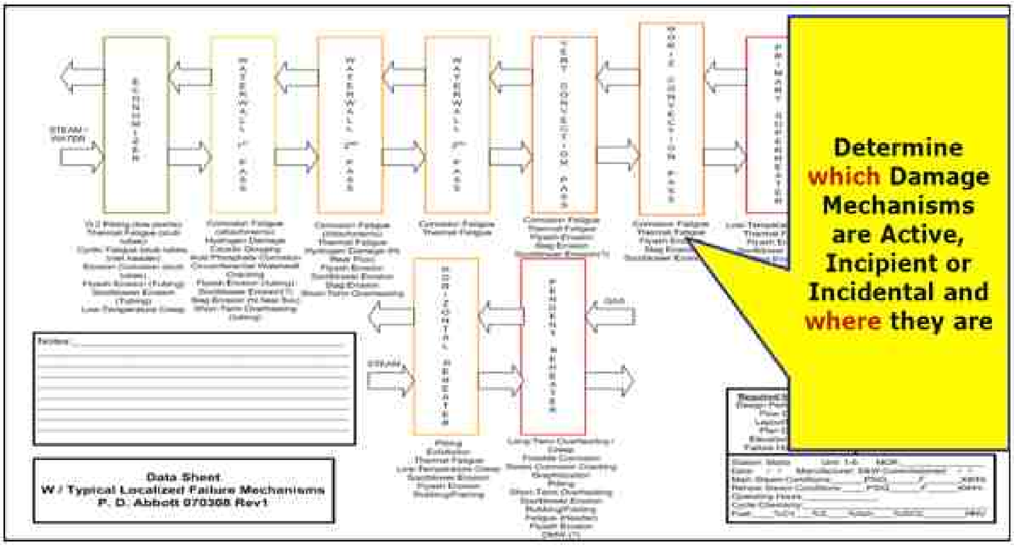
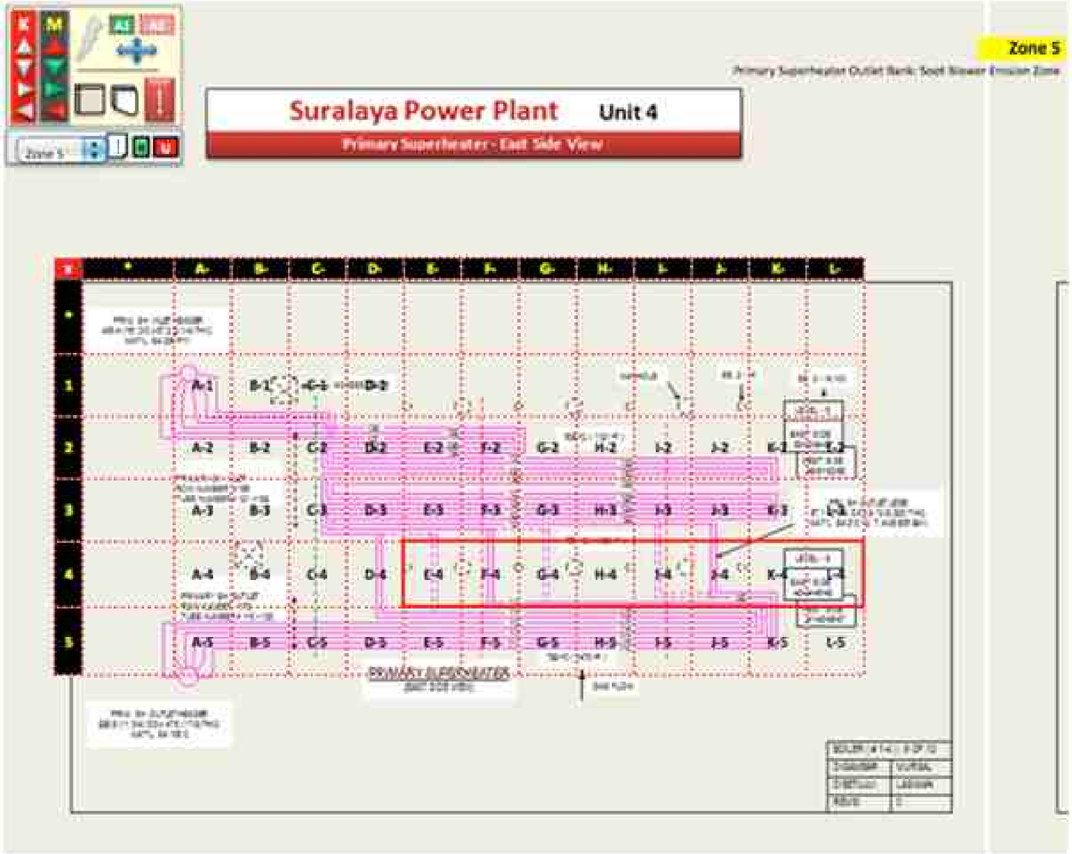


Figure 9-14: Damage Map Shows Zone Addresses and Specific Location to Inspect



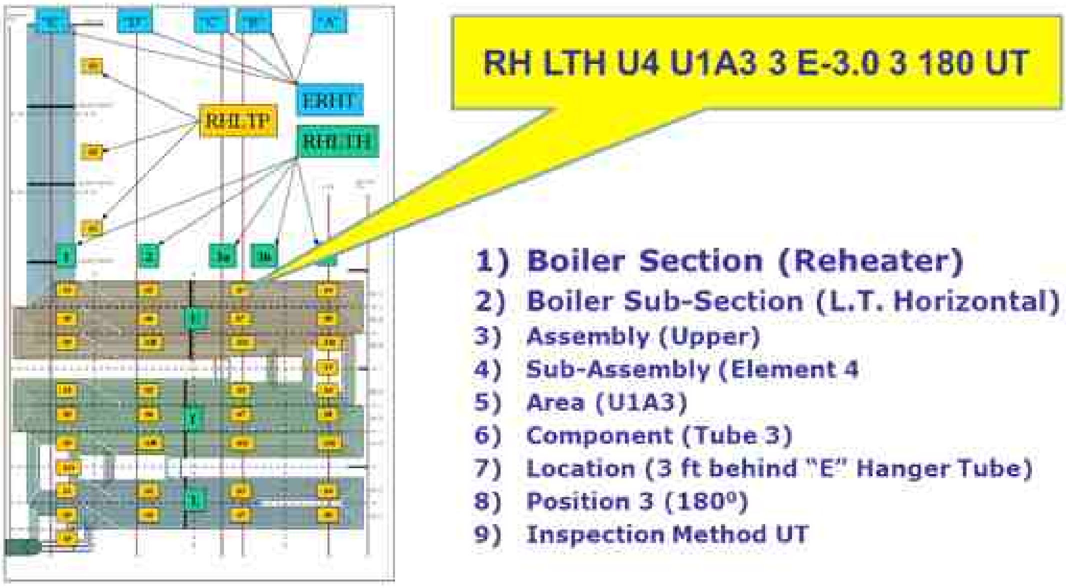
Zone 5

Primary Superheater Outlet Bank: Soot Blower Erosion Zone

Suralaya Power Plant Unit 4

Primary Superheater - East Side View

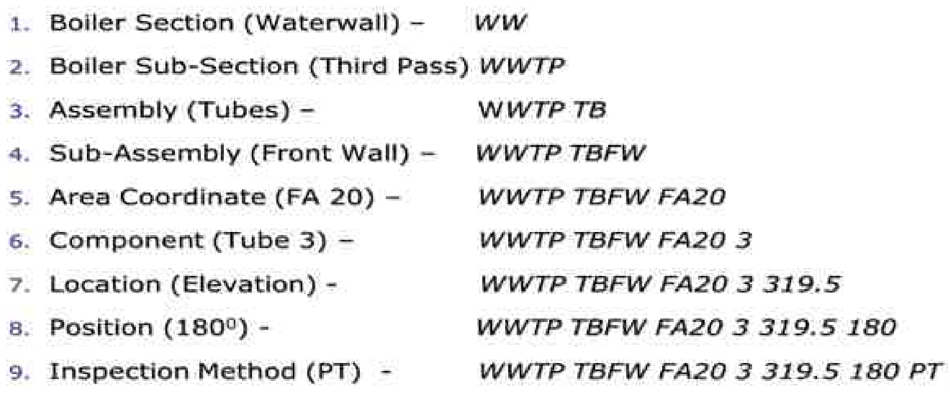
Figure 9-15: Map of Boiler Section with Zone Addresses



RH LTH U4 U1A3 3 E-3.0 3 180 UT

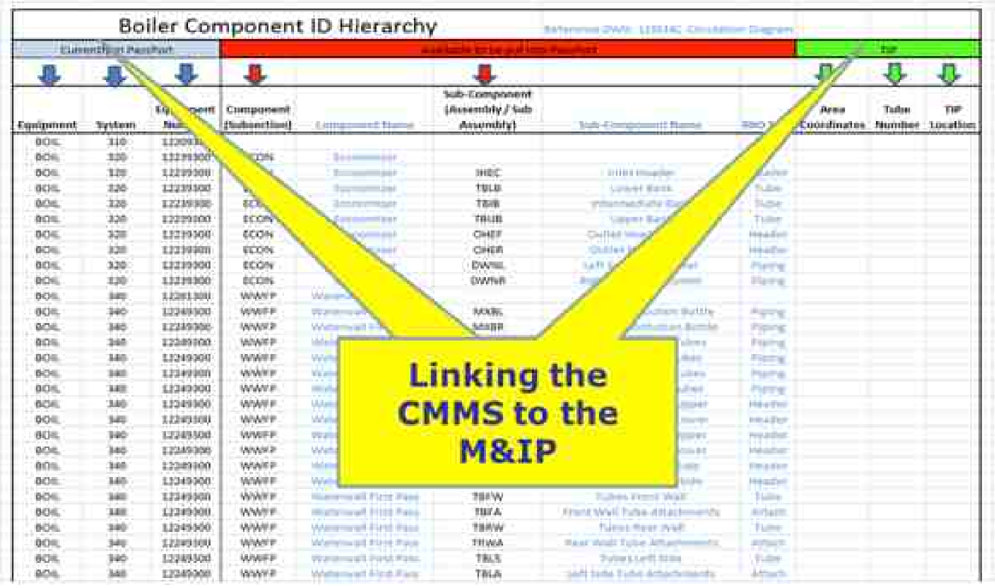
1) **Boiler Section (Reheater)**
2) **Boiler Sub-Section (L.T. Horizontal)**
3) **Assembly (Upper)**
4) **Sub-Assembly (Element 4**
5) **Area (U1A3)**
6) **Component (Tube 3)**
7) **Location (3 ft behind "E" Hanger Tube)**
8) **Position 3 (180⁰)**
9) **Inspection Method UT**

Figure 9-16: Alpha-Numeric String Utilized to Link Inspections



1. Boiler Section (Waterwall) – *WW*
2. Boiler Sub-Section (Third Pass) *WWTP*
3. Assembly (Tubes) – *WWTP TB*
4. Sub-Assembly (Front Wall) – *WWTP TBFW*
5. Area Coordinate (FA 20) – *WWTP TBFW FA20*
6. Component (Tube 3) – *WWTP TBFW FA20 3*
7. Location (Elevation) - *WWTP TBFW FA20 3 319.5*
8. Position (180⁰) - *WWTP TBFW FA20 3 319.5 180*
9. Inspection Method (PT) - *WWTP TBFW FA20 3 319.5 180 PT*

Figure 9-17: Equipment Identification Numbering (EIN) String



Equipment Identification Numbering (EIN) string that takes the hierarchy down to sub-component level of detail to link sub-component historical data in the maintenance management system to the monitoring and inspection plans.

Element Number: 6

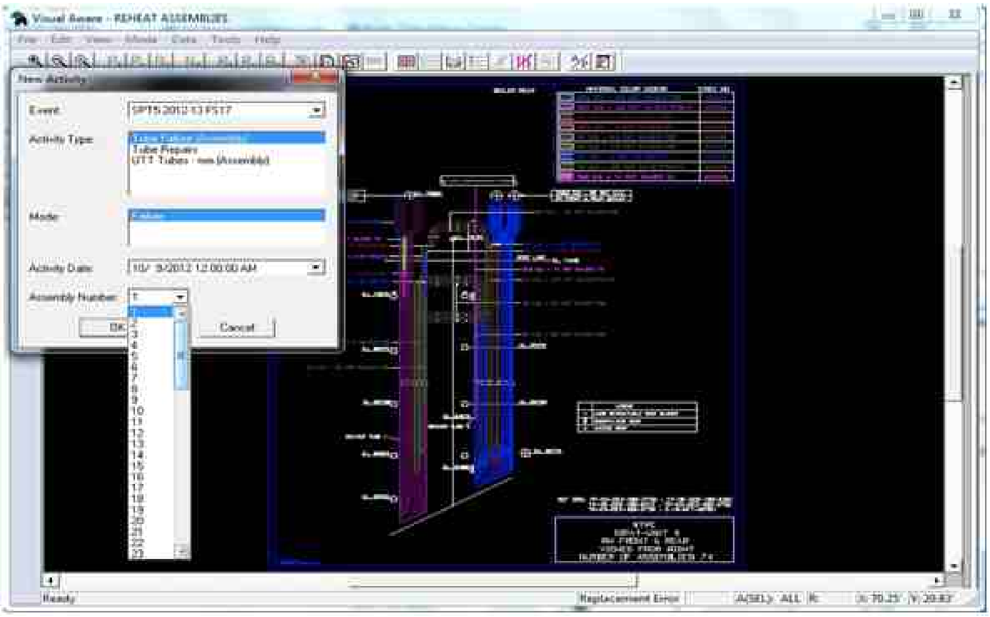
Element Classification: Technology

Element Description: Monitoring & Diagnostic Tools

Element "Best Practice" Attribute(s):

1. All identified non-destructive examination resources are in place and certified
2. All identified destructive examination resources are in place and certified
3. Software tools to manage periodic destructive and non-destructive examination and repair data is in place and functional

Figure 9-18: **Software Tool Used to Manage Periodic Destructive and Non-Destructive Examination and Repair Data (In this case, the tool is ATI's Aware)**



Event: SPTS 2012-13 FS17

Activity Type: Tube Repairs

Activity Date: 10/ 9/2012 12:00:00 AM

Assembly Number: 1

Figure 9-19: **Software Tools to Manage Boiler Data Continuously (In this case, the tool is P&RO Solutions ProView)**

	PLTU Unit 1	PLTU Unit 2	PLTU Unit 3	PLTU Unit 4
Reheater	Normal	Normal	Normal	[illegible]
Primary Superheater	Normal	Normal	Normal	Normal
Final Superheater	Normal	Normal	Normal	Normal
Secondary Superheater	Normal	Normal	Normal	Normal
Steam Drum	Normal	Normal	Normal	Normal
Heat Recovery Area	Normal	Normal	Normal	Normal
Economizer	Normal	Normal	Normal	Normal
Boiler Tube Wall	Normal	Normal	Normal	Normal
Air Heater	Marginal	Normal	Normal	Normal

Element Number: 7

Element Classification: Technology

Element Description: Information Management

Element "Best Practice" Attribute(s):

1. A Periodic Information Management tool is in place, functional and is used by the System Owner to fully support the Monitoring and Inspection Plan (Unit Out-of-Service) and process
2. A Continuous Information Management tool is in place, functional and is used by the System Owner to fully support Monitoring and Diagnostic Plan (Unit In-Service) and process

Element Number: 8

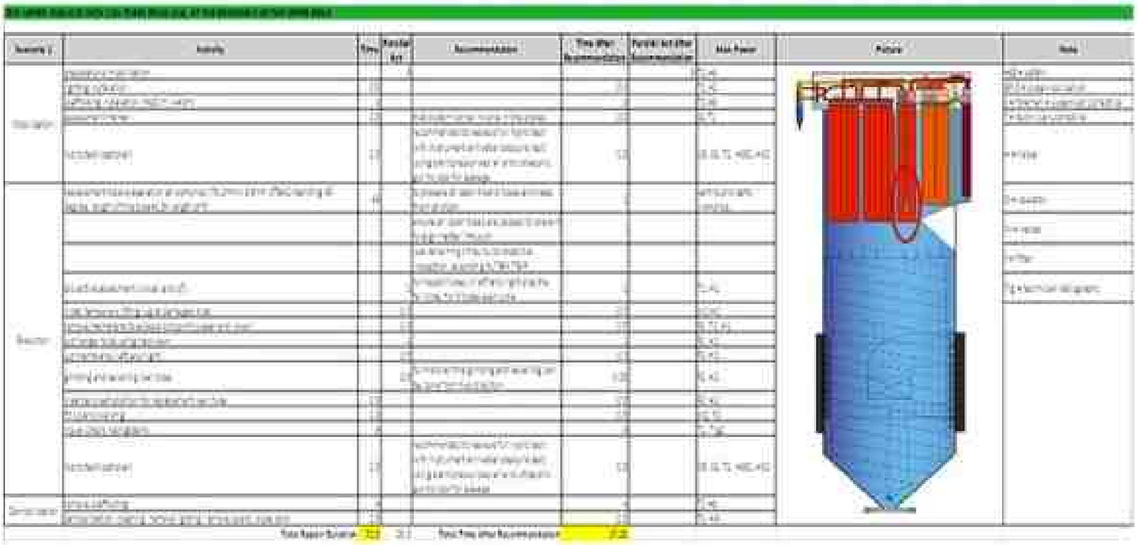
Element Classification: Process

Element Description: Risk Management

Element "Best Practice" Attribute(s):

1. Knowledge Capture through task baselines yield starting values for Time To Inspect (TTI) and Time To Repair (TTR) and Inspection Prioritization Indexes (IPI) – all are used for estimating consequences of events and improving workforce efficiency

Figure 9-20: Knowledge Capture Through Task Baselines Yield Starting Values for Time to Inspect (TTI) And Time to Repair (TTR)



2. Work closeout process in place and functional to drive baselines to actual benchmarks and to enable workforce productivity measures and time averaging for Mean Time To Inspect (MTTI), Mean Time To Repair (MTTR) and refinement of Inspection Prioritization Index (IPI)

3. Root-cause analysis process in place and functional to drive accurate mitigating action and improved effectiveness
4. A process utilized by the System Owner to drive risk evaluations (damage probabilities and consequences) for prioritizing inspection and/or repair work activities and to feed performance measurement in place and functional

Figure 9-21: TBM's Inspection Prioritization Index and Damage Status drive Inspection Frequencies

IPI and Status	Recommended Frequency
➢ A-Active:	Opportunity, 100% Sampling to Establish Baseline, Second to Determine Wastage Rate and to Establish Subsequent Inspection Frequency
➢ B-Active:	18 Months, 100% Sampling to Establish Baseline, Second to Determine Wastage Rate and to Establish Subsequent Inspection Frequency
➢ C-Active:	36 Months, 100% Sampling to Establish Baseline, Second to Determine Wastage Rate and to Establish Subsequent Inspection Frequency
➢ D-Active:	If Discovered, Confirm Damage Mechanism and Analyze Root Cause for Immediate Resolution
➢ Unspecified-Active:	100% Sampling Per Standard Procedure

Element Number: 9

Element Classification: Process

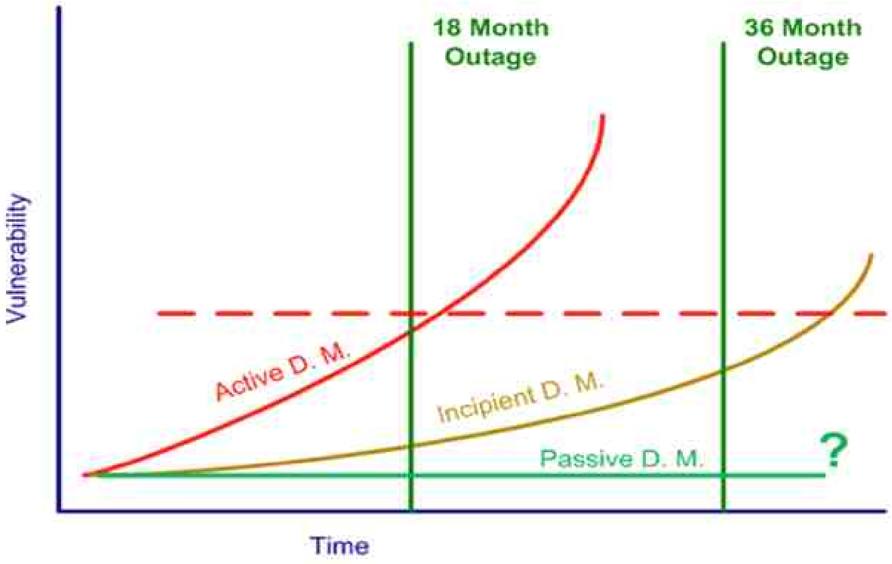
Element Description: Short-Notice Outage Optimization

Element "Best Practice" Attribute(s):

1. Unique Plans and Strategies are in place and based on Unit Dispatch Requirements
   - Very Urgent return to service - A plan to address Inspections and / or Repairs in High Priority High Risk areas
   - Less Urgent return to service – A plan to address Due or Overdue Inspections in High Priority areas
2. Inspection and Repair Work Orders, Work Packages / Work Instruction's with Benchmark Duration's in place to support the boilers' Monitoring & Inspection Plan
3. Integrated Work Package/Work Instruction's that include Inter and Intra-Departmental Coordination Requirements to support the activity
4. The System Owner manages work scope

5. A Work Management Team to Support the System Owner in the TBM Process
   - Planners to adjust inspection and/or repair scopes per System Owner's request
   - Schedulers coordinate and schedule work to fit within outage time constraints

Figure 9-22: A Strategy Diagram for Extending Boiler Pressure Part Outage Frequencies through Managing Active Damage Propagation and Incipient Damage Initiation



Element Number: 10

Element Classification: Process

Element Description: Knowledge Capture (Work Process)

Element "Best Practice" Attribute(s):

1. Criticality values derived yielding consequences for prioritizing defense against boiler tube failures in specific boiler locations

2. Risk parameters (total repair/inspection time (TTR/I), cost and availability consequences calculated for each location and each tube failure scenario

Figure 9-23: Scenario Spreadsheet that Identifies Risk Parameters

- This scenario spreadsheet identifies risk parameters e.g. (total repair/inspection time (TTR/I). Also, cost and availability consequences are provided for each location of each tube failure modeled using this quick easy TBM method scenario. Note: total job duration (Yellow)

Element Number: 11

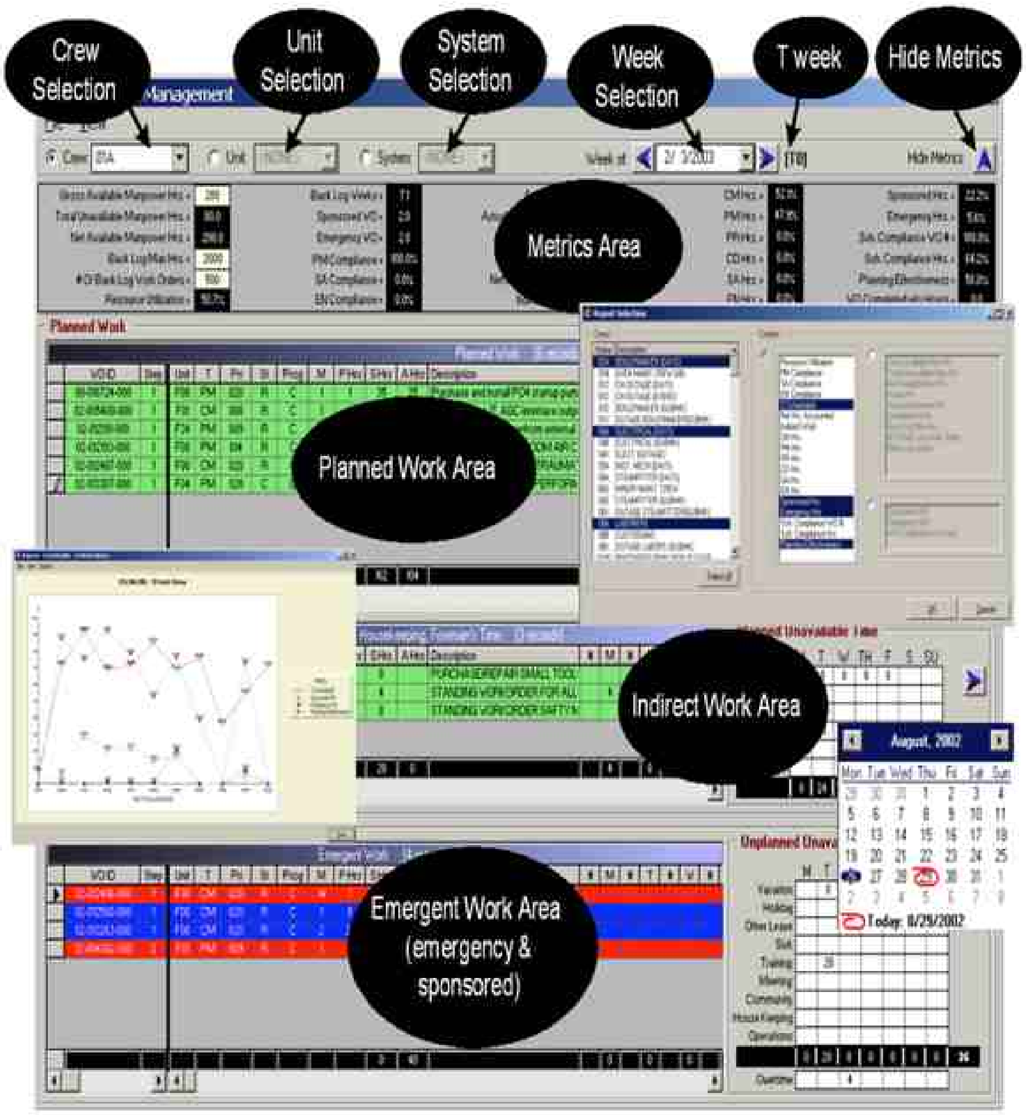
Element Classification: Process

Element Description: Work Management

Element "Best Practice" Attribute(s):

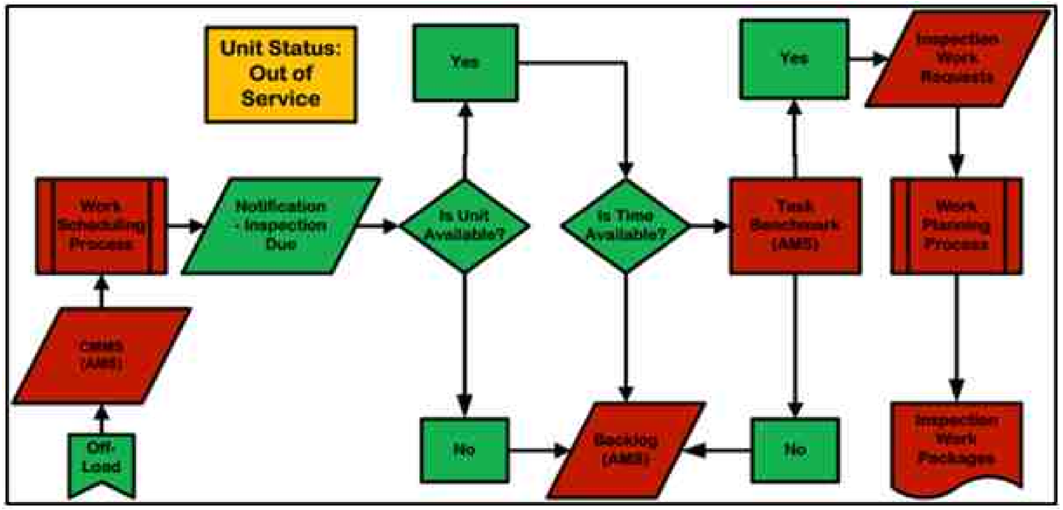
1. Planning and Scheduling is accomplished based on a four-week rolling schedule

Figure 9-24: Work Management Software



2. Risk-Based Prioritization is used by the System Owner to prioritize inspection and/or repair tasks per Monitoring and Inspection Plan
3. Inspection and/or Repair Outage Work Backlog is managed by the System Owner, scheduled through the maintenance management system based on the Monitoring and Inspection Plan

Figure 9-25: Outage Backlog Management System - Owner Decision-Making Process



4. Forced/Maintenance Outage Plans are Kept ready to work by scheduler and are sorted by task priority and duration based on Monitoring and Inspection Plan
5. Planned Outage Plans are kept current by work scheduler with scope influenced by work accomplished during maintenance and forced outages
6. Detailed Work History in Maintenance Management System

Element Number: 12

Element Classification: Process

Element Description: Inherent Condition Analysis

Element "Best Practice" Attribute(s):

1. Damage mechanisms influenced by the inherent consequences of boiler operation have been determined and included in the Monitoring and Inspection Plans
    - Physical influence of time at temperature
    - Physical influence of thermal and mechanical cycles
    - Chemical influence of abnormal water chemistry
    - Chemical and Mechanical influence of post-combustion ash impurities.

Example: Mechanical influence of post-combustion ash impurities

- TDM = Fly Ash Erosion
    - Erosion index (Impingement or cutting wear causing reduction in tube wall thickness – fly ash erosion)
    - From analysis of silica and quartz content in ash

Erosion Propensity	SiO_2 Content (wt. %)	Erosion Index
Low	<40	<0.02
Medium	40 -50	0.02 -0.08
Medium -High	50 -60	0.04 -0.28

- From particle size analysis of flame-heated ash; burned ash sample of typical coal, size-fractioned and analyzed for quartz contento
  - o $Ia = \{X_1(L_1 + 0.4) + X_2(0.5L_2 + 0.2)\}I_{1q}$
    - Ia = Abrasive index of ash
    - X_1 and X_2 = **weight fraction of >45 µm and 5-45 µm quartz size cuts**
    - I_{1q} = **>45 µm-size quartz particles**
  - o This formula accounts for abrasion due to silica particles and quartz particles where $I_{1g} = 0.4 I_{1q}$ (Raask, Sage, Bratchikov 1969) (Stringer 1981)

Erosion Propensity	Particle Diameter (m)	Relative Erosion Index	Erosion Index
Low	<5	0	<0.02
Medium	5-45	0.5 I_{1a}	0.02 -0.08
Medium-High	>45	I_{1a}	0.04 -0.28

Example: Chemical influence of post-combustion ash impurities

- TDM = Acid Dewpoint Corrosion
- Corrosion, Maximum Acid Deposition Rate – acid dewpoint corrosion (economizer, air heater, flue gas outlet section)
  - o From acidity characteristics of flue gas assuming 4 percent excess oxygen. Based upon sulfur (%) content of coal, CaO (%) in ash, SO_3 (ppm) in flue gas, dewpoint temperature (K)

Acid Deposition Rate (mg $/m^2$)	**Coal Type**	**Sulfur in Coal (%)**	**CaO in Ash (%)**	**SO_3 flue gas (ppm)**	**Dewpoint Temperature (K)**
-10 (High)	High sulfur, low calcium	>2.5	2-5	10-25	400-410
2.5-5 (Medium)	Medium sulfur, low calcium	1-2.5	2-5	5-10	295-400
-2.5 (Low)	Medium sulfur, medium calcium	1-2.5	5-10	1-5	285-295
<1 (non - acidic)	Low sulfur, high calcium	<1	>10	<1	<28.5

Element Number: 13

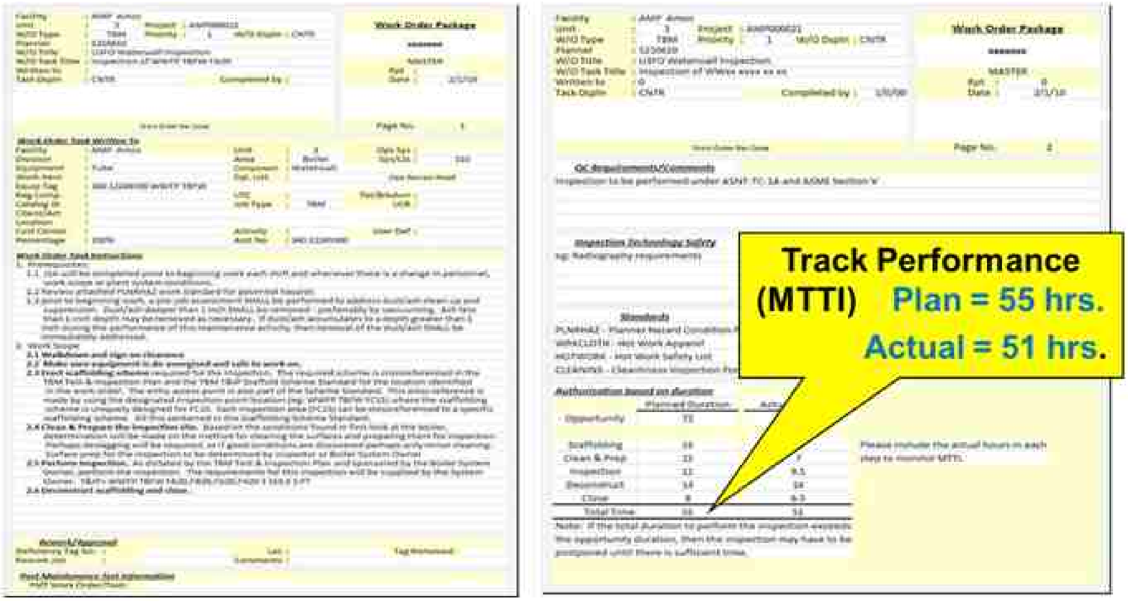
Element Classification: People

Element Description: Performance Measures and Metrics

Element "Best Practice" Attribute(s):

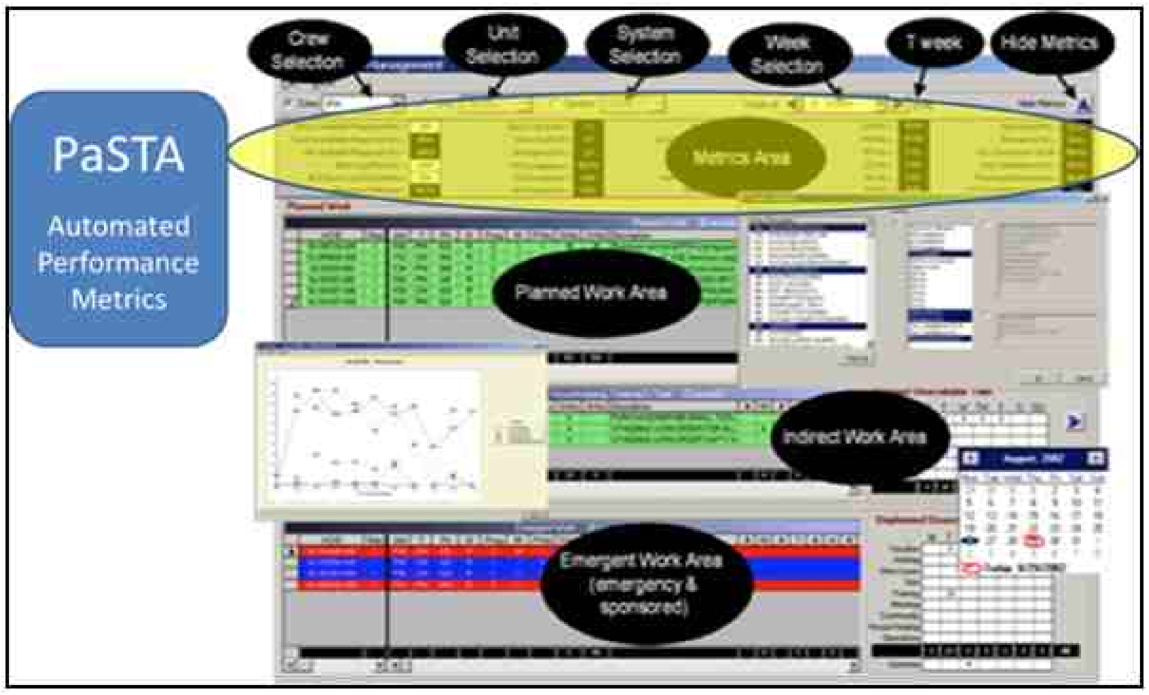
1. Accurate documentation of efficiency e.g. Time to Repair and Time to Inspect and trending Mean Values of both (MTTR/MTTI) by System Owner

Figure 9-26: Accurate Documentation of Efficiency e.g. Time to Repair and Time to Inspect



2. Accurate documentation of reliability e.g. Time Between Failures for each section of the boiler and trending Mean Values of each (MTBF) by System Owner
3. Accurate trending of non-fuel O&M e.g. Cost/MW for each boiler cost center
4. Accurate trending of capital investment e.g. Cost/MWh for each boiler cost center

Figure 9-27: Software Tool to Automate Generation of Performance Metrics



Element Number: 14

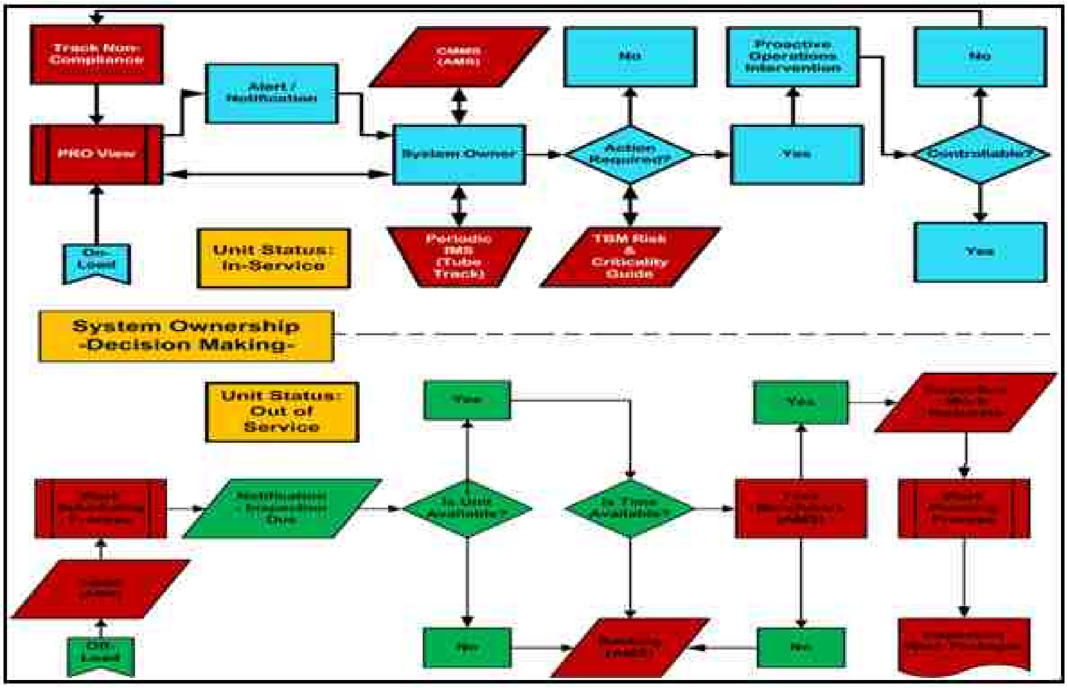
Element Classification: People

Element Description: Accountability

Element "Best Practice" Attribute(s):

1. A System Owner responsible for the reliability and integrity of the boiler pressure parts (System Owner)
2. The System Owner's personal performance measures are tied to the reliability and integrity of the boiler pressure parts (Measures and Metrics)

Figure 9-28: TBM System Owner's In- and Out-of-Service Decision-Making Processes



Element Number: 15

Element Classification: People

Element Description: Training

Element "Best Practice" Attribute(s):

Basic

1. Familiarity with applicable safety standards
2. Familiarity with engineering economics principals
3. Familiarity with steam generation design and construction

Developmental

1. Familiarity with Non-Destructive Examination (NDE) Methods and Certification e.g. American Society for Non-Destructive Testing (ASNT)-TC-1A or equivalent))
2. Familiarity with Design and Repair Codes e.g. American Society of Mechanical Engineers (ASME/Indian Boiler Standard) Code Section 1 and Section 9)
3. Familiarity with NDE and Material Quality Assurance/Quality Control (QA/QC) Principles and Standards e.g. American Society Testing and Materials now ASTM International / Indian Boiler Standard

Advanced

1. Familiarity with Process Optimization Principles e.g. Plant Reliability Optimization (PRO)
    - Reliability-Centered Maintenance (RCM)/Failure Modes and Effects Criticality Analysis (FMECA) for Building a Reliability Basis
    - Work Management for Executing and Controlling the Reliability Basis
    - Condition Monitoring and Predictive Maintenance
    - Continuous Improvement and Proactive Maintenance
    - Reliability Risk Management

Conclusion

There are several benefits from having a System Owner and support team in place and from precise implementation of Targeted Boiler Management. Some of the benefits are as follows:

- Minimize or eliminate boiler tube and header failure cost effectively
- Operations is able to shorten or off-set off-normal events that cause tube / header damage (Proactivity)
- An ideal pressure part "System Owner" management model exists for other to emulate
- Tube leaks will become less frequent or cease to occur(∞ MTBF)
- Boiler pressure part maintenance will not drive planned outage frequency and duration (If outage inspection backlog is managed)
- Realization of material design life
- More accurate pressure part budget forecasting
- Optimized forced outage planning of pressure part work
- Effective and efficient utilization of resources
- More extensive use of computer capabilities (CMMS, Information Management Systems, Data Historian and Third-Party condition monitoring software)

Implementation of the previous can make the management of boiler pressure parts easy.

Figure 9-29: Managing Boiler Pressure Parts is Easy!

9.3 COAL QUALITY CONSIDERATIONS

This section focuses on damage mechanisms that attack the gas-side of tubing and headers from impurities in the fuel and fuel combustion. Each damage mechanism, its failure modes and damage causes are explained. "Best Practice" damage defenses using the proactive and predictive Targeted Boiler Management Approach to help keep damage from initiating or propagating are detailed. Coal quality damage mechanisms include:

1. Fly ash Erosion
2. Sootblower Erosion
3. Fireside Corrosion
4. Acid Dewpoint Corrosion
5. Stress Corrosion Cracking (Gas-Side)

9.3.1 Fly Ash Erosion

Background

Fly ash erosion accelerates tube wastage by direct material removal and by removal of protective fireside oxide of the base material. This increases the oxidation rate. After coal is combusted and the boiler's effective area is reduced, fly ash with high local velocity removes the tube materials protective oxide scale resulting in accelerated wall thinning. It however depends on the extent of ash loading, particle size and erosive impurities (quartz and pyrites), and incidental impact of OD tube metal facing the gas flow.

Figure 9-30: Fly Ash Erosion

Table 9-5: Erosion Characteristics are Determined from Analysis of Silica and Quartz Content in Ash

Erosion Propensity	SiO_2 Content (wt. %)	Erosion Index
Low	<40	<0.02
Medium	40-50	0.02-0.08
Medium-High	50-60	0.04-0.28

Table 9-6: Erosion Characteristics Based on Silica Particles and Quartz Particle Sizing

Erosion Propensity	Particle Diameter (m)	Relative Erosion Index	Erosion Index
Low	<5	0	<0.02
Medium	5-45	0.5l 1a	0.02-0.08
Medium-High	>45	l1a	0.04-0.28

With constant primary (hoop) stress and tube wall thinning, a thin-wall ductile tube rupture occurs.

The root cause of fly ash erosion is excessive local (non-uniform or turbulent) gas flows which entrain large volumes of erosive fly ash particles and directs them onto the tube surface.

Some potential evidence prior to significant tube damage occurring can be as follows:

1. Burnishing or polishing of tube outside surfaces facing the gas flow.
2. Very localized wear and wastage flats.
3. Fresh rust on tubes after unit washing adjacent to blockage of boiler gas passages.
4. Arbitrary addition of deflection baffles without CAVT modeling.
5. Change to a coal with higher ash content and / or abrasion propensity.
6. Operating above MCR with excessive and / or unbalanced air and gas flow.
7. Pluggage of gas paths resulting in higher localized velocities.

"Best Practice" for Damage Defense

Cold Air Velocity Testing (CAVT) is a "best practice" for initiating defenses that minimize potential damage resulting from flyash erosion. Once modifications are made, CAVT should again be employed and damage patterns reevaluated to optimize those defenses. In addition, employ Visual Inspections (VT) to locate, ultrasonic thickness measurements (UT) to quantify wall wastage and the two in combination to characterize the distribution and extent of wear near the boiler side and rear walls; nearest to draft source, near economizer banks, near gas-direction changes, near plugged or fouled passages; and where baffles had been installed previously. Look for 1) burnishing or polishing of OD tube surfaces facing gas flow 2) localized wear and wastage, and 3) Fresh rust on tubes after unit washing adjacent to bridged or fouled gas passages.

9.3.2 Sootblower Erosion

Background

Sootblower erosion causes accelerated OD tube wastage by direct material removal and removal of the fireside oxide that increases the oxidation rate. When the sootblower is operated, supply air or steam entrains and accelerates abrasive ash particles and possibly moisture or condensate from wet air or low enthalpy steam. This causes local tube OD erosion on impacted tube surfaces that result in thinned tube walls. Eventually the tube wall yields to constant primary (hoop) stresses and a thin-edged, longitudinal "fish mouth" failure occurs. Root causes of sootblower erosion can be improper sootblower operation and/or maintenance, insufficient superheat in sootblower supply steam or moisture removal in air supply and improper sootblower alignment.

Evidence or circumstances that occur prior to tube damage occurring:

1. Poor or non-existent sootblower maintenance
2. Burnishing or polishing of tube outside surfaces

3. Very localized wear and wastage flats.
4. Fresh rust on tubes after unit washing

"Best Practice" for Damage Defense

"Intelligent" sootblowing is "Best Practice" with sootblowers in service. Maintenance is the "best practice" damage defense against sootblower erosion out of service. Note that root-causes of sootblower erosion and boiler slagging, bridging and fouling are distinct and different. They should not be confused. Frequent sootblower alignment and pressure checks are recommended while the unit is on-line. When there are opportunities, technicians should be dispatched and Visually Inspect (VT) waterwalls adjacent to wall de-slaggers and superheater and reheater tubes in the path and within blowing radius of retractable sootblowers. Sootblower erosion is manifested the same as other erosion processes except damage is local and not widespread. It appears as tube wall thinning caused by external tube wastage. The erosion pattern will be angled to the tubes from the direction of the blow. As erosion becomes more severe, flat spots will form. Few or no ash deposits are evident. Horizontal, tight pitched thermal fatigue cracks on tube surfaces are possible if adequate moisture is present in the blowing medium (quenching).

Figure 9-31: Soot Blower Erosion

9.3.3 Fireside Corrosion

Background

Fireside corrosion has reached epic proportions with the emphasis placed on NOx reduction in the U.S. Fireside corrosion is from the formation of pyro-sulfates, alkali-iron tri-sulfates in the presence of a low O_2 reducing atmosphere during fuel combustion. Mechanical removal of the tubes' protective oxide exposes the base material. The unprotected tube surface is attacked by acidic sulfates in the slag that concentrate in sub-stoichiometric combustion environments. Tube metal temperature plays an important role in the rate of fireside and waterside under-deposit corrosion. Sulfate concentrations on the outer surface of the tube and excess internal tube deposits raise the mean tube metal temperature and accelerate the rate of both ID and OD tube corrosion. The concentrated sulfates sets the rate of OD corrosion and tube wall thinning progresses until the tube yields to primary (hoop) stresses and thin-edged, longitudinal "fish mouth" rupture occurs.

Figure 9-32: Fireside Corrosion

The root-cause(s) of Fireside Corrosion are local "reducing" environment and the occurrence and deposition of pyro-sulfates, burning coal with unusually aggressive ash/slag (Cyclone Units), direct impingement of carbonaceous particles removing the tubes protective oxide and non-uniform mixing of fuel and air in the flame.

Evidence or circumstances that occur prior to tube damage occurring:

1. Flame impingement due to burner change.
2. Burner misalignment leading to excessive tube deposits.

3. Problems controlling levels of feedwater corrosion products e.g. operating ranges for pH, cation conductivity or dissolved oxygen consistently outside recommended ranges, and excessive use of oxygen scavengers.
4. Heat flux change that cause deposits from a change to higher calorific value coal, dual firing with natural gas or conversion to oil or gas.
5. Implementing low excess air strategies for NOx control.

"Best Practice" for Damage Defense

To combat Fireside Corrosion, Ultrasonic Thickness measurement (UT) for wall thinning and trending data to quantify wastage rates is very popular. This approach has been complicated, to some degree, by weld overlay of tubing to protect it. Any voids between the overlay and the tube wall can result in erroneous readings so care should be exercised. There is potential for a ~120 degree arc of damage; also, hard deposits are typical on outside tube surfaces so time for surface preparation prior to inspection should be taken into account. Tube wastage is probably widespread over a number of tubes with maximum wastage on tube crown facing the flame. Emphasis should be placed on finding areas with most severe wastage rather than overall average wastage rates. These areas are typically areas with locally sub-stoichiometric combustion environments like side and rear walls near burners and high heat-flux areas; under upper deflection arch and on ash hopper slopes.

9.3.4 Acid Dewpoint Corrosion

Background

Acid dewpoint corrosion is primarily a result of the oxidation of molecules of SO_2 into SO_3 just after combustion, which combines with moisture in the flue gas to form much weak sulfurous and some strong sulfuric acid. The electrolytic sulfuric acid condenses on tube surfaces with metal temperatures below that of the gases dewpoint temperature, typically on the exposed economizer and convective back pass tube surfaces. Electrolysis between the acid and the moisture results trans-granular corrosion, pitting on the tube surfaces and wall thinning. As corrosion progresses the thin tube wall yields to primary (hoop) stress in a thin-edged ductile failure.

Figure 9-33: Acid Dewpoint Corrosion

Root-causes of failure can be economizer/back pass tube temperatures operating in cold climates, without air preheater coils and below the acid dew point of the flue gas, high acid dewpoint temperature caused by fuel and/or operating choices, local air in-leakage and presence of sulfurous ash deposits on tube surfaces.

Evidence or circumstances that occur prior to tube damage occurring:

1. Unit operating with a number of feedwater heaters out of service.
2. Change to a more corrosive coal, particularly one high in sulfur content.
3. Running with high excess oxygen levels.
4. High surface moisture content of fuel.
5. Steam coils out of service or improperly operated.

"Best Practice" for Damage Defense

Be aware of precursors listed above when the unit is in-service. When out of service, visually inspect (VT) economizer and convective back-pass for signs of corrosion. If identified, perform Ultrasonic Thickness (UT) measures to survey extent of wall thinning (constraints on accessibility may limit ability to UT until more time becomes available).

Fireside oxide scale will be thin or missing in affected regions. The corroded surface of the tube, after removal of fireside deposits, will have a gouged or "orange peel" appearance. Metal attack will be confined to surfaces that were covered with the sulfurous ash deposits. The attack often produces well-defined regions of metal loss and leaves islands of metal relatively intact. Fireside deposits will contain sulfur and a white layer of iron sulfate may be present at the tube or deposit interface.

9.3.5 Coal Quality Driven Stress Corrosion Cracking

Background

Stress Corrosion Cracking (SCC) occurs with the combined action of a susceptible material (Primarily Austenitic Stainless Steel (SA-213 321H, SA-213 347H, SA-313 304H) tubing, excessive applied or residual tensile stress and excess deposits and a low pH environment. Cracks can be trans- or inter-granular, are O.D.- initiated and grow in a susceptible material when simultaneously exposed to tensile stress and an adverse chemical environment. Cracks propagate until tube material yields to primary (hoop) stresses and a thick-edged fracture (sometimes manifested as pinhole) occurs.

Figure 9-34: Stress Corrosion Cracking

The root-cause of Stress Corrosion Cracking requires three aspects together: interaction with chlorine gasses, excessive tensile stress and a susceptible, sensitized material. However, an initiating defect such as a scratch, pit or weakness in the protective oxide allows for initial corrosive attack.

Evidence or circumstances that occur prior to tube damage occurring:

- Burning coal with high chlorine and/or sodium content.

"Best Practice" for Damage Defense

Be constantly aware of the precursor listed above while the unit is in-service. Target inspections based on events that occur and suspected locations. Dye Penetrant Test (PT) to detect surface cracks on tube samples, or Eddy Current Testing (ECT) to detect sub-surface cracks on austenitic stainless and ferritic alloy materials, Perform Fluorescent Magnetic Particle (MT) testing to detect sub-surface cracking on ferritic materials. Cracking is trans-granular and inter-granular, usually with significant branching. Crack initiation is most common on the tube OD.

Failure locations are typical gas-touched austenitic assemblies. High stress locations in these locations are particularly susceptible such as bends, welds, tube attachments, supports or spacers, especially accompanied with a change in material thickness. Note: outbreaks of Stress Corrosion Cracking caused by chemical exposure tend to be widespread, not local.

Failures are thick-edged and brittle. Cracks can be oriented circumferential or longitudinal as they will form perpendicular to the dominant source of stress. Stress Corrosion Cracking must be differentiated from Long-Term Overheating/Creep Fatigue for remedial reasons. Unlike Long-Term Overheating/Creep Fatigue, Stress Corrosion Cracking will not show the presence of creep voids at grain boundaries. Instead, Stress Corrosion Cracking damage will typically result in grains that fall out!

9.4 WATER QUALITY CONSIDERATIONS

This section focuses on damage mechanisms that attack the water/steam-side of tubing and headers from impurities and parameters out of acceptable limits. Each damage mechanism, its failure modes, and damage causes are explained. "Best Practice" damage defenses using the proactive and predictive Targeted Boiler Management Approach to help keep damage from initiating or propagating are detailed. Water Quality damage mechanisms include:

1. Steam Side Stress Corrosion Cracking (Steam-Side Attack)
2. Flow-Accelerated Corrosion
3. Corrosion Fatigue
4. Supercritical Waterwall Cracking
5. Hydrogen Damage

9.4.1 Water Quality Driven Stress Corrosion Cracking

Background

Refer to Section 9.3.5.

Evidence or circumstances that occur prior to tube damage occurring:

1. Carryover of volatile sulfates and other chemicals from the boiler e.g. NaOH for units on caustic treatment, or excess Na, SO4 and/or Chlorides exceed steam limits.
2. Contaminations in the SH/RH, particularly by chlorides.
3. Contamination during chemical cleaning of superheater or reheater caused by breakdown of inhibitors or improper flushing.
4. Condenser leaks leading to cooling water contaminant carryover in attemperator spray water.
5. Drum carryover testing indicates low steam quality and high mechanical carryover.

"Best Practice" for Damage Defense

Failure locations are typical in low bends on vertical austenitic pendant assemblies and low points in straight austenitic tubing where condensate can form during shutdown. These locations are exposed to the highest concentrations of contaminants during start-up when water solutions left in are boiled out of the superheater and reheater. High stress locations in these locations are particularly susceptible such as bends, welds, tube attachments, supports or spacers, especially accompanied with a change in material thickness. Note: outbreaks of Stress Corrosion Cracking caused by chemical carryover tend to be widespread, not local.

9.4.2 Flow Accelerated Corrosion

Background

Flow Accelerated Corrosion or Erosion/Corrosion is caused by a combination of: dissolution or removal of a tube or pipe's ID protective oxide in the presence of an aggressive chemical environment. Chemical dissolution of ID oxide is most aggressive at water temperatures of 130-140°C with reducing water conditions and flow accelerated removal at higher water temperatures up to approximately 280°C. This means that most instances of damage occur in feedwater or economizer sections.

Figure 9-35: Flow Accelerated Corrosion

The pressure part System Owner is most interested in damage that can occur in the economizer, typically at or just downstream of the inlet header outlet stub tubes. (Specifics depend on design temperature and pressure). Here, local flow into the tubes, water with very low dissolved oxygen results in removal of the protective oxide faster than it can form, corrosive attack of the inside tube surfaces, tube wall thinning and eventually the tube will yield to primary (hoop) stress causing ID-initiated thin-edged ductile rupture.

The root causes of Flow Accelerated Corrosion are twofold depending on the water temperature; corrosion caused by reducing feedwater conditions and flow induced corrosion caused by reducing boiler water conditions and high local water velocity, typically near feedwater inlets or turning into the tubes from the inlet header.

Evidence or circumstances that occur prior to significant tube damage:

1. Problem with high levels of feedwater corrosion products; operating ranges for pH, cation conductivity or dissolved oxygen consistently outside recommended ranges, including persistent reducing conditions or excessive use of oxygen scavengers.
2. Flow Accelerated Corrosion in Feedwater System causing fouling of boiler feed pump or orifices.

“Best Practice” for Damage Defense

Closely monitor feedwater and boiler water chemistry when the unit is in-service. With the unit out of service and with probable cause, perform Ultrasonic Thickness (UT) checks on the ID of the economizer outlet stub tubes focusing near where the feedwater enters the economizer inlet header. Wastage generally extends to a length of 4" to 5" down the stub tubes from the inside surface of the header and can wear 360 degrees.

Failures appear as ductile overload rupture oriented around the largest local ID gouge. Damage is ID-initiated and looks like an orange peel. There will also be a notable absence of protective magnetite on tube ID.

9.4.3 Accelerated Flow Driven Stress Corrosion Cracking

Background

Corrosion Fatigue occurs through the combination of thermal stress, mechanical strain and corrosive waterside environment. Excessive stress and strain, imparted during unit transients axially cracks the protective ID oxide layer. When the unprotected tube material is exposed during a low pH chemical transient, pits form in the base material, rapid re-oxidation follows and corrosion accelerated axial cracks begin to form. Cyclic stress and strain opens and closes the cracks, when open new oxidation and deposits fill them causing the cracks to propagate. Eventually, the cracks propagate and with assistance from primary (hoop) stresses an ID-initiated, thick edged pin-hole leak occurs or with axial and/or circumferential cracks the whole tube section "blows out" near the source of mechanical strain (attachment, lug, pad weld, etc.).

The root cause is the synergistic effects of stress, strain and environment leading to a breakdown of the protective magnetite layer on a tube's inside surface.

Figure 9-36: Stress Corrosion Cracking

Note on Root Cause Remediation: Initiation and propagation of cracks of this nature are influenced by interactions between operating factors, chemical factors and stress / strain. Determining primary, secondary and tertiary influences must be done carefully to solve the problem.

Evidence or circumstances that precede significant tube damage are:

1. There are pH depressions (pH ~ 7-8) during shutdown and early startup caused by hideout then return of sulfates.
2. There have been problems with: high levels of feedwater corrosion products carrying over to the boiler and the operating ranges for PH, cation conductivity or dissolved oxygen are consistently outside recommended ranges.
3. There is persistent phosphate hideout causing pH depression.
4. The unit has been converted to cycling operation or an increase in the number of cycles.
5. There was a redesign of waterwall tube attachments to increase flexibility without analysis to prove the solution.

"Best Practice" for Damage Defense

1. Understand the mechanism: Corrosion fatigue failures occur near support attachments, usually in waterwall tubing but may also occur in economizer tubing under some conditions e.g. particularly where there is high heat flux and where stress from high restraint can develop. Typical locations include wind box casing attachments, buck stay attachments, and scallop bar attachments. Pay particular attention to locations where tubing carrying different media at different temperatures are attached. Corrosion fatigue is discontinuous. Multiple trans-granular cracks, small cracks adjacent to a main crack, initiating on the inside of the tube in-line to the highest applied stresses and propagating during transient periods. Transients result in cyclic strains driven by temperature differential between attachments and the tube. During peak strains, the protective magnetite layer will crack or existing cracks will open and deposits will fill voids.

2. With the unit in service, "best practice" for avoiding Corrosion Fatigue is to 1) know the number of Equivalent Operating Hours that the unit has experienced in cold unit thermal cycles and 2) if good lay-up techniques have been employed when the unit is out of service. Acknowledging that synergy must exist between a corrosive water environment and thermal/cyclic stress/strain for Corrosion Fatigue to occur. If the answer to 1 and 2 above is "A high number" and "No" and If the unit is in start up or shut down mode, and if pH, cation conductivity and dissolved oxygen levels are out of range then the threat of Corrosion Fatigue exists. Alternately, if the answer to 1 and 2 are "A high number and "No" and the synergy needed is acknowledged and if the unit has just achieved full pressure and pH, cation conductivity and dissolved oxygen are out of range, then the threat of Corrosion Fatigue exists.

3. Out of service, Eddy Current Testing (ferritic materials only), Digital Radiography, Magnetic Particle Testing and/or Phased Array Ultrasonic Testing may be used to locate and quantify damage. Determining the extent of damage is difficult due to access limitations, but vulnerable locations should be determined. Enlist qualified professional support when resolving the problem for the long-term as it may require redesign and / or modification to existing attachments. Tube sampling and metallurgical analysis remains the most viable approach to validating Corrosion Fatigue.

9.4.4 Supercritical Waterwall Cracking

Background

Supercritical Waterwall Cracking requires three conditions simultaneously: 1) excessive tube ID “ripple" magnetite deposits, 2) extreme temperature-induced stress and 3) a reducing corrosive environment. Each alone can be damaging but will not result in Supercritical Waterwall Cracking. Supercritical Waterwall Cracking is caused by heavy feedwater corrosion products that carryover and deposit on the tubes' protective oxide layer to form porous "ripple" magnetite deposits. The deposits insulate the tube from its cooling medium which causes an increase in the tube metal temperature.

Figure 9-37: Supercritical Waterwall Cracking

At the same time, fuel combustion results in the formation of protective fireside tube scale. A layer of slag forms on top of the scale creating a protective insulated environment that results in reduced heat transfer. Boiler efficiency calls for the need to de-slag these tube surfaces resulting in a tube surface temperature increase and compressive stress to the external tube crown surfaces causing axial creep strain. The process repeats and with renewed slag cover the surface temperature again decreases resulting in tensile stress to the external tube crown surfaces plus small, regularly shaped, circumferential cracks in the oxide scale layer. When cracking of the protective OD oxide scale occurs, tube surfaces are exposed and are attacked by a sub-stoichiometric corrosive environment. The corrosive products fill cracks and, with large thermal cycles from slagging/de-slagging, result in corrosion-enhanced thermal fatigue or Supercritical Waterwall Cracking. Eventually the cracking propagates into the tube steel. Eventually, primary (Hoop) stresses cause the tube wall to yield in an OD-initiated thick-edged, non-ductile failure.

Root causes of Supercritical Waterwall Cracking are the build-up of excessive amounts of internal $Fe3O_4$ "ripple" deposits, the stress of temperature cycles from slagging/ de-slagging, similar to the effects of corrosion-fatigue and fire-side corrosion with direct tube wastage only.

Evidence or circumstances that precede significant tube damage are:

1. Formation of excessive waterside deposits in once-through supercritical units not on oxygenated treatment
2. Flow Accelerated Corrosion in the feedwater system and fouling of boiler feed pump or orifices
3. Excessive need, often less than two years, between boiler chemical cleaning

"Best Practice" for Damage Defense

1. Understand the mechanism: Supercritical Waterwall Cracking generally forms as regular, parallel cracking, typically oriented circumferentially and is generally found on the fireside of waterwalls and membranes on coal-fired supercritical units. Examination of a cross-section reveals the cracks as sharp, "vee" or dagger shaped, generally trans-granular and filled with oxide. The presence of a sulfur-containing center spline and sulfur in the oxide is typical. Damage appears as circumferential, straight and un-branched cracking, or "alligator hide" like that caused by corrosion-fatigue, propagating perpendicular to the tube metal surface. The "families" of parallel cracks are frequently very tight, making them difficult to see without very close examination. At times they may appear as to be only shallow grooves in the magnetite cover. This damage is most common in waterwalls of coal-fired supercritical units that average higher tube metal temperatures. Some fireside tube wastage is common. Although less common, this damage has also been found in subcritical units. A related damage can be found in oil/gas fired units where higher heat flux leads to rapid tube temperature increases with damage accumulating as oxide-enhanced creep cracking. Crack orientation can be either circumferential or longitudinal in these cases.

2. With the unit in service, "best practice" for avoiding Supercritical Waterwall Cracking is to recognize and take steps to avoid threatening situations. A threatening situation for Supercritical Waterwall Cracking is: If unit is on, and if boiler waterwalls are confirmed dirty (Deposit Density >>30 mg/cm^2) and if iron ($\geq$ 10 ppb) and/or Copper ($\geq$ 2 ppb) levels run high from poor pH and dissolved oxygen control and if tube sections are in the path of a sootblower and if fluid temperature is above 735° F, then the threat of Supercritical Waterwall Cracking exists.

3. With the unit out of service, clean and Visually Inspect (VT) highest heat flux zones that are most susceptible. These are location above burners on the fireside of waterwall at the tube crown and/or membrane at the 4 to 8 o'clock position. If circumferential cracking is observed, quantify depth using Dye Penetrant (PT) or Magnetic Particle (MT) testing. If tube wastage from accompanying fireside corrosion is observed and excess deposition is anticipated, quantify wastage and deposit thickness using Pulse Echo Ultrasonic (UT) measurement. Pull tube samples to determine deposition rate and to perform metallurgical examination to validate the mechanism.

9.4.5 Hydrogen Damage

Background

Hydrogen Damage is caused by three conditions simultaneously: flow disruption with high boiler deposits, acidic contamination of the boiler water, and high heat flux. Each alone can be damaging but will not result in Hydrogen Damage. Hydrogen Damage is caused by the reaction of iron carbides in boiler tube steel, located in high heat-flux zones, with hydrogen produced as a result corrosion reactions, particularly those taking place in low pH water. The reaction produces methane (CH4) at the grain boundaries of the tube steel. As methane gas molecules accumulate, they force open micro fissures in the metal. Concurrently, local decarburization results in a loss of material strength. The fissuring worsens eventually leading to a through-wall failure.

Figure 9-38: Hydrogen Damage

The root causes of Hydrogen Damage are excessive deposits initiated by flow disruption and a source of high heat flux (flame impingement, burner misalignment) that causes Departure from Nucleate Boiling or DNB, Wick Boiling or Steam blanketing. These, in the presence of post-feedwater corrosion deposits that combine with acidic (chlorides or sulfides) contaminants, from condenser leaks or make-up or polishing water treatment system regeneration failure, yield more deposits that are mechanically and chemically unstable. The single-layer, stressed protective oxide layer experiences linear oxide growth. This insulates the tube steel from its cooling medium causing ever increasing tube metal temperatures and more multi-layer stressed oxide that eventually will shed and stop protecting the tube metal.

At the same time, hydrogen is being generated electrochemically and diffused into the unprotected tube surface. Diffused hydrogen reacts with iron carbide to form methane gas that is captive, pressurized and essentially explodes causing micro fissures to form, the material to decarburize and become brittle. Eventually, the primary (hoop) stresses cause the progressively damaged material to yield leading to a thick-edged, brittle failure or a window of material to blowout.

In short, to prevent Hydrogen Damage, keep boiler water circuits clean.

Evidence or circumstances that occur prior to tube damage occurring:

1. Excessive waterside deposits (>>30 mg/cm^2 for HP boilers).
2. Flow Accelerated Corrosion in feedwater system evidenced by fouling in the boiler feed pump or orifices.
3. Flame impingement due to burner change, misalignment or excessive wear leading to DNB and local tube deposits.
4. pH, cation conductivity or dissolved O_2, excessive use of O_2 scavengers consistently outside allowable ranges.
5. Boiler water samples appear black from high iron, copper and other suspended solids.
6. The use of weld backing rings, pad welding, use of canoe pieces and weld overlay that disrupts flow.
7. Heat flux change that causes deposits; change to higher caloric value coal, dual firing with gas, fuel change to oil or gas.
8. Flawed chemical cleaning of the boiler e.g. relocation rather than removal of boiler deposits.

“Best Practice” for Damage Defense

1. Understand the Mechanism: Hydrogen damage will generally initiate on the hot side of the tube where boiling occurs. Failures can occur with little or no wall thinning but in most cases some metal wastage; manifested as large pits or gouges on the tube ID covered in multiple layers of magnetite deposits. Suspect Hydrogen Damage if there are pad welds, boat samples, tube repairs - locations with local flow disruption. Final failure is thick-edged and appears embrittled. The tube microstructure is typically destroyed - decarburization around the pearlite layer accompanied by micro fissuring and inter-granular cracking. Thick deposits are found some containing chloride near to the scale/metal interface and oxide layers. Hydrogen damage is rare but once it occurs, damage is irreparable and can be widespread.

2. With the unit in service, “best practice” for avoiding Hydrogen Damage is to recognize and avoid threatening situations. A threatening situation for Hydrogen Damage is: If the unit is in service and if a major acid contamination event occurs and pH drops and if boiler waterwalls are dirty (>>30 mg/cm2) because iron ($\geq$ 10 ppb) and/or copper ($\geq$ 2 ppb) levels run high from poor condensate or feedwater pH and dissolved O2 control and if waterwalls are known to have been poorly maintained, causing flow disruptions and if chemical cleaning process errors are suspected and if flame impingement is possible then the threat of Hydrogen Damage exists. To avoid Hydrogen Damage, monitor water chemistry diligently at all times. Be mindful of low boiler water pH excursions at high loads and high condensate or feedwater cation conductivity levels.

3. Out of service inspections for Hydrogen Damage can be difficult because it is hard to identify. Pitch-Catch Ultrasonic (UT) methods can be effective for measuring changes in material properties (elasticity) caused by the damage but are time consuming. Often, operators that suspect Hydrogen Damage perform boiler hydro-tests at 1.5 times design pressure to force leaks. Damage locations are typically at horizontal or inclined tubes (burner bends and opening, roof tubes, upper furnace deflection arch and lower slope tubes).

9.5 METALLURGICAL CONSIDERATIONS

This section focuses on damage mechanisms that attack the microstructure of tubing and headers materials from time spent at elevated temperatures. Each damage mechanism, its failure modes and damage causes are explained. “Best Practice” damage defenses using the proactive and predictive Targeted Boiler Management approach to help keep damage from initiating or propagating is detailed. Metallurgical damage mechanisms include:

1. Long-Term Overheating and Creep Fatigue
2. Graphitization
3. Dissimilar Metal Weld Failure
4. Stress Fatigue

9.5.1 Long-Term Overheating and Creep Fatigue

Background

Long-Term Overheating/Creep Fatigue is time-dependent material strain or deformation under constant stress and elevated temperatures. In tests of materials, "design" creep life is defined as the time required for one percent elongation of a given material test coupon at constant temperature and stress. Long-term overheating/creep is unavoidable. Superheater and reheater tubing material selections are made to achieve a finite service life at theoretical tube metal temperature, and a margin for operating with an acceptable amount of creep degradation. However, excessive time above design temperature shortens tube life e.g. tube temperatures at or above the materials design temperature limit accelerates ID and OD oxidation. As tubing ID oxide grows, elevated surface temperatures result leading to material degradation e.g. carbon migration and colony formation, loss of ductility and creep cracking. The degraded material loses effective wall thickness until, with normal primary (hoop) stresses material yields and thick-edged, longitudinal rupture occurs. **Note**: ID oxide thickness measurement is a preferred method for calculating the tube life expended.

Figure 9-39: Long-Term Overheating and Creep Fatigue

The root-causes of Long-Term Overheating/Creep Fatigue are overheating of tube metal by a variety of causes, increased tube stress level caused by wall thinning and inadequate original design and/or material choices.

Evidence or circumstances that exist prior to tube damage are:

1. Normal increase in tube metal temperature caused by increase in oxide thickness
2. Excessive steam-side oxide
3. Excessive flue gas temperature
4. Bridging or channeling of boiler gas passages
5. Evidence of Solid-Particle Erosion in the turbine
6. Misguided redesign of the SH/RH heat transfer surfaces

“Best Practice” for Damage Defense

With the unit in service: Monitor and control superheater and reheater tube temperatures and section temperature profiles. **Note**: Temperature profiles are helpful in determining potential distribution of damage.

With the unit out of service: Guided by superheater and reheater on-line temperature measurement, perform Visual Inspection (VT) of suspect regions for tube OD oxidation, spalling and bulging. Inspect steam and water circuits at material transitions, at wall thickness changes of same alloy, in final leg of tubing just before the outlet header, on the lowest or wrapper tube, near refractory damage, at tubing surrounding a gas cavity or just past a cavity or gas channels, at tubing with heavy ID deposits and at tubes with high fire-side heat input. Inspectors are looking for hot-side (facing gas) OD tube wastage, bulging and plastic deformation, thick, brittle OD magnetite layer often with "Y" shaped grooves ("alligator hide"), accompanied by thick, hard and stratified ID scale with small longitudinal oxide fissures near bulges (release of which causes turbine solid particle erosion). On cleaned tube surfaces, wastage flats may be observed on the hot-side tube crown, with maximum "alligator hide” in the middle of flats.

If identified, perform Ultrasonic Thickness (UT) of tube ID oxide to determine expended life fraction. Determine remaining useful life by calculating the Larson-Miller Parameter. Remove tube samples for metallurgical examination to validate findings. Metallurgical examination should reveal critical steam-side oxide, a spherodized microstructure, reduced material hardness and intergranular and trans-granular creep cracking on ferritic materials.

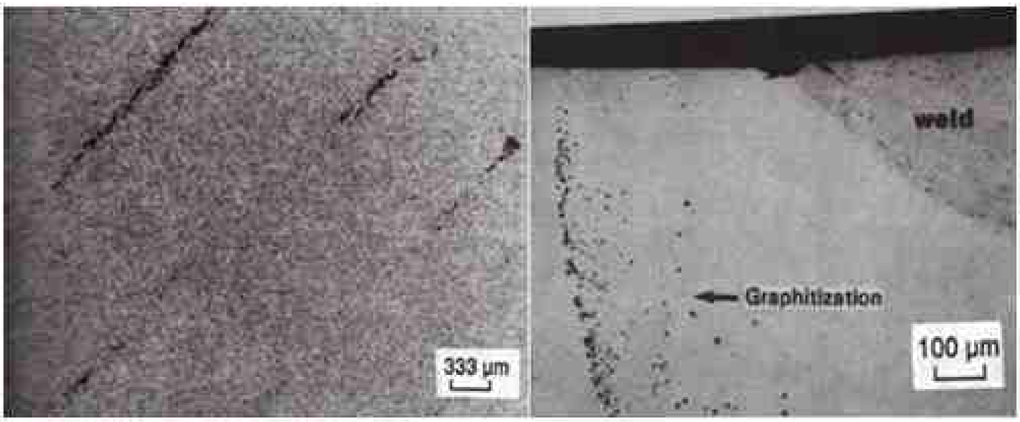
Austenitic materials will reveal sigma-phase microstructure and grain boundary cavities. Repeat oxide thickness measurement over HT superheater during general overhauls using a grid to map results. Determine remaining useful life by calculating the Larson-Miller Parameter. Perform tube sampling with metallurgical examination for verification. Forecast remaining useful life from results and plan replacement accordingly.

9.5.2 Graphitization

Background

Graphitization is microstructural material degradation caused by the decomposition of iron carbide into ferrite and graphite after prolonged exposure to elevated temperatures. Graphitization is not as prevalent in the power industry because of improved materials but remains a concern with local graphitization in repair welds (weld flaw).

Figure 9-40: Graphitization



Prolonged operation or local exposure of the weld heat-affected zone of carbon and carbon-moly steels at temperatures 450-700°C (840-1240°F) leads to microstructural degradation when ferrite and graphite are formed. This causes the material to become brittle. Eventually, the weld material will degrade until it yields to primary (hoop) and axial stresses and a brittle, thick-edged failure or weld separation occurs.

Root cause and evidence or circumstances prior to damage are the same: operation or local exposure at elevated temperature.

“Best Practice” for Damage Defense

Understand the Mechanism: EPRI's work (Foulds and Viswanathan) can be useful in getting started in identifying locations for Heat Affected Zone (HAZ)-related graphitization. Alternately, removal of material for small-scale miniature fracture mechanics (small samples of scale, almost non-destructive) for metallographic analysis. Samples removed for metallurgical tests can also be used for bend tests for a qualitative measure.

With the unit in-service, monitor steam and gas temperatures in the low temperature sections of the reheater and superheater containing carbon or carbon-moly steels. Prior experiences with graphitization may justify addition of instrumentation if lacking. Compare gas and steam temperatures to the material oxidation temperature and flag areas of concern with narrow margins.

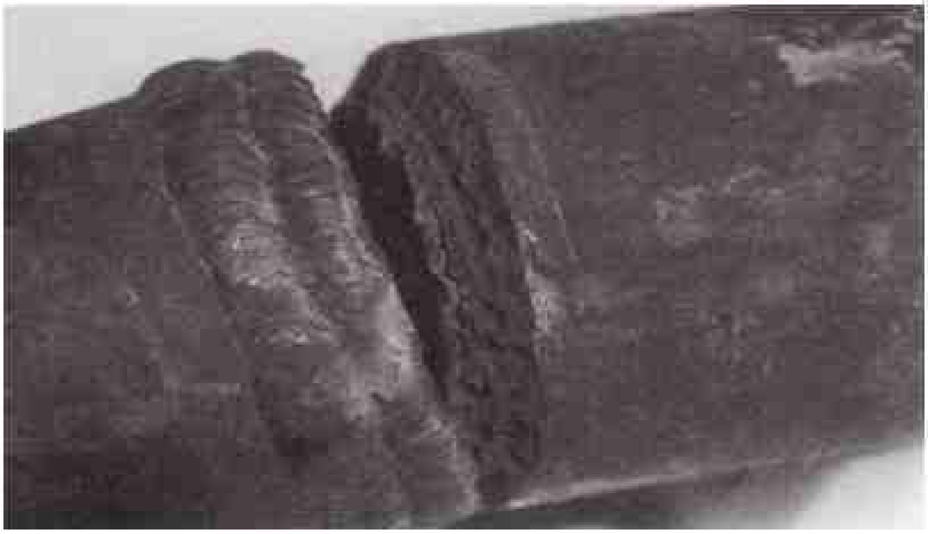
With the unit is out of service: metallurgical examination is key to identifying graphitization. The most common form of graphitization is found in the weld fusion line or heat-affected zone of welds in carbon and carbon-molybdenum steel tubing and is usually oriented circumferentially. The microstructure yields graphite particles or nodules. A second form can be found in materials some distance from welds where metallurgical examination finds that the material's graphite nodules are uniformly dispersed.

9.5.3 Dissimilar Metal Weld Failure

Background

Dissimilar Metal Weld Failure is caused by welding austenitic stainless steel (SA-213 321H, SA-213 347H, and SA-213 304 H) materials to ferritic alloy (SA-213 T22) materials with high service temperatures and/or mechanical stresses using nickel-based weld filler material. Dissimilar Metal Welds experience creep and mechanical fatigue at the ferritic/nickel-based weld joint which leads to stress accumulation and eventual weld failure. Older boilers (designed prior to 1980) are much more susceptible to Dissimilar Metal Weld Failures than newer boilers because of advances in knowledge and use of improved weld filler metals.

Figure 9-41: Dissimilar Metal Weld Failure



The root-cause of failure is creep damage that accumulates at the austenite grain boundaries on the ferritic side of the weld joint. The weld separates here. Damage accelerates when mechanical stresses are present.

Evidence or circumstances that occur prior to tube damage are:

1. Excessive steam side oxide with evidence of excessive exfoliation like solid particle erosion in turbine.
2. Excessive temperatures measured by thermocouples in vestibule or header areas.
3. Distorted or misaligned tube rows.
4. Conversion of the unit to cycling service that causes an increase in the number of stress cycles.
5. The redesign of the superheater or reheater circuits that could shift heat absorption patterns to other areas.
6. The addition of supports without consideration of stresses added to dissimilar metal welds.
7. Failed tube supports and/or lugs and/or location of dissimilar metal welds too close to fixed supports.

“Best Practice” for Damage Defense

With the unit out of service: identify locations with austenitic to ferritic dissimilar metals and with nickel-based filler material. Perform Visual Inspection (VT) at the locations (the superheater, reheater in the convection pass, in vestibules and in the penthouse) considering the welds and the general condition of the surroundings. If there is indication of an oxide notch on the outer surface of the ferritic to nickel-based heat affected zone, perform Digital Radiography (RT) and pull tube samples for metallurgical examination using methods for assessing creep damage in these zones. If the examinations are indicative of creep fatigue at or around the weld heat-affected zone, plan replacement of the old dissimilar metal welds with upgraded shop- welded DMW coupons. Welds in the field are easier because they are joining similar metals.

9.5.4 Stress Fatigue

Background

Tube and header material fatigue is from the accumulation of low-cycle stresses that result in material yield in the form of cracking. These stresses may be induced thermally or mechanically. Fatigue is primarily associated with tubing at attachments or restraints and header stubs. It is manifested as the OD-initiation and stable propagation of a trans-granular crack caused by:

Figure 9-42: Stress Fatigue

1) Thermally-induced stress and dynamic cycling that leads to cold working of the material then cracking,
2) Mechanically-induced stresses and dynamic cycling that leads to cold working of the material then cracking or,
3) Gas flow-induced excitation of a tube sections' natural frequency and vibration which leads to cold working of the material then cracking. All result in thick-edged failures when a critical crack size is reached and material yields to primary (hoop) stresses.

Root-causes of fatigue can be:

1) Conversion of the unit to cycling operation and an increase in the number of cycles,
2) Tube bends and headers with unanticipated and excessive cyclic stresses whose sources include constraint of thermal expansion, excess mechanical loads or flow-induced vibration,
3) Welds from poor weld geometry especially at final joint.

Note on Attachments: Stresses caused by thermal gradients can concentrate at weld heat-affected zones and can cause cracking of the weaker material, if materials with significantly different coefficients of expansion are joined.

Evidence or circumstances that occur prior to tube damage are:

1. Conversion of the unit to cycling operation.
2. Location of dissimilar metal welds near fixed supports.
3. Failure of tube supports and lugs.

4. Flue gas standing wave causing vibration after gas flow path has been altered.
5. Distorted or misaligned tube rows found during routine inspection.
6. Excessive relative motion between tubes and headers during unit transients.
7. Headers, principally stub tubes, not allowed to expand and contract freely.

Note: Material endurance limit can be affected by surface conditions - smoothness, notches and by corrosion, which can either cause notches or magnify their effect (corrosion-accelerated fatigue).

“Best Practice” for Damage Defense

Understand the Mechanism: Tube and header material fatigue is from the accumulation of low-cycle stresses that result in material yield in the form of cracking. These stresses may be induced thermally or mechanically. Fatigue is primarily associated with tubing at attachments or restraints and header stubs. It is manifested as the OD-initiation and stable propagation of a trans-granular crack caused by:

1) Thermally-induced stress and dynamic cycling that leads to cold working of the material then cracking,

2) Mechanically-induced stresses and dynamic cycling that leads to cold working of the material then cracking, or

3) Gas flow-induced excitation of a tube sections' natural frequency and vibration which leads to cold working of the material then cracking. All result in thick-edged failures when a critical crack size is reached and material yields to primary (hoop) stresses.

With the unit in service: Compile data for estimating expended fatigue life. Include number of hot starts, cold starts, full-load trips and operating hours per section and a chronological measure of all that will indicate changes in mode of operation (base-load, load following/cycling, peaking). Use data to estimate expended fatigue life fraction (actual cycles/design cycles). Establish inspection locations and frequency per component for use in the boilers monitoring and inspection plan.

With the unit out of service: OD-initiated, trans-granular, single-crack manifestation makes fatigue easy to locate and trouble-shoot, within the constraints of access, using many existing NDE techniques. Organize inspection plans as outlined above and based on typical locations: on tube bends, particularly at the inner radius, outer radius or neutral axis, and headers, at nipples or stub tube near either end of the header. Visual Inspection (VT) for identifying suspect area and Dye Penetrant (PT) testing 360 degree to confirm surface OD-initiated cracking. At welds and attachments, particularly solid or jammed sliding attachments: Visually Inspect (VT) and then use Dye Penetrant Testing (PT) for surface and/or Magnetic Particle Testing (MT) for sub-surface cracking depending on access and location. Cracks may be filled with oxide depending upon the service condition. Phased Array Ultrasonic Testing (UT) or manual grinding is required to quantifying crack depth depending on access and location. **Note**: Fatigue cracks may also occur in material that has been damaged by creep that is primarily stress-driven.

9.6 OPERATION CONSIDERATIONS

This sub-chapter focuses on damage mechanisms that result from an unusual operational event or series of events that directly influence tubing and headers. Each damage mechanism, its failure modes and damage causes are explained. "Best Practice" damage defenses using the proactive and predictive Targeted Boiler Management approach to help keep damage from initiating or propagating is detailed. Operation influenced damage mechanisms include:

1. Short-Term Overheating
2. Damage from Falling Objects

9.6.1 Short-Term Overheating

Background

Short-Term Overheating occurs when tube metal temperatures rise above critical limits for a brief period of time. Occurrences may be preceded by sudden, abnormally low coolant flow or excessively high combustion gas temperature. The damage mode depends on the metal temperature that the tube experienced just prior to failure. For example: with a rapid increase in tube metal to above the materials critical temperature and with normal primary (hoop) stress, then considerable decrease in tube wall thickness from bulging will result in a thin-edged "fish mouth" ductile tube failure. However, if the tube reaches the materials' upper critical temperature with normal primary (hoop) stresses, then thick-edged failure with little swelling and with increased material hardness will result.

Figure 9-43: Short-Term Overheating

Root-cause is: Flow interruption caused by partial blockage from maintenance activities, loss of coolant tube failure or plugging of waterwall orifices by feedwater corrosion products.

Note: the root-cause should also be validated by examination of the transformation products in tube microstructure to differentiate short-term from long-term overheating/creep.

Evidence or circumstances that occur prior to tube damage are:

1. Excessive waterside deposits.
2. High pressure drop across circulation pumps.
3. Evidence of shortcoming in chemical cleaning process.
4. Feedwater flow interruption.
5. Maintenance activity.
6. Operating excursions that can be seen from logged data.

"Best Practice" for Damage Defense

With the unit in-service: note changes in feedwater inlet-to-superheater outlet pressure over time, changes in tube temperature profiles, carefully control start-up and shut-down temperature ramp rates.

With the unit out of service: if precursors are observed, or after a short-term overheating event, Perform Visual Inspection (VT) of tubing OD for evidence of bulging, Visual Inspection (VT) ID with video probe for locating blockage and/or internal tube deposits. Perform Ultrasonic Thickness testing (UT) for quantifying wall thinning and/or internal tube deposits on ferritic tubing and metallurgical examination for validation. Use a handheld magnet for locating internal tube deposits on austenitic tubing. If boiler is controlled circulation design, boiler may be filled to separator with warm water, turn boiler circulating pump on and use infrared thermograpy to view tubes for Pluggage.

Damage is typically located in waterwall tubes at or above burners or under upper furnace deflection arch. **Note**: Failures may not occur where the interruption of the tube flow occurs but in the higher heat flux zones downstream. Thus, an inspection of the whole length of tubing is essential in the 9 to 3 o'clock position in superheater and reheater tubes near the lower bends of ferritic and/or austenitic panels.

9.6.2 Damage from Falling Object

Background

Falling-Object Damage results from abrasion or impact to horizontal or near horizontal tube surfaces, typically to bottom hopper slope tubes.

Root-causes are large amounts of fused coal ash deposit, re-solidified molten slag deposit or auxiliary components detaching and falling from upper furnace, radiant or platen pendant zones causing tube leaks by:

1) Tube abrasion or indirect impingement causing tube OD thinning that, in combination with primary (hoop) stresses will result in a thin-edge, ductile "fish mouth" tube rupture.

2) Mechanical impact or direct impingement causes denting, flow restriction, loss of cooling downstream, short or long-term overheating, tube swelling or bulging and a thin-edge, ductile "fish mouth" tube rupture and/or failure of seals and attachments.

Figure 9-44: Damage from Falling Object

Evidence or circumstances prior to tube damage are:

1. Burning coal with a high slagging propensity (high in sodium and/or chlorine)
2. Large furnace plan area with low local velocities
3. Low flue gas temperatures
4. Thermal cycling and/or running high tube temperatures
5. Inadequate sootblowing of pendant superheater

“Best Practice” for Damage Defense

With the boiler in service: Understand the characteristics of the fuel(s) being used as guides for operation to defend against boiler slagging. Examples of derivatives from analytical methods:

- Weight percentages of bottom, clinker and fly ash (Laboratory-generated ash samples)
- Fouling propensity based on sodium equivalent criterion (bituminous coal)
- Deposit-forming propensity of bituminous and Lignite ash based on sodium content.
- Ash fouling propensity based on sodium and chlorine content of coal
- Slagging index of coal ashes from base-acid ratio and sulfur content
- Slagging propensity versus critical ash temperature (Laboratory derived)
- Fouling index of coal influenced by sodium content (western bituminous coal)
- Sintering rate based on combination Silica Ratio and Iron Oxide Content
- Fouling propensity of ash based on base-acid ration and sodium content

Additionally, operations personnel should be continually aware of boiler pressure part conditions through instrument inputs and direct observation.

With the boiler out of service: Perform Visual Inspection (VT) for: 1) Tube denting: On the fireside of water wall sloping wall tubes and ash hopper slope tubes. Dents are typically located within the first four feet from sidewalls at each end of the ash hopper at the 9 to 3 o'clock position. 2) Tube bulging; Discovery of significantly dents should be followed by inspection downstream of the tube up to the outlet header for signs of short or long-term overheating at the 4 to 10 o'clock position, as well as careful inspection of adjacent structural members. 3) Tube abrasion: Inspect for tube thinning of slope tubes with evidence of external erosion on the fireside at 4 to 10 o'clock position and structural damage. If suspicious areas are identified, perform Ultrasonic Testing (UT) of tube thickness for quantifying tube wall bulging, wastage and Dye Penetrant (PT) Testing for identifying and UT for quantifying structural cracking.

9.7 QUALITY ASSURANCE AND QUALITY CONTROL CONSIDERATIONS

This sub-chapter focuses on damage mechanisms that are significantly influenced by human error. Each damage mechanism, its failure modes and damage causes are explained. “Best Practice” damage defenses using the proactive and predictive Targeted Boiler Management Approach to help keep damage from initiating or propagating are detailed. QA/QC - influenced damage mechanisms include:

1. Weld and Repair Defects (Lack of Training, Procedural Non-compliance)
2. ID Oxygen Pitting Corrosion (Procedural Non-compliance)
3. OD Rubbing and Fretting (Incomplete Inspections)

4. Chemical Cleaning Damage (Procedural Non-Compliance)
5. Coal Particle Erosion (Lack of Maintenance)
6. Low-Temperature Creep (Procedural Non-Compliance)
7. Sootblower Erosion (Lack of Maintenance)

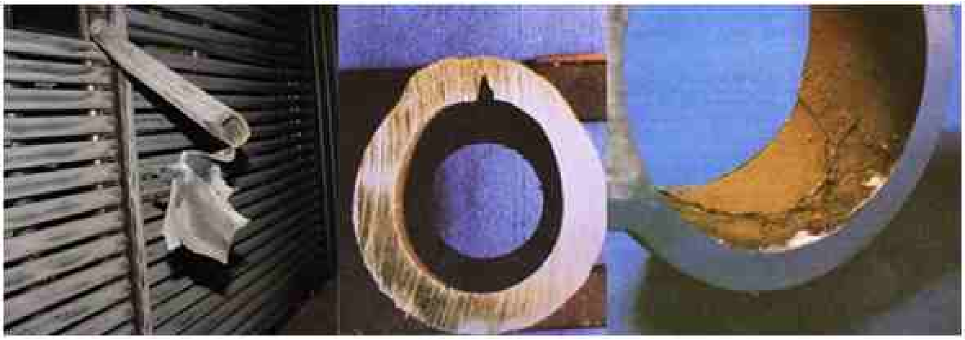
9.7.1 Weld and Repair Defects

Background

It is the authors opinion that the lack of skilled tradesman guided by rigid policies and procedures dominates all other challenges to the power production industry. Simply put, Quality Assurance and Quality Control is lacking. What makes the problem worse is that the root causes of many of the boiler damage mechanisms can be tied directly to the lack of QA/QC:

1) SHRH/WW short-term overheating: Residual weld spatter and/or debris left inside tube leads to flow restriction leads to elevated tube metal temperature leads to short-term overheating and tube failure
2) WW under deposit corrosion – includes:
a) Hydrogen damage: Burn-through in pad welds=>flow disturbance=>deposition=>under deposit corrosion=>failure
    b) Acid phosphate corrosion: Excessive ID weld material=>flow disturbance=>deposition=>under deposit corrosion=>failure
    c) Caustic gouging: Use of weld backing rings=>flow disturbance=>deposition=>under deposit corrosion=>failure
3) SHRH Graphitization: Temperature excursions experienced during welding + susceptible material (T1A)=>metallurgical changes (ferrite & graphite formation)=> embrittlement=>failure
4) SHRH/WW mechanical fatigue: a) Large fillet weld toe=>stress riser=>fatigue, particularly near attachments=>cracking=>failure, b) Improper repair weld geometry=>fatigue, particularly near attachments=>cracking=>failure

Figure 9-45: Weld and Repair Defects



5) WW corrosion fatigue: a) Poor weld and/or attachment design=>constraint of thermal stresses=>excessive stress accumulations other contributing factors=>corrosion fatigue, b) Poor weld and/or attachment design=>constraint of thermal stresses=>excessive stress accumulations other contributing factors=>mechanical fatigue

6) SHRH dissimilar metal weld failure: a) Poor weld and/or attachment design=>constraint of thermal stresses=>excessive stress accumulations other contributing factors=>dissimilar metal weld failures, b) Improper execution of induction pressure welds + dissimilar metals=>dissimilar metal weld failures

7) SHRH stress corrosion cracking: a) Improper weld procedures + candidate materials=>sensitized material=>stress corrosion cracking b) Weld defects + candidate materials=>initiation site for stress corrosion cracking.

“Best Practice” for Damage Defense

With the boiler out of service, apply the following non-destructive methods to detect these flaws to assure weld integrity

Cracking - UT, PT, MT, VT

Inadequate joint preparation - RT, UT

Incomplete fusion - UT

Laminations - UT, PT, MT, VT

Overlap - PT, MT

Porosity - RT, PT, VT

Slag inclusions - RT, UT

Undercut - RT, VT

Butt joints - RT, UT, PT, MT, VT

Corner Joints - UT, PT, MT, VT

Tee Joints - UT, PT, MT, VT

Lap joints - PT, MT, VT

Potential Damage Locations:

- At misalignments: undercuts, concavity or convexities, excessive reinforcements, poor reinforcements, poor reinforcement angles, overlaps, burn through, arc strikes, slag inclusions, tungsten inclusions, oxide films, weld dressings, spatter, arc craters.
- At cracks or fissures: porosity, heat-affected zones (microstructural alterations), weld metal and heat-affected zones segregation, base plate delamination.
- At changes in section and/or stress concentrations: particular weld joint types.

"Best Practice" for Damage Defenses

Welder training and certification, 100 percent digital radiography of pressure welds, quality assurance/quality control program developed, implemented and audited on a regular basis.

9.7.2 ID Oxygen Pitting Corrosion

Background

Oxygen pitting damage is caused by exposure of the internal surfaces of waterwall, superheater or reheater tubes and headers to residual moisture after unit shut down. The highly oxygenated and/or low pH condensate damages the protective oxide layer and initiates pitting. The root-causes of this damage are the influences of poor lay-up practices, poor shutdown practices, forced cooling and /or improper draining and venting procedures, improper chemical cleaning or deposition of chemicals on susceptible surfaces. In all cases, the pitting propagates to the point that material yields to the primary (hoop) stresses and thin-wall pinhole or tube rupture occurs.

Figure 9-46: ID Oxygen Pitting Corrosion

Evidence or circumstances that exist prior to damage occurring:

1. Indications that stagnant, oxygenated water may have rested in tubes during shutdown/layup particularly in the economizer and reheater
2. Evidence of shortcomings during unit shut down and layup e.g. uncertainty about water quality, nitrogen blanketing, hydrazine passivation or evidence of air in-leakage
3. Steam-side deposits in reheater tubing, particularly sodium sulfate
4. High levels of Na or SO_4 in the steam.

“Best Practice” for Damage Defense

With the unit in service: Have procedures written to address boiler lay-up. Requirements to keep damage from occurring will differ by the time the unit is scheduled to stay out of service and the work that is slated while off. Prior to shut down, use infrared thermography to inspect boiler vents and drains for signs of bypassing. If leakage is identified, slate components for repairs.

With the unit being removed from service, watch water and steam chemistry pH and cation conductivity for upsets during unit shut down. Also charge boiler water with ammonia to buffer pH. If possible, prior to breaking vacuum on shut down, drain reheater to the condenser.

With unit out of service, Buffer boiler water pH with ammonia and blanket steam circuits with nitrogen. If ID Oxygen Pitting damage is suspected, perform Ultrasonic Thickness (UT) measurements at locations where boiler water can layout in tubes during shutdowns.

Damage locations in water circuits are primarily at horizontal and sloped waterwall tubing, economizer tubing and headers. Pits in waterwalls caused by low pH are localized, numerous, closely spaced pits and free of deposits. Pits tend to be deep, through-wall relative to length. Pits are small and often full of corrosion products and sometimes undercut the surface making them hard to detect. Pits are autocatalytic i.e. conditions within the pit stimulate continued activity of the corroding compound. **Note**: Pitting can act as stress-concentration sites that can foster development of corrosion fatigue cracks and other stress related failures.

In the superheater and reheater at the bottom of ferritic pendent loops and low points of sagging ferritic horizontal tubes, conduct UT for wall loss, if strongly suspected, take tube samples and examine to verify damage is ID Oxygen Pitting. Pits are jagged and rough, short and deep. Stagnant and oxygenated water conditions: numerous and closely spaced or isolated pits covered with caps of corrosion products, particularly red hematite. Perform video (VT/Video probe) inspection to determine the extent of damage. Note: Quantifying damage is difficult unless it is widespread with significant wall loss. This difficulty is compounded by access and surface preparation requirements.

9.7.3 Rubbing and Fretting

Background

Rubbing and Fretting Damage results from adjacent superheater or reheater tubes or attachments coming into direct contact through vibration, impact, rubbing, etc. with one another causing material wear and accelerated oxidation of the surfaces by continuous removal of the protective oxide layer. The root cause of Rubbing and Fretting Damage is metal to metal contact between tubes and attachments causing surface wear and eventual tube ductile thin-edged fracture or attachment material yield and failure.

Figure 9-47: Rubbing and Fretting

Evidence or circumstances that occur prior to tube damage are:

1. Missing or nonfunctioning tube supports
2. Inadequate tube supports
3. Distorted or misaligned tube rows
4. Increased velocities due to ash accumulation
5. Running high excess O_2
6. Boiler “standing wave” harmonic vibrations

“Best Practice” for Damage Defense

With the unit in service: Be conscious of unusual and audible gas-path tube vibration especially just after the boiler has been cleaned or modifications made that could change the tubing's natural frequency and cause a standing wave. Observe tube assembly motion near water cooled spacers.

With the unit out of service: Visually inspect (VT) tube assemblies looking for parallel or perpendicular tube-to-tube or tube-to attachment contact. Quantify damage with Ultrasonic Thickness (UT) measures and/or use weld gauges in tight locations to quantify damage. Damage will appear as obvious metal to metal contact on tube surfaces. There are smooth wastage flats, missing ash or fireside oxide scale on fireside tubes. Rubbed area may have a shape that matches the profile of the adjacent tube.

9.7.4 Chemical Cleaning Damage

Background

Chemical Cleaning Damage is generalized corrosion of the boiler base metal by chemical cleaning solvent caused by one or more improper operations during the cleaning.

Figure 9-48: Chemical Cleaning Damage

The root-causes are one or more improper procedural operations during the cleaning process like:

1. Use of an inappropriate cleaning agent,
2. Excessively strong agent concentration,
3. Excessive cleaning times,
4. Excessive temperatures,
5. Failure to neutralize agent after the clean,
6. Inadequate drain or rinse cycles, or
7. Breakdown of the corrosion inhibitor.

Evidence or circumstances that occur prior to significant damage:

1. Evidence of a shortcoming during the chemical cleaning process (Above)
2. Evidence that iron content in agent continued to increase, not level out, after cleaning process ended

“Best Practice” for Damage Defense

With the unit in service: Careful Preparation e.g. knowledge of deposit chemistry, careful selection of solvent, careful preparation of cleaning and disposal procedures, careful preparation of cleaning equipment and piping.

With unit out of service (Cleaning): Careful execution and waste disposal e.g. experienced personnel involvement; precise execution of procedure; careful monitoring of start-up boiler water chemistry and proper disposal of waste.

With unit out of service (damage suspected), visually inspect tube ID with video probe in high heat flux areas, perform Ultrasonic Thickness (UT) measures or take tube samples to verify and quantify wall loss in affected areas such as at bottom inside of tubing and headers where residual low pH boiler water and cleaning agent can lay out and stagnate after chemical cleaning in the 5 to 7 o'clock position, and at tube ends in mud drums and mixing headers. The appearance of the affected tubes and headers are jagged and rough, with straight-sided or undercut pits or as generalized wall thinning. Although infrequent, thinning has been known to occur around entire circumference. Pitting found soon after event is relatively free of oxides and deposits.

Note:

- Pull tube samples to inspect for cleanliness to validate cleaning
- Chemical cleaning of waterwalls can lead to increased incidences of Hydrogen Damage (given a source of acid contamination).

9.7.5 Coal Particle Abrasion

Background

Coal Particle Erosion causes waterwall tube OD thinning from direct contact with the pre-ignition fuel stream. This occurs when tube protection fails or there is fuel stream and / or tubing misalignment. Two primary manifestations exist; one in cyclone-fired coal units and the second in wall-fired or tangentially fired PC units.

1) In cyclone-fired units, when the replaceable wear liners located near the end of the burner scroll and/or the refractory covering the waterwalls in the furnace fails. High velocity combustion air is used to impart a whirling motion to air and entrained coal particles. The impact of these particles can wear out resistant liners and refractory coatings that are intended to protect tube surfaces.

2) In PC Units, misaligned or worn burners' impact in-line or adjacent waterwall tubing causing exposed tube surfaces to erode until primary (hoop) stress takes over and tubing fails.

Figure 9-49: Coal Particle Abrasion

There are several candidate root causes for Coal Particle Abrasion:

1. Failure of protective coatings or devices
2. Mal-adjustment of primary, secondary and/or tertiary air at burners or cyclones
3. Misalignment of burners
4. Misalignment of waterwall tubing
5. Excessively worn burners

Several things could be happening prior to significant tube damage occurring:

1. Extension of inspection intervals
2. Fuel change to that with high quartz and/or pyrite content
3. Flawed burner change-out or modification

"Best Practice" for Damage Defense

Operators are a "best practice" if they visually inspect conditions in the furnace on a routine basis.

Maintenance is the "best practice" damage defense against Coal Particle Abrasion. Raw coal particle sizing (Table 9-7) and silica/quartz content should be determinants in defining maintenance frequency.

Table 9-7: Abrasive Index Based on Particle Sizing of Quartz and Pyrite

Abrasiveness	Particle Diameter (µm)	Relative Abrasive Index	Abrasive Index
Low	<5	0	<0.02
Medium	5-45	0.5I1a	0.02-0.08
Medium-High	>45	I1a	0.04-0.28

Table 9-8: Abrasive Index Based on Weight Fractions of Quartz and Pyrite

Abrasiveness	Abrasive Index ((Cq + xCp)Iq)
Minimal	0.01
Moderate	0.01-0.025
High	0.025-0.05
Exceptionally High	>0.05

Some maintenance may be done with the unit in service such as controlling coal mill fineness. Otherwise, when there are opportunities, technicians should be dispatched for visual inspection of refractory coatings and wear-resistant liners. As with other similar erosion mechanisms, final failure of the tube occurs when the thinned wall yields to hoop stresses and ductile failure occurs. If extensive liner or tubing wear is identified, UT measures to quantify existence and extent of damage should be performed at the throat or quarrel of corner or front and rear wall burners or at tubing near replaceable liners in cyclone burners at the 12 to 3 o'clock or 9 to 12 o'clock position. Inspectors should watch for tube wall thinning or flats on tube surfaces, zones with little or no surface ash, local surface hardening and / or grooving and fresh rust on tubes after unit washing.

9.7.6 Low Temperature Creep

Background

Low Temperature Creep is creep cracking driven dominantly by residual stress created during manufacture.

The root-causes of failure are unanticipated sources of high residual stress and service stress and/or high tube bend differential hardness in relatively low temperature tubing. It can be found in either water or steam circuits in that it occurs between 298°C and 421°C. Cracking is OD initiated. Failures from this mechanism are typically preceded by a period of stable inter-granular or trans-granular growth of creep voids and crack growth that accumulates over time through the synergistic effects of high residual and service stresses. It propagates until primary (hoop) stress causes a thick-edged crack rupture. Low temperature creep is primarily stress-driven and occurs, initiated from the cold forming process, enhanced membrane stress from ovality and/or routine operation and temperature over time.

Figure 9-50: Low Temperature Creep

“Best Practice” for Damage Defense

With unit in service: Good material and procedural specifications are the best defense against Low Temperature Creep. Low Temperature Creep is introduced during cold forming of tubing (and piping) bends at the bend outside radius. Prior to receipt into the warehouse, new bent tubing should be Visually Inspected (VT) with ovality over 8 percent or hardness greater than 220-240 HV are most likely candidates for low temperature creep.

With unit out of service: Perform visual inspection of outside surfaces on tube bends with Magnetic Particle (MT) testing if bends are accessible. Hydrostatic testing with visual inspection is recommended for areas with limited access. Areas of interest are in the low temperature sections of the reheater and primary superheater or high temperature regions of the economizer.

Low Temperature Creep causes OD initiated, inter-granular or trans-granular crack growth in high-stress locations, especially the outside surface of bends with evidence of grain boundary creep cavitation and creep voids. The direction of the cracks propagation will depend upon the bends applied and residual stress fields.

9.77 Sootblower Erosion

Background

Sootblower erosion causes accelerated OD tube wastage by direct material removal and removal of the fireside oxide that increases the oxidation rate.

When the sootblower is operated, supply air or steam entrains and accelerates abrasive ash particles and possibly moisture or condensate from wet air or low enthalpy steam. This causes local tube OD erosion on impacted tube surfaces that result in thinned tube walls. Eventually the tube wall yields to constant primary (hoop) stresses and a thin-edged, longitudinal "fish mouth" failure occurs.

Root causes of sootblower erosion can be improper sootblower operation and / or maintenance, insufficient superheat in sootblower supply steam or moisture removal in air supply and improper sootblower alignment.

Figure 9-51: Sootblower Erosion

Evidence prior to significant tube damage occurring:

1. Poor or non-existent sootblower maintenance
2. Burnishing or polishing of tube outside surfaces
3. Very localized wear and wastage flats.
4. Fresh rust on tubes after unit washing

"Best Practice" for Damage Defense

Maintenance is "best practice" damage defense against sootblower erosion. Note that root-causes of sootblower erosion and boiler slagging, bridging and fouling are distinct and different. They should not be confused.

Frequent sootblower alignment and pressure checks are recommended while the unit is on-line. When there are opportunities, technicians should be dispatched and Visually Inspect (VT) waterwalls adjacent to wall de-slaggers and superheater and reheater tubes in the path and within blowing radius of retractable sootblowers. Sootblower erosion is manifested the same as other erosion processes except damage is local and not widespread. It appears as tube wall thinning caused by external tube wastage. The erosion pattern will be angled to the tubes from the direction of the blow. As erosion becomes more severe, flat spots will form. Few or no ash deposits are evident. Horizontal, tight pitched thermal fatigue cracks on tube surfaces are possible if adequate moisture is present in the blowing medium.

9.8 BOILER CONDITION MONITORING AND DIAGNOSTICS

Background

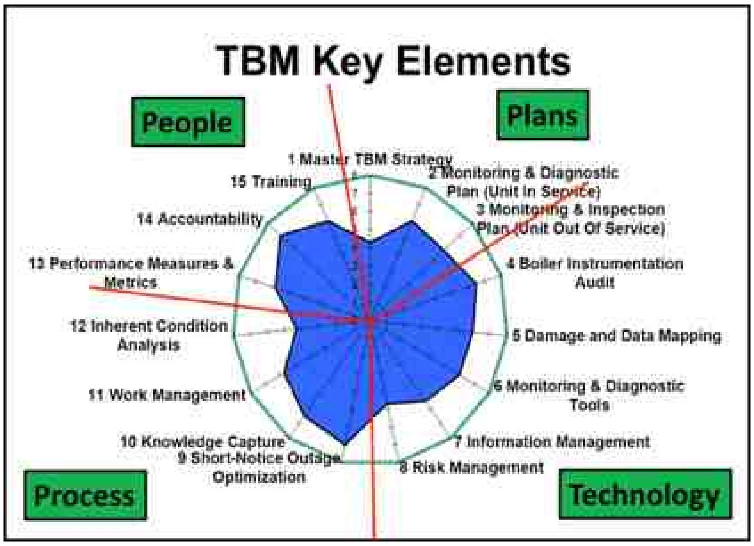
If our "Best Practice" vision is to have vast territories electrified by extremely reliable coal-fired power plants, with oversight and technical support provided on-site and by regional Monitoring & Diagnostic (M&D) Centers, then it becomes essential that "best practice" technologies for condition monitoring and diagnostics be understood.

Computerized equipment condition monitoring and diagnostics requires that a large amount of input data be processed for use by people. This section addresses the functionality that users find most helpful when considering periodic and continuous boiler monitoring and diagnostic software applications. Condition monitoring and diagnostics of boiler tubes and headers with the unit out of service is first.

Monitoring and Inspection (Unit Out of Service) Software

Many non-destructive and destructive inspection methods combined with databases and information management software exist and are used to determine the condition of boiler components when it is out of service. In Section 9.2.1 several "Best Practice" elements and attributes related to periodic condition monitoring and inspections were outlined (Figure 9-52).

Figure 9-52: TBM Key Elements



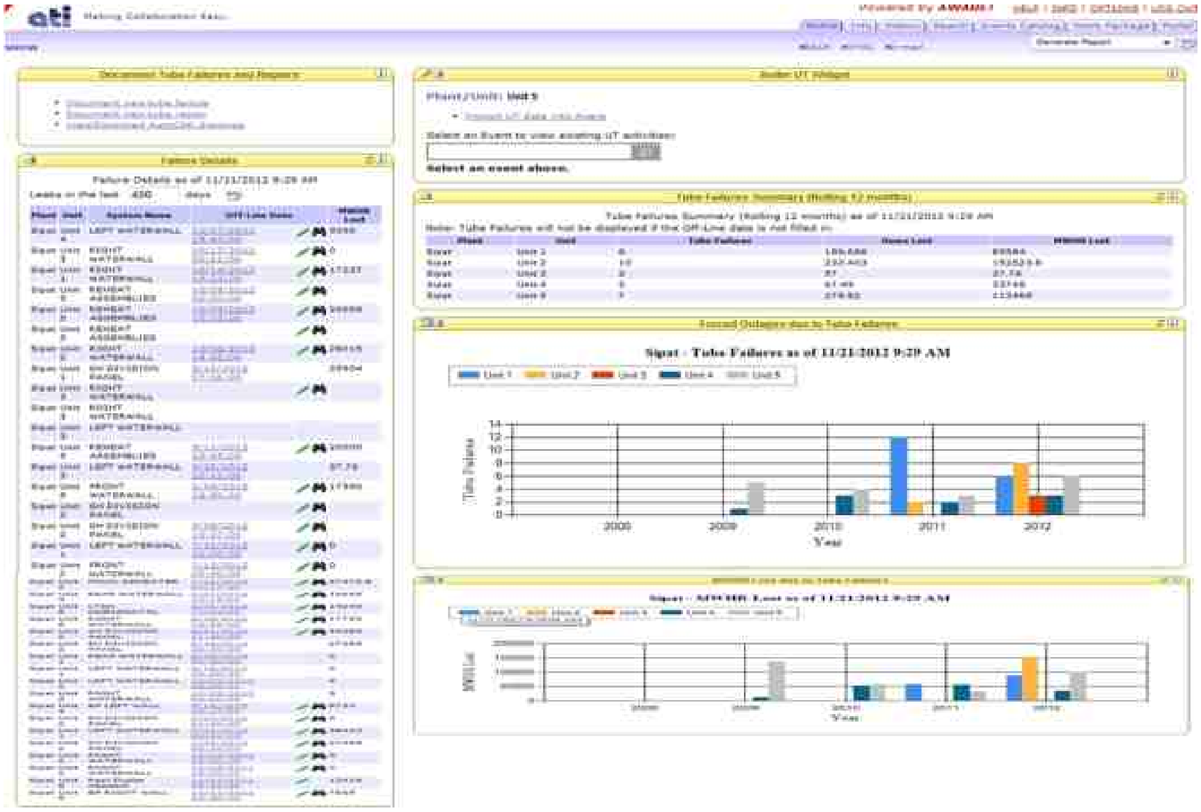
The principle elements include: (1) The Monitoring and Inspection Plan (Unit Out of Service), (2) Damage and Damage Mapping, 6 Monitoring & Diagnostic Tools, (3) Information Management, and (4) Risk Management. A summary of all "Best Practice" attributes follows.

Summary

Monitoring and Inspection tools consist of software and databases for use in archiving and trending non-destructive inspection data, data mapping and failure history.

The database: the database should include a universal and comprehensive set of solutions. It must be a closed database (SQL, Oracle, etc.) and not a traditional open system (Word documents or Excel spreadsheets). The database must be well designed and normalized to meet the data storage and analysis requirements of any boiler environment. The database provides centralized access to data and includes components and tools to enhance effective business decisions based on timely and accurate data.

Figure 9-53: Intertech/ATI's AWARE Software Home Screen.

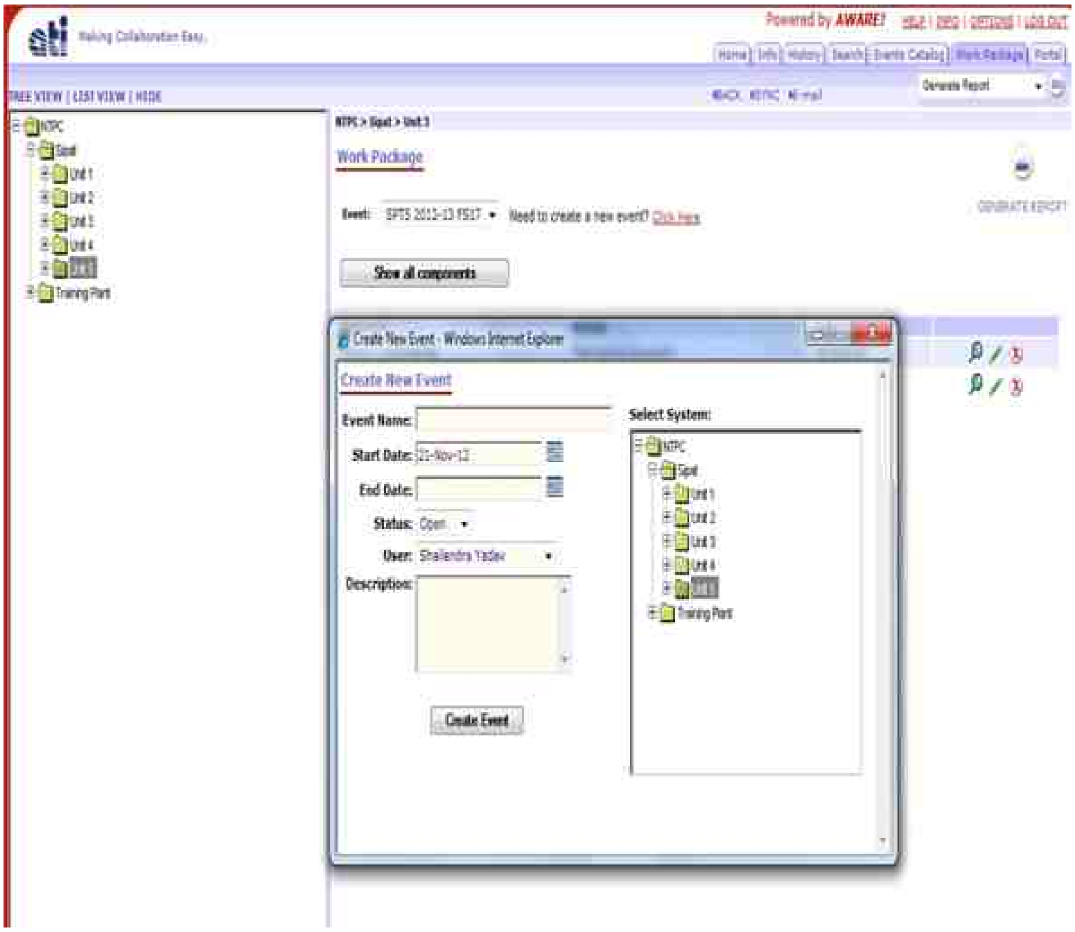


The Client Software: The database should be accompanied by a user-friendly Graphical User Interface (GUI) client that transforms the "raw" data housed in the database to information useful to people (Figure 9-53). The client must have a well-designed security structure to ensure proper working procedures and electronic signatures. It must be able to export and interact with other open programs such as Word and Excel. Its parent-child hierarchy must mimic the equipment hierarchy used with other programs (Maintenance Management System, Monitoring and Diagnostic tool, etc.) so that virtual data linkages may be formed for quick access (Figure 9-54) as follows:

Plant

- Unit (1,2,3, etc.)
  - Equipment (Boiler)
    - System (Reheater)
      - Sub-System (Pendant Reheater)
        - Component (Reheater Outlet Header)

Figure 9-54: Equipment Hierarchy (Partial) - Intertech/ATI's AWARE Software



Event: SPTS 2012-13 FS17 Need to create a new event? Click here

Event Name:

Start Date: 21-Nov-13

End Date:

Status: Open

User: Shailendra Yadav

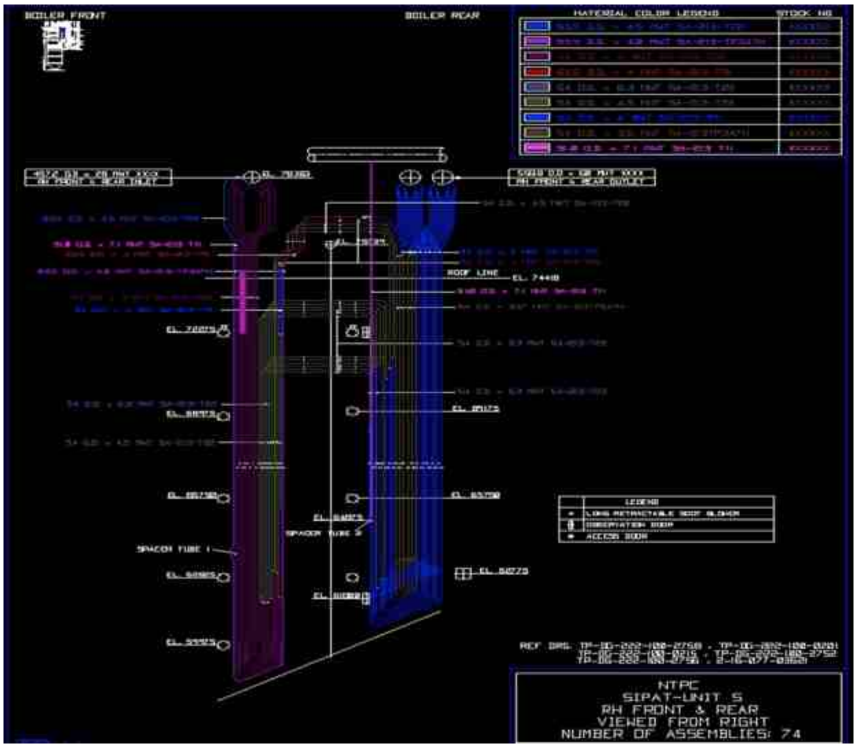
Description:

The client software must also be able to capture and define relevant information about any type of unit and the sub-elements of that unit down to the component level e.g. tube assembly and header (The plant hierarchy structure). The program must be able to select and view 2 and 3 dimensional scale models of the boiler and boiler-elements. This must be a "smart" visual portrait for ease of reference (Figure 9-55).

To support inspections and repairs, the client must be able to set the properties for points to be measured such as:

- The range(s) to be inspected
- Material types
- Distinguish between accumulative & de-cumulative damage mechanisms
- Inspection Methods
- The measure positions and intervals

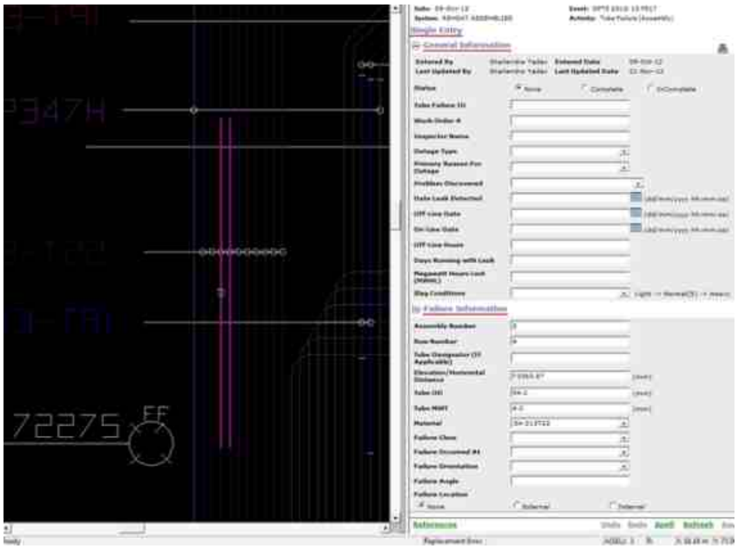
Figure 9-55: "Smart" Graphic Image - Intertech/ATI AWARE



It must be able to save all types of inspection data such as wall thickness, replica results, visual and other NDT reports. In addition, it must be able to validate new data entered by referencing historical trends and records. It must support the documentation of corrective actions that influence various inspection points and historical documentation of decisions made in previous outages. Further, for inspections the client software must be able to trend all quantifiable data and predict future tube wastage based on standard operating conditions. This capability must be on a tube-level since the rate of deterioration can vary widely. For repairs, it must be able to define and calculate the material usage per corrective action and store specific plant failure information and boiler operating statistics and information such as:

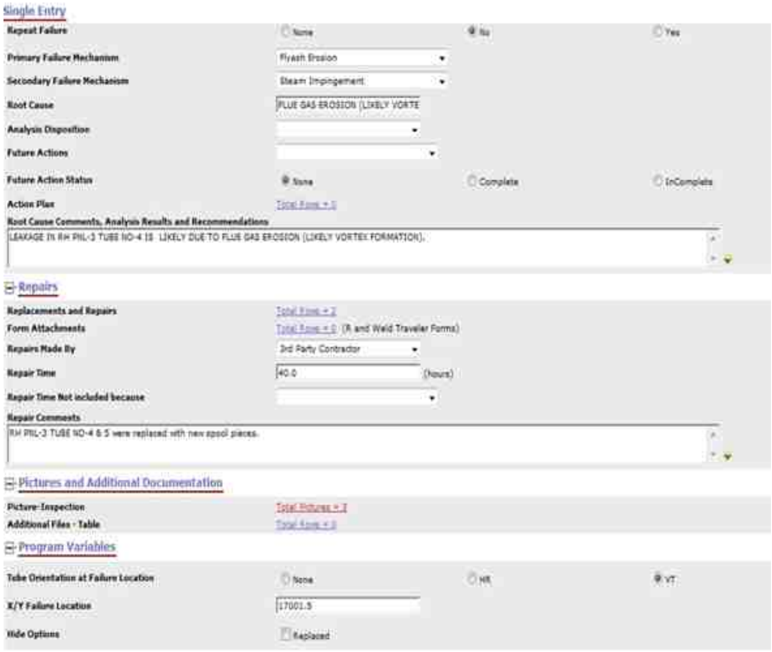
- Failure summary
- Unit statistics
- Consequential damages
- Sequence of events
- Outage and unit history
- Failure mechanism
- The causes i.e. contributory, direct and root
- Boiler and unit risk
- Observations
- Photos of the failure

Figure 9-56: Documentation of General and Failure Information – Intertech / ATI AWARE Software



The client software must support engineering analyses e.g. it can be linked to the Monitoring and Inspection Plan so that adjustment to the plan can be made based on the appearance of new suspected failure mechanisms or to overwrite inspection acceptance criterion. For outage planning and budgeting, it must be capable of capturing and quantifying future repair requirements and material usage (Figure 9-57).

Figure 9-57: Support for Engineering Analysis – Intertech/ATI AWARE



Single Entry

Repeat Failure	○ None	● No	○ Yes
Primary Failure Mechanism	Flyash Erosion		
Secondary Failure Mechanism	Steam Impingement		
Root Cause	FLUE GAS EROSION (LIKELY VORTE		
Analysis Disposition			
Future Actions			
Future Action Status	● None	○ Complete	○ InComplete
Action Plan	Total Rows = 0		

Root Cause Comments, Analysis Results and Recommendations

LEAKAGE IN RH PNL-3 TUBE NO-4 IS LIKELY DUE TO FLUE GAS EROSION (LIKELY VORTEX FORMATION).

Repairs

Replacements and Repairs	Total Rows = 2
Form Attachments	Total Rows = 0 (R and Weld Traveler Forms)
Repairs Made By	3rd Party Contractor
Repair Time	40.0 (hours)
Repair Time Not included because	

Repair Comments

RH PNL-3 TUBE NO-4 & 5 were replaced with new spool pieces.

Pictures and Additional Documentation

Picture-Inspection	Total Pictures = 3
Additional Files - Table	Total Rows = 0

Program Variables

Tube Orientation at Failure Location	○ None	○ HR	● VT
X/Y Failure Location	17001.5		
Hide Options	☐ Replaced		

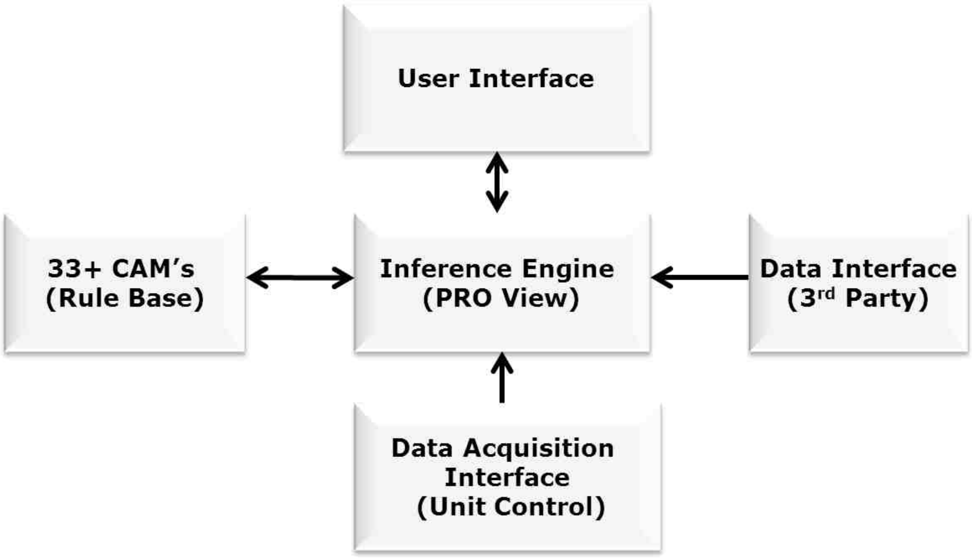
As can be seen, much functionality is recommended for any Monitoring and Inspection tool to be used in an effective program. Everything described supports a plan that is either corrective, meaning a failure has occurred or predictive in nature, meaning that damage has occurred and is measurable. Neither are ideal strategies, however. The ideal strategy and the TBM default are proactive because damage is not allowed to begin. However, the proactive strategy requires that precursors to damage mechanisms be measurable and measured by sensors. This is not possible for all damage mechanisms so a combination of proactive and predictive must be considered ideal. Carefully assessing and balancing the combination of proactive and predictive strategies is at the core of TBM. In the next section, key elements and attributes of the proactive Monitoring and Diagnostic (Unit In Service) software application are described.

Monitoring and Diagnostic (Unit in Service) Software

Introduction

Robust continuous monitoring and diagnostic software applications are still emerging in the market. Monitoring software with varying levels of functionality to serve multiple purposes has been in existence for several years. The primary focus of real-time software for use in TBM is to be proactive; the ability to diagnose conditions, utilizing a rule-base, before they become detrimental so that there is time to correct them (Figure 9-58).

Figure 9-58: Example of Rule-Based or Advanced Pattern Recognition System Modeling Capabilities – P&RO Solutions ProView

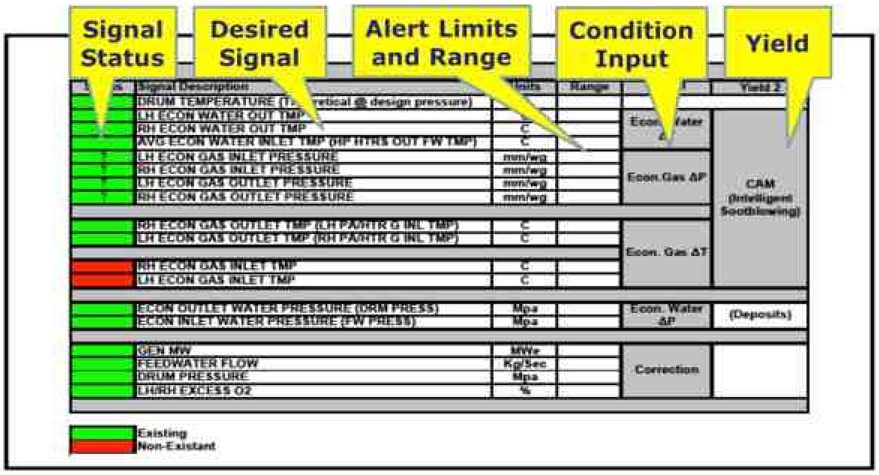


Computerized equipment condition monitoring and diagnostics requires that a large amount of input data be processed for use by people. This section addresses the functionality that users will find most helpful in continuous boiler monitoring and diagnostic software applications. Following the TBM Key Element and attribute format, the technical attributes of continuous condition monitoring and diagnostics software are presented next.

Technical Attributes

The software platform must be web-based or installed on a wide-area network. There should be no need for a separate database. The rules that diagnose target conditions must first be empirically modeled (Figure 9-59).

Figure 9-59: Example of "Intelligent" Sootblowing Software

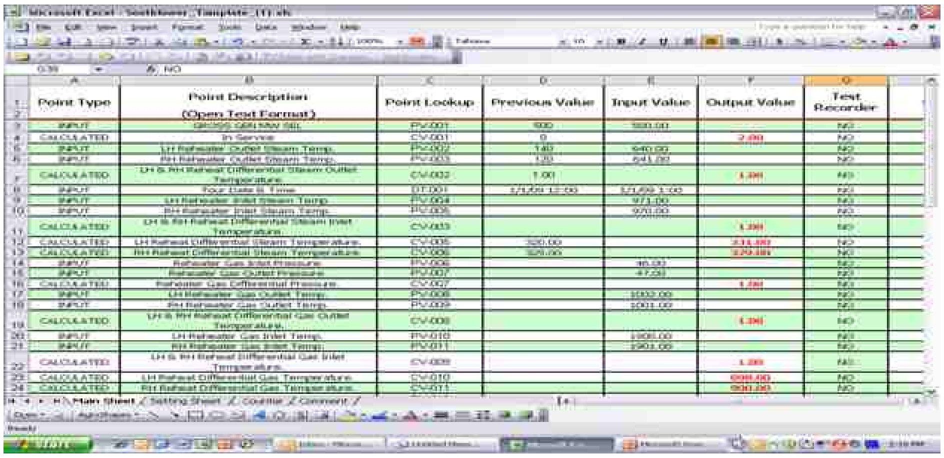


s	Signal Description	nits	Range		Yield 2
🟩	DRUM TEMPERATURE (T retical @ design pressure)				
🟩	LH ECON WATER OUT TMP			Econ /ater Δ	CAM (Intelligent Sootblowing)
🟩	RH ECON WATER OUT TMP	C			
🟩	AVG ECON WATER INLET TMP (HP HTRS OUT FW TMP)	C			
🟩	LH ECON GAS INLET PRESSURE	mm/wg		Econ.Gas ΔP	
🟩	RH ECON GAS INLET PRESSURE	mm/wg			
🟩	LH ECON GAS OUTLET PRESSURE	mm/wg			
🟩	RH ECON GAS OUTLET PRESSURE	mm/wg			
🟩	RH ECON GAS OUTLET TMP (LH PA/HTR G INL TMP)	C		Econ. Gas ΔT	
🟩	LH ECON GAS OUTLET TMP (RH PA/HTR G INL TMP)	C			
🟥	RH ECON GAS INLET TMP	C			
🟥	LH ECON GAS INLET TMP	C			
🟩	ECON OUTLET WATER PRESSURE (DRM PRESS)	Mpa		Econ. Water ΔP	(Deposits)
🟩	ECON INLET WATER PRESSURE (FW PRESS)	Mpa			
🟩	GEN MW	MWe		Correction	
🟩	FEEDWATER FLOW	Kg/Sec			
🟩	DRUM PRESSURE	Mpa			
🟩	LH/RH EXCESS O2	%			

🟩 Existing
🟥 Non-Existant

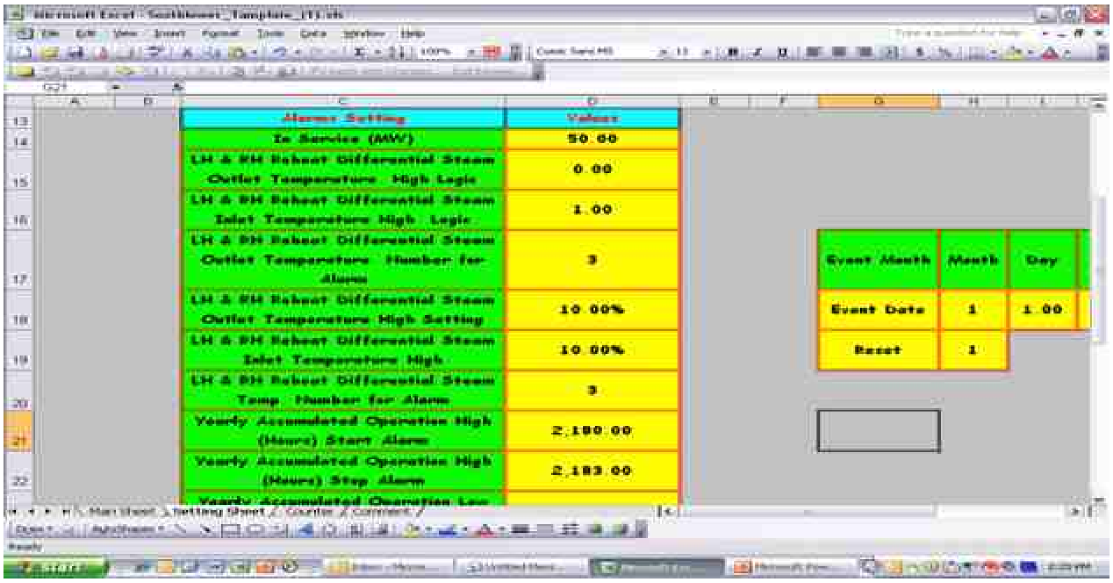
Selected sets of process and 3rd-Party data sources used in the models must be mapped from available enterprise infrastructure application software to the TBM monitoring and diagnostic software application (Figure 9-60).

Figure 9-60: P&RO Solutions ProView Diagnostics Software



	Point Type	Point Description (Open Text Format)	Point Lookup	Previous Value	Input Value	Output Value	Test Recorder
3	INPUT	GROSS GEN MW SEL	PV-001	500	500.00		NO
4	CALCULATED	In Service	CV-001	0		2.00	NO
5	INPUT	LH Reheater Outlet Steam Temp.	PV-002	140	640.00		NO
6	INPUT	RH Reheater Outlet Steam Temp.	PV-003	120	641.00		NO
7	CALCULATED	LH & RH Reheat Differential Steam Outlet Temperature.	CV-002	1.00		1.00	NO
8	INPUT	Your Date & Time	DT:001	1/1/09 12:00	1/1/09 1:00		NO
9	INPUT	LH Reheater Inlet Steam Temp.	PV-004		971.00		NO
10	INPUT	RH Reheater Inlet Steam Temp.	PV-005		970.00		NO
11	CALCULATED	LH & RH Reheat Differential Steam Inlet Temperature.	CV-003			1.00	NO
12	CALCULATED	LH Reheat Differential Steam Temperature.	CV-005	320.00		[illegible]	NO
13	CALCULATED	RH Reheat Differential Steam Temperature.	CV-006	325.00		[illegible]	NO
14	INPUT	Reheater Gas Inlet Pressure	PV-006		46.00		NO
15	INPUT	Reheater Gas Outlet Pressure	PV-007		47.00		NO
16	CALCULATED	Reheater Gas Differential Pressure	CV-007			1.00	NO
17	INPUT	LH Reheater Gas Outlet Temp.	PV-008		1002.00		NO
18	INPUT	RH Reheater Gas Outlet Temp.	PV-009		1001.00		NO
19	CALCULATED	LH & RH Reheat Differential Gas Outlet Temperature.	CV-008			1.00	NO
20	INPUT	LH Reheater Gas Inlet Temp.	PV-010		1900.00		NO
21	INPUT	RH Reheater Gas Inlet Temp.	PV-011		1901.00		NO
22	CALCULATED	LH & RH Reheat Differential Gas Inlet Temperature.	CV-009			1.00	NO
23	CALCULATED	LH Reheat Differential Gas Temperature.	CV-010			[illegible]	NO
24	CALCULATED	RH Reheat Differential Gas Temperature.	CV-011			[illegible]	NO

Figure 9-61: P&RO Solutions Diagnostics Software Showing Input Fields and Alert Limits

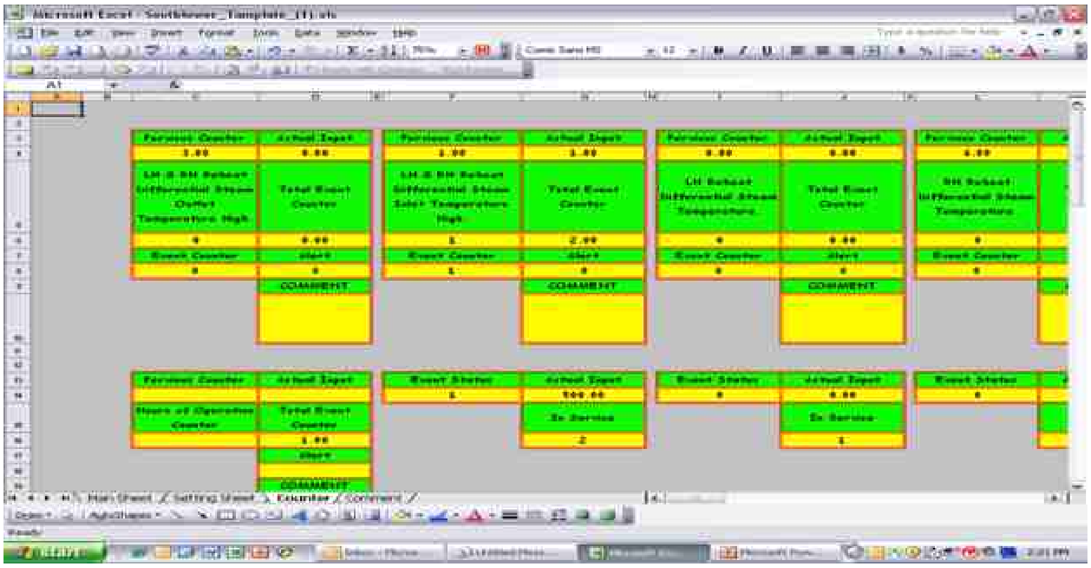


Alarm Setting	Values
In Service (MW)	50.00
LH & RH Reheat Differential Steam Outlet Temperature High Logic	0.00
LH & RH Reheat Differential Steam Inlet Temperature High Logic	1.00
LH & RH Reheat Differential Steam Outlet Temperature Number for Alarm	3
LH & RH Reheat Differential Steam Outlet Temperature High Setting	10.00%
LH & RH Reheat Differential Steam Inlet Temperature High	10.00%
LH & RH Reheat Differential Steam Temp Number for Alarm	3
Yearly Accumulated Operation High (Hours) Start Alarm	2,180.00
Yearly Accumulated Operation High (Hours) Stop Alarm	2,183.00
Yearly Accumulated Operation Low	

Event Month	Month	Day
Event Date	1	1.00
Reset	1	

A key software function, often overlooked is the ability to integrate and to measure the severity of excursion. The software capability should include the ability to accumulate the points of interest, duration and amplitude of the excursion as shown in Figure 9-62.

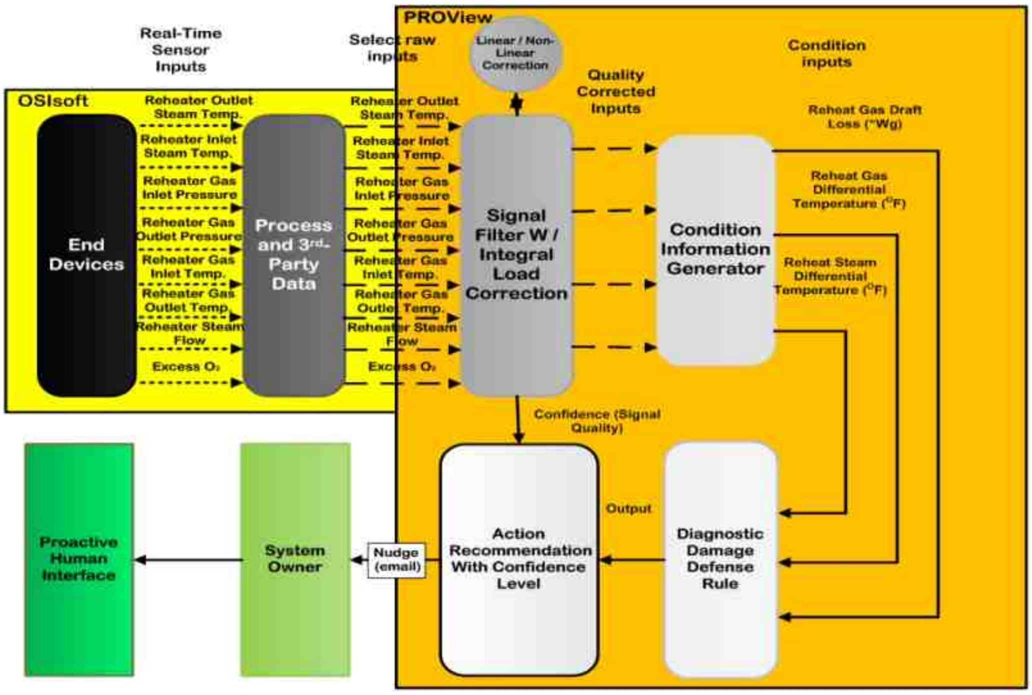
Figure 9-62: P&RO Solutions ProView Software



Functional Attributes

One principle that was adhered to whenever possible while developing TBM was to let the computer do the work. The functional attributes of the continuous monitoring and diagnostic tool should follow suit – convert data to information optimally useful in quick decision-making (Figure 9-63).

Figure 9-63: Functional diagram for continuous monitoring and diagnostics – P&RO Solutions ProView Software

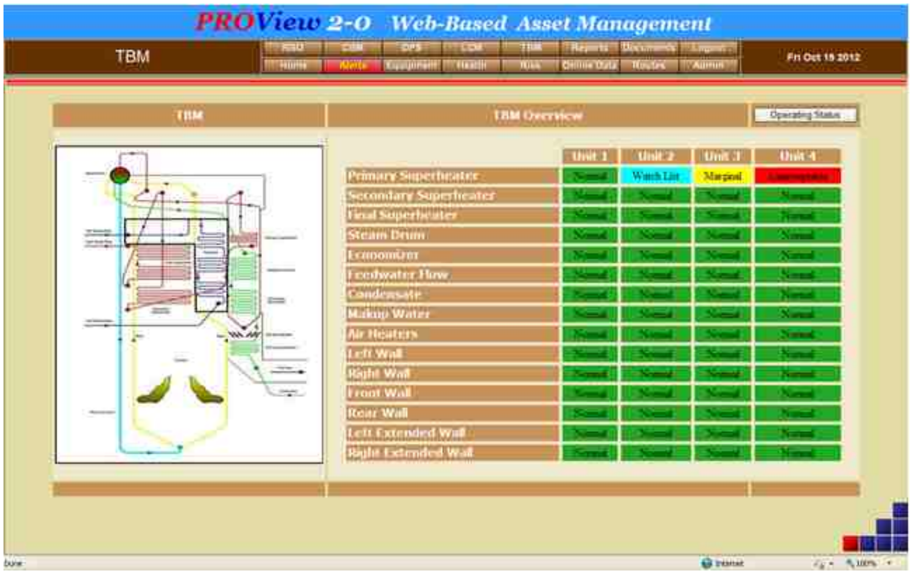


Providing "24/7" oversight and proactive notification to Operators and System Owners helps to eliminate damage mechanisms that eventually become boiler tube failures. This is done by monitoring individual or combinations of defined damage precursors, diagnosing through Boolean rule logic when select inputs exceed acceptable limits and "pushing" notification of the unacceptable condition to responsible personnel.

By clicking on the "unacceptable" cell, the end user can view operating data at the component level and quickly learn that Unit 4's Reheater has higher than recommended tube metal temperature. Long-Term Overheating and Creep Fatigue is the Damage Mechanism being monitored in this instant (Figure 9-65).

The following P&RO Solutions software screen show was designed to provide quick notification of an unacceptable condition that exists in a primary superheater.

Figure 9-64: The TBM Unit Status Screen



PROView 2-0 Web-Based Asset Management

TBM

Fri Oct 19 2012

TBM | TBM Overview | Operating Status

	Unit 1	Unit 2	Unit 3	Unit 4
Primary Superheater	Normal	Watch List	Marginal	[illegible]
Secondary Superheater	Normal	Normal	Normal	Normal
Final Superheater	Normal	Normal	Normal	Normal
Steam Drum	Normal	Normal	Normal	Normal
Economizer	Normal	Normal	Normal	Normal
Feedwater Flow	Normal	Normal	Normal	Normal
Condensate	Normal	Normal	Normal	Normal
Makeup Water	Normal	Normal	Normal	Normal
Air Heaters	Normal	Normal	Normal	Normal
Left Wall	Normal	Normal	Normal	Normal
Right Wall	Normal	Normal	Normal	Normal
Front Wall	Normal	Normal	Normal	Normal
Rear Wall	Normal	Normal	Normal	Normal
Left Extended Wall	Normal	Normal	Normal	Normal
Right Extended Wall	Normal	Normal	Normal	Normal

Figure 9-65: TBM Component Status Screen– P&RO Solutions ProView Software

PROView 2-0 Web-Based Asset Management

Home Page

Mon Aug 13 2012

PRO Demo Database | Current Plant Status: 03-01-2012 14:00

	Unit 1	Unit 2	Unit 3	Unit 4
REHEATER METAL TEMPERATURE 1	[illegible]	[illegible]	[illegible]	[illegible]
REHEATER METAL TEMPERATURE 2	[illegible]	[illegible]	[illegible]	[illegible]
REHEATER METAL TEMPERATURE 3	[illegible]	[illegible]	[illegible]	[illegible]
REHEATER METAL TEMPERATURE 4	[illegible]	[illegible]	[illegible]	[illegible]
REHEATER METAL TEMPERATURE 5	[illegible]	[illegible]	[illegible]	[illegible]
REHEATER METAL TEMPERATURE 6	[illegible]	[illegible]	[illegible]	[illegible]
REHEATER METAL TEMPERATURE 7	[illegible]	[illegible]	[illegible]	[illegible]
FEEDWATER TEMPERATURE	[illegible]	[illegible]	[illegible]	[illegible]
HOT REHEAT STEAM TEMPERATURE	[illegible]	[illegible]	[illegible]	[illegible]

The user can investigate the problem quickly and thoroughly because the application is linked to other related data sources so that more detail may be gathered. The user has enough knowledge to intervene, hopefully before damage is initiated or propagated.

Individual inputs can be viewed to characterize indications at the sub-component level as seen in the following P&RO Solutions ProView Software.

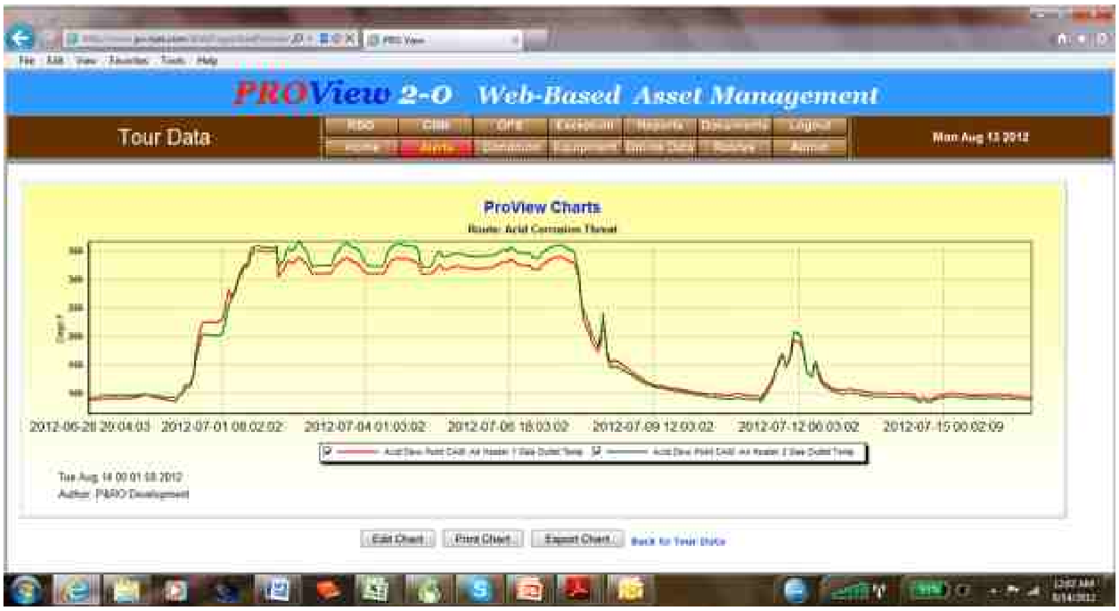
Figure 9-66: The TBM Diagnostic Input Screen

A round parameter screen that should be of concern to the end user has been "Called Out". In the following illustration, it appears as though average "Air Heater Gas Outlet Temperature" is low for the unit load and that the Air Heater may have a problem.

Figure 9-67: The "Round" Parameter Screen

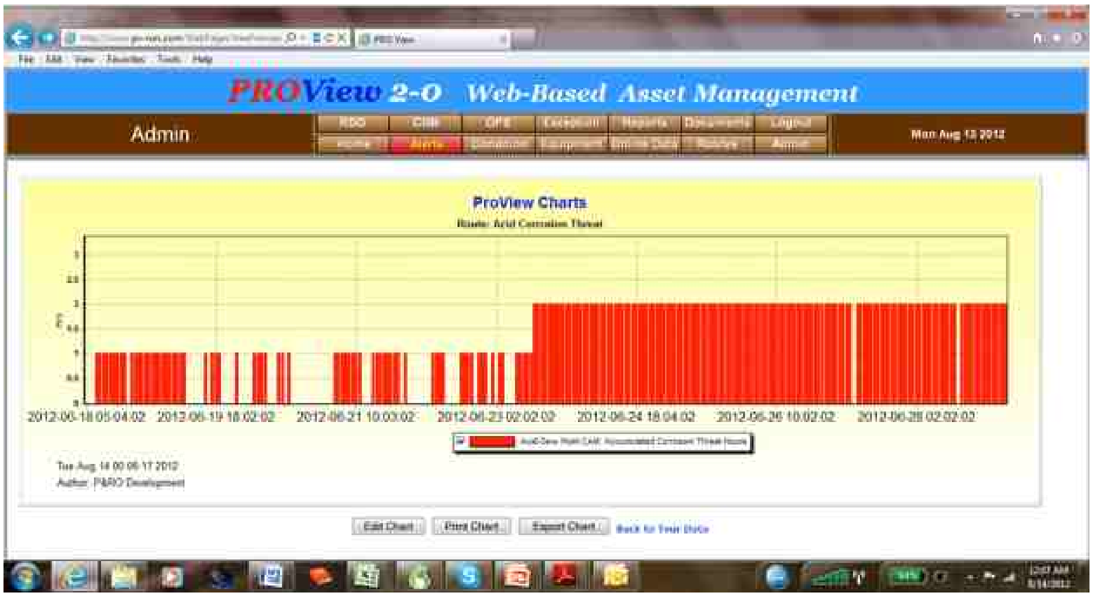
In Figure 9-68, another CAM is monitoring a select group of points for conditions that could cause Acid Dew Point Corrosion in the boilers convective section. The end user is viewing input groups known as a "Round".

Figure 9-68: Complex Trend Screen



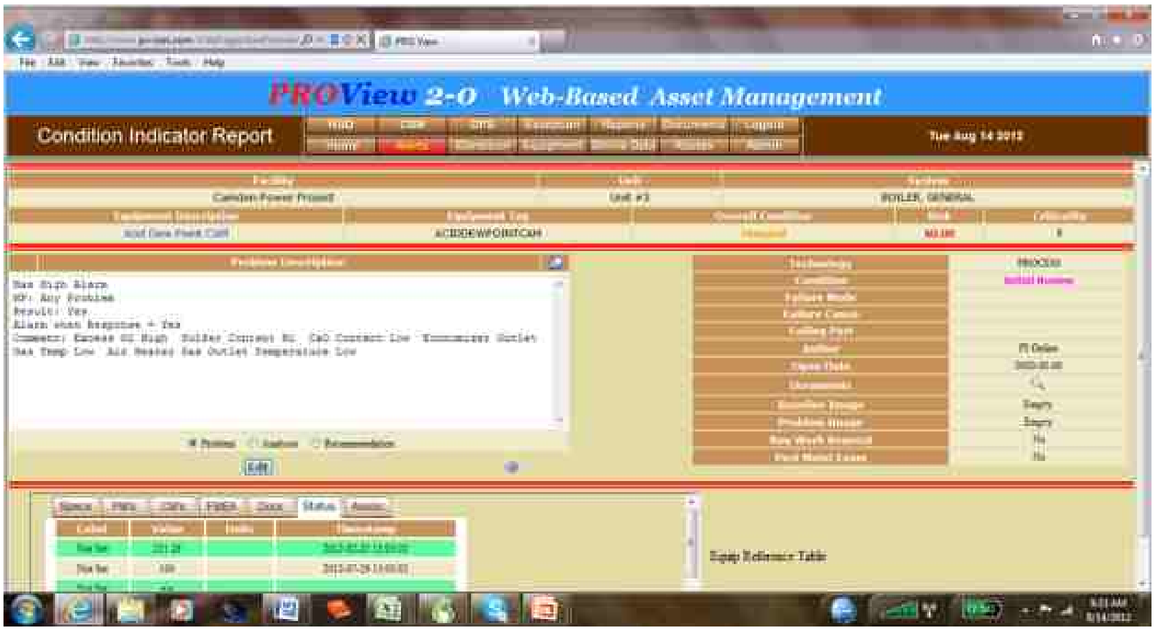
The user may gain insight by viewing trend parameters of concern over time to help draw conclusions and expedite decisions to correct the anomaly before damage can occur. Trends may be configured many different ways with flexibility that is adaptable to almost any situation.

Figure 9-69: Web based Information Trending



A pre-programmed notification that is automatically dispatched can be sent via email, texts or anywhere and anytime to notify others of pending issues.

Figure 9-70: Notifications Screen



The reliability risk engine simplifies the evaluation and prioritization of risk. The risk models can be adapted to changes in unit mission or objectives by the end user.

Figure 9-71: Risk Engine

Below is a screen showing probability and consequence expressed in financial terms so that they may be better tracked to organizational goals.

Figure 9-72: Financial Risk Impact

Plant Safety Considerations 10.0

10.0 Plant Safety Considerations

SUMMARY

Safety is an area that always needs attention and continuous improvement. The consequences of injuries in the workplace is just too great to not give it equal importance as cost, quality, production and all other areas of focus in a power plant. This section provides information on best practices being used in power plants that have invested in attempting to reach world-class performance in the area of safety. In Part 1, the importance of establishing a vision and mission for safety is emphasized. Part 2 provides a suggested set of safety guiding principles that cover safety comprehensively. Part 3 emphasizes the absolute necessity for holding management fully accountable for effective processes, programs and results. Part 4 speaks to the necessity of having executive management, including the CEO, actively involved in the safety effort. Part 5 addresses the need for effective safety programs and the concern for them becoming stale and perfunctory. Part 6 covers the safety pyramid concept and the importance of including near misses, unsafe acts and unsafe conditions. Part 7 is key in that it gives a comprehensive process framework for managing safety. Part 8 encourages the use of a CEO forum for all serious injuries. Part 9 covers the concept of having a site wide Safety Steering Team led by the site head. And finally, part 10 speaks to recognizing the target audience for the safety message. What works for the CEO may not motivate first line employees.

It is hoped that by implementing these best practices Indian utilities can see fundamental change and continuous improvement in the area of safety.

Introduction

There is nothing more important than a sincere commitment to safety. Safety is a value that cannot be compromised. During the 21st century, with vast communications resources and international linkage there is no excuse for any location in the world having less than excellent safety results. The days of taking more risks with fewer rules and guidelines are no longer acceptable. However, excellent safety results are not achieved by more rules, regulations and guidelines. These are important, but they are not where good safety processes start and without good processes you are doomed to failure or at least having very inconsistent results.

This chapter attempts to provide some of the best practices that are followed in the U.S. power industry.

Best Practices

1. Establish vision and mission statements for safety. As a refresher, a vision is a future state one wishes to obtain. A mission is the things one does to achieve the vision. An example of a vision might be:

   ABC Company operates the safest power plants in India through the use of safety processes and having a culture that recognizes that safety is a fundamental value and a moral responsibility.

   And an example of a mission might be:

   We work to create the proper safety culture through development of the various processes for safety, we communicate for safety and we maintain a highly motivated workforce with the proper regard for safety. We recognize that high morale levels along with the personal responsibility are necessary to obtain the safety results we must have.

2. Establish guiding principles, communicate them widely and live by them. A set of guiding principles used by a leading utility in the U.S. includes:

   - Everyone is responsible for safety.
   - We look out for each other.
   - Safety will be planned into our work.
   - All injuries are preventable.
   - Management is accountable for preventing injuries.
   - Employees must be trained to work safely.
   - Working safely is a condition of employment.
   - Safety performance will be measured.
   - All deficiencies must be resolved.
   - React to incidents, not just injuries.
   - Off the job safety is as important as on the job safety.
   - It is good business to prevent injuries.
   - We will comply with all occupational health and safety regulations.

   Once these guiding principles are in place then everyone needs to be very aware of them and management needs to stand in front of the workforce and communicate them while expressing strong personal commitment for seeing that they are followed.

   These guiding principles need to be displayed throughout all company locations.

3. Assure that management is held accountable for excellent safety results. The expression "if you cannot manage safety, you cannot manage" is not too strong and has often been used

in the U.S. No performance evaluation should be considered complete without addressing safety and having it as a Key Results Area (KRA). Management must confront poor safety performance on the part of all employees and there must be very severe consequences for having a careless disregard for safety.

4. Management commitment must come from the highest levels of management. If it is not spoken to by the CEO then much of the effectiveness of the safety effort is eroded.

5. Good safety programs are a good way to raise awareness and even change the culture. You must always be on the lookout for very good programs to implement. Some programs can be imbedded and can be part of your company from now on. Other programs can out lie their usefulness and even become a negative. A good rotation of programs such as Dupont's STOP program is a good example. Use it to raise the activity related to observations but do not institutionalize it. Find another program to raise awareness. STOP can become very perfunctory.

   A good program that can raise awareness and break down barriers is the “Tell Me” program used by a leading U.S. utility. This program is one that can be retained forever due to its simplicity. Here is a description of that program:

There is a natural reluctance to correcting someone if you see them doing something unsafe. This is caused by a desire to avoid conflict, maybe a previous encounter by someone who go an angry response, a natural deference to more senior members of a team or several other reasons.

The consequences of injuries are just too severe and wrong to have an atmosphere where everyone is not looking out for everybody. Hence the “Tell Me” program. They called it the “It’s OK” program.

Please “tell me” if you see me doing something unsafe or that violates our safety guidelines. Please “tell me” if you have had an injury or near miss or know of unsafe condition that can prevent me from being injured. I promise to look out for you and I want you to look out for me. Together we can be injury free!

By signing this card and wearing the “Tell Me” sticker I am committed to 100 percent conformance and “0” injuries.

Signature: ____________________ Date: __________________

Name: ______________________

6. Utilize the safety pyramid that escalates to a fatality at the top.

   This pyramid is widely used throughout the world but what some people miss is that the base is not minor injuries. The base is near misses, unsafe acts and conditions. This is the real gold mine of information that can prevent injuries. The challenge next becomes getting employees to report these, particularly near misses and unsafe acts. Employees should not feel intimidated for reporting.

7. A leading U.S. utility recognized that implementing robust safety procedures could only attain good safety results. This utility identified six key processes in the area of safety. These are:
   - Awareness
   - Measurement
   - Recognition
   - Training
   - Investigation
   - Assessment

Corporate wide teams were put into place to determine the details of each of these processes. The specifics of these processes could look like the following though each company should take the time to assign teams and design these processes for their specific company:

- Safety Awareness
  - Safety Guiding Principles
  - Safety Committees
  - Safety Steering teams
    - o Proper attendees
    - o Defined agenda
    - o Defined time
    - o Full participation
    - o Working group
    - o Discuss issues
    - o Discuss inspections
    - o Allocate budget
    - o Develop action items
    - o Make assignments
  - Effective communications
  - Safety KRA in performance management

- Safety Measurement
  - Standard reporting system
  - Well defined measures
  - Communications of results
  - Convert data to information
  - Measures used in performance evaluations
  - Measures used in incentive goals

- Safety Recognition
  - Standard format
  - Timely
  - Management visibility
  - Informal and formal
  - Avoid unintended negatives
  - Incentive plan
  - Recognize outstanding behavior immediately
  - Recognize teams
  - Create budget

- Safety Training
  - Regulatory/Required
  - Technical
  - Soft skills
  - Behavior based
  - Emergency response
    - Medical
    - Fire
    - Environmental
  - Define frequency/schedule
  - Define content
  - Management and employee
- Accident Investigation
  - Standard format
  - Investigate all events

  - Utilize root cause analysis as appropriate
  - Act on findings
  - Understand error types
    - Rule based
    - Knowledge based
    - Skill based
  - Utilize teams with right mix
  - Timely
  - Utilize disciplinary action as appropriate

- Safety Assessment
  - Risk Assessment (added 10/8/10)
    - Job Safety and Health Analysis
    - Define acceptable risk
    - Employees surveys/feedback
  - Internal and external audits
  - Various levels of assessments/audits
    - Personal
    - Team
    - Station
    - Department
    - Corporate
  - Act on findings with budget and schedule
  - Results included in management performance evaluations
  - Communicate results

8. CEO review forum for serious injuries

   One utility proposed the following:

   To create added awareness and seriousness to accident prevention, it is proposed to establish a CEO review forum. This forum will review all serious injuries with the CEO leading this meeting. The concept is:

   In case a serious injury occurs, a committee assembled by the CEO will investigate the injury or dangerous occurrence and submit the findings to all concerned along with the recommendations to prevent such events from occurring in the future. The time line for completing the detailed investigation and finalizing the recommendations will be one week. The report shall be reviewed by the CEO in a meeting or through video conferencing with all the concerned including the injured party and his immediate supervisor.

9. Create a site safety steering team, led by the site head, with the suggested following agenda:

    SSC Standing Agenda

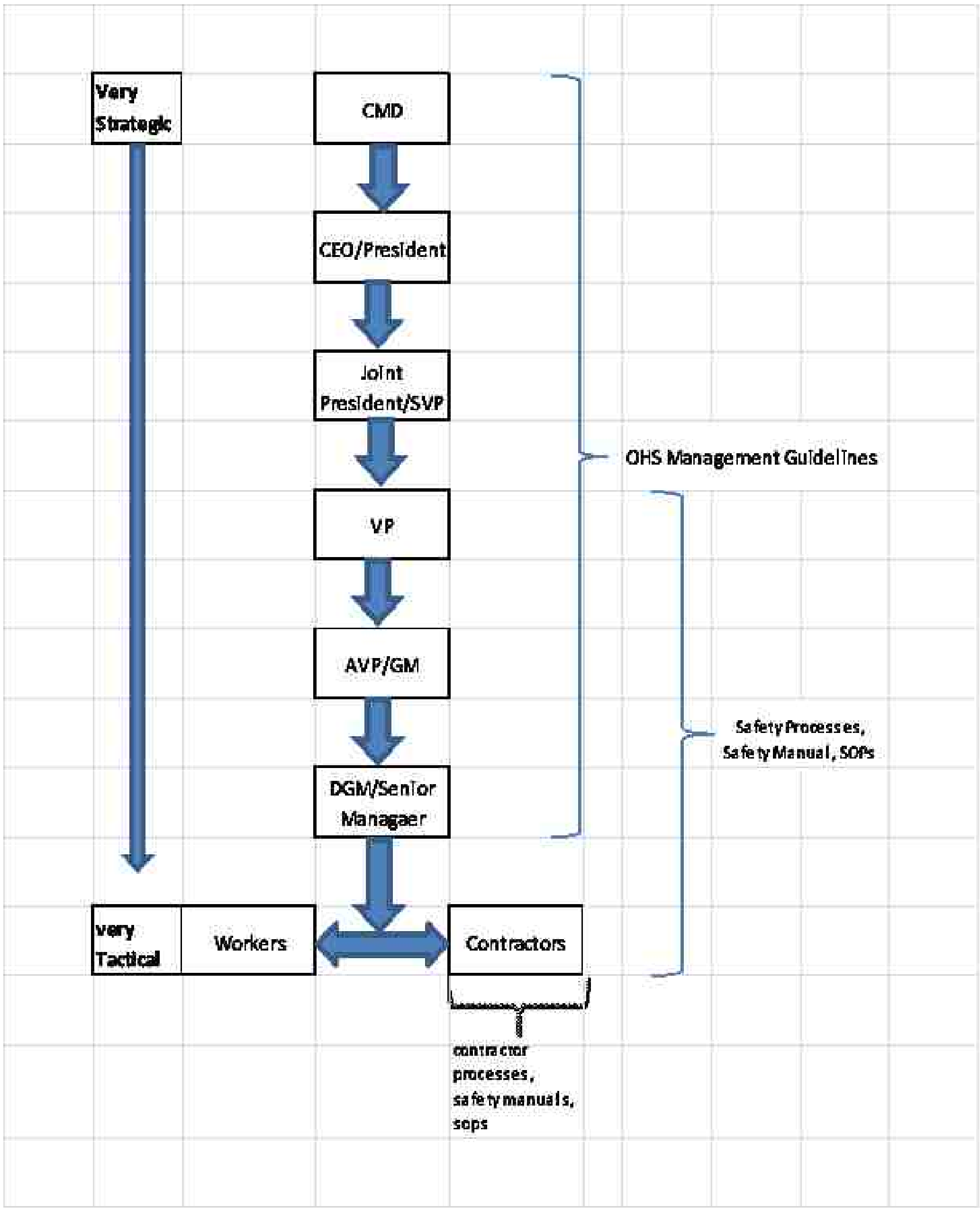
    1. Safety Talk ....5 minutes
    2. Review of injuries for the last month.........................10 minutes
    3. Review safety measures for the last month.....................10 minutes
    4. Review Medical Department measures for the last month.........10 minutes
    5. Identify the safety focus for the next month...................5 minutes
    6. Discussion of contractor safety activities....................20 minutes
    7. Special agenda topics (if any) ....15 minutes
    8. Roundtable ....30 minutes
    9. Report on action items and make assignments ....15 minutes
    10. Adjourn

Note: This meeting is scheduled for one and one half hours. We must guard against extending this meeting beyond that or it will lose its effectiveness and will unnecessarily tie up very busy people. There are basically two types of meetings. There are problem solving meetings with attendance limited to a small group of essential people. If this meeting has too many people in it, it becomes ineffective. There are also information transfer meetings where attendance can be much larger since the goal is to provide information and asses where we are. The site safety team meeting is this type of meeting so it must not get bogged down in problem solving.

10. Recognize the target audience for various safety activities and processes.

Figure 10-1 was developed by one leading utility for the modeling of safety activities. Obviously higher management is more strategic and employees on the front line are much more tactical in nature. Therefore different activities and types of information are required.

Figure 10-1: Target Audience for Various Safety Activities and Processes



Acronyms 11.0

11.0 Acronyms

ACE	Accelerating Change towards Excellence
AEP	American Electric Power
AKA	also known as
AMS	Asset Management System
APC	air preheater coils
APH	air preheater
APR	Advanced Pattern Recognition
ASME	American Society of Mechanical Engineers
ASME	American Society of Mechanical Engineers
ASNT	American Society of Non Destructive Testing
ASTM	American Standard for Testing of Materials
ATI	Aware Technology International
ATP	Adenosine Tri-Phosphate
AVT	All Volatile water Treatment
BC	Brine Concentrator
BCP	Boiler Circulating Pump
BEP	Best Efficiency Point
BFP	Boiler Feed Pump
BFPT	Boiler Feed Pump Turbine
BTFD	Boiler Tube Failure Defense
BTU	British Thermal Unit
CAM	Component Analysis Method
CAVT	Cold Air Velocity Test
CBM	Condition Based Maintenance
CBO	Condition-Based Overhaul
CEMS	Continuous Emissions Monitoring System
CenPEEP	Centre for Power Efficiency & Environmental Protection
CF	Corrosion Fatigue
CI	critical indicators
CII-GBC	Confederation of Indian Industries – Green Building Center

CI-SP	Critical Indicator-Set Point
CM	Corrective Maintenance
CMMS	Computerized Maintenance Management System
COC	Cycles of Concentration
CTI	Cooling Tower Institute
CW	circulating water
DA	Deaerator
D-BASE	an object oriented program language
DCTTD	Drain Cooler Terminal Temperature Difference
DMW	Dissimilar Metal Weld
DNB	Departure from Nucleate Boiling
DP	differential pressure
DT	differential temperature
EFOR	Equivalent Forced Outage Rate
EFOR-d	Forced Outage Rate – Demand Periods Equivalent
EID	equipment identification
EIN	equipment identification number
EPRI	Electric Power Research Institute
FAC	Flow Accelerated Corrosion
FD	forced draft
FEGT	furnace exit gas temperature
FGD	Flue Gas Desulfurization
FMEA	Failure Mode Effects Analysis
FMECA	Failure Mode Effects Criticality Analysis
GAR	Generation Availability Report
GDP	Gross Domestic Product
GTCHR	Gross Turbine Cycle Heat Rate
GUI	graphical user index
HAZ	Heat Affected Zone
HEDP	Hydroxy Ethylidene Diphosphonic Acid
HEI	Heat Exchanger Institute
HGI	Hardgrove Grindability Index
HHV	high heating value

HP	high pressure
HPES	Human Performance Evaluation System
HPFT	High Pressure Flash Tank
HRSG	Heat Recovery Steam Generator
HV	Vickers Pyramid Number (hardness number for materials)
HVT	High Velocity Thermocouple
I&C	instrumentation & control
IAPWS	International Association for the Properties of Water and Steam
ID	inside diameter
IP	intermediate pressure
IPI	Inspection Prioritization Index
IPT	Intermediate Pressure Turbine
IRT	Infra-Red Thermography
ITD	Initial Temperature Difference
KCAL	kilo calorie
KPI	Key Performance Indicator
KRA	Key Results Area
LIBS	Laser Induced Breakdown Spectroscopy
LP	low pressure
LPT	low pressure turbine
LSI	Langelier Saturation Index
LTH	low temperature heater
MAF	Moisture and Ash Free
MCR	Maximum Continuous Rating
mg/kg	milligram per kilogram
MMHO	micro mho
mmWC	Millimeter Water Column (?P)
MT	Magnetic Particle Testing
MTBF	Mean Time Between Failure
MTTI	Mean Time to Inspect
MTTR	Mean Time To Repair
NDE	Non Destructive Examination
NERC	North American Energy Reliability Corporation

NPT	National Pipe Thread
NTPC	National Thermal Power Corporation
OA	Over Fire Air
OD	Outside Diameter
ODBC	Open Data Base Connectivity
OEM	Original Equipment Manufacturer
OT	Oxygenated Treatment
OUC	Orlando Utilities Commission
P&RO	Performance & Reliability Optimization, INC.
PAM	Proactive Maintenance
PAPH	Primary Air Preheater
pc-GAR	Generation Availability Report (PC Based)
pc-GAR-MT	Generation Availability Report (PC Based): with Mean Time Between Failures
PDM	Predictive Maintenance
PEPSE	Performance Evaluation for Power Systems Efficiency
PGNAA	Prompt Gamma Neutron Activation Analysis
PGP	Performance of Generating Plant
PID	Process Instrumentation Diagram
PM	Preventive Maintenance
PPB	Parts Per Billion
PPM	Parts Per Million
PPT	Parts Per Trillion
PRO	Plant Reliability Optimization
PT	DYE Penetrant Testing
PTC	Performance Test Code (ASME)
PTZ	Phase Transition Zone
R&D	research & development
RB	Reliability Based
RBO	Reliability Based Optimization
RC	root cause
RCA	root cause analysis
RCFA	root cause failure analysis
RCM	Reliability-Centered Maintenance

REAP	Risk Evaluation and Prioritization
RH	reheat
RLU	Relative Light Units
RO	Reverse Osmosis
RPR	run, repair, replace
RTD	Resistance Temperature Device
SAP	Commercial Maintenance Management Software
SAPH	Secondary Air Preheater
SCC	Stress Corrosion Cracking
SEM	Scanning Electron Microscope
SG	Steam Generator
SH	Superheat (Superheater)
SJAE	Steam Jet Air Ejector
SME	Subject Matter Expert
SP	Set-Point
SPE	Solid Particle Erosion
SQL	Structure Query Language
SRCM	Streamlined Reliability Centered Maintenance
TBF	time between failure
TBM	Targeted Boiler Management
TDS	Total Dissolved Solids
TFD	Thermal Fatigue Damage
TTF	time to failure
TTI	time to inspect
TTR	time to repair
TVA	Tennessee Valley Authority
UMATS	Utility Mercury and Air Toxic Standards
USAID	United States Agency for International Development
WEC	World Energy Council
WO	work order
ZLD	Zero Liquid Discharge

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12.0 References

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