Routine Maintenance of Electric Generating Stations

TENNESSEE VALLEY AUTHORITY

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Contents

Executive Summary

The Tennessee Valley Authority (TVA) has more than 65 years of experience in maintaining electricity-generating units with a wide range of unit size and technologies.

This report examines TVA's maintenance philosophy and highlights specific TVA and industry routine maintenance activities. TVA and utility maintenance practices have as their goal unit reliability and availability and safe working conditions. This report presents maintenance case studies including:

- Cyclone replacements (at least 300 replaced industrywide [43 percent]).
- Draft system replacements (at least 79 replacements of forced-draft systems identified in a sample of 151 boilers [52 percent]).
- Reheater replacements (231 in a sample of 190 generating units [121 percent - some units had multiple replacements]).
- Economizer replacements (98 replacement projects identified in a sample of 202 generating units [49 percent]).

A large number of variables affect unit components' useful lives and dictate varying maintenance responses. These responses range from simply lubricating equipment to replacing components with improved materials to lessen component degradation and downtime. TVA's analyses indicate that component replacement does not occur at a certain age but varies widely, both within the TVA system and elsewhere in the industry.

The case studies presented herein are only illustrative of the broad range of maintenance, repair, and replacement activities necessary to ensure safe and reliable production of electric power from coal-fired units. They do, however, provide insights into commonly encountered failure mechanisms and the advancements in assessment and repair techniques that have occurred over the last three decades.

Introduction

The Tennessee Valley Authority (TVA) has more than 65 years of experience in maintaining various kinds of generating technologies.

A steam electricity-generating unit is a complicated machine consisting of thousands of separate parts and components that must be operated together in an integrated fashion to produce electricity. Like any complex mechanical system, an electricity-generating unit may suffer impaired performance caused by defects in design or manufacture, extreme operating conditions, or catastrophic failure. This impaired performance affects the economic performance of a unit and employee safety. In addition, it negatively impacts the ability to supply adequate and reliable electric energy to the public. To complicate matters, the unit's component parts are subject to different operating conditions and deteriorate at different rates. To ensure reliable integration and operation of all of these parts, an active maintenance program is necessary.

The Tennessee Valley Authority (TVA) has more than 65 years of experience in maintaining various kinds of power-generating technologies. In the early 1930s, TVA began operating and maintaining hydroelectric units. When the public's demand for electricity exceeded the region's hydroelectric generation potential, TVA turned to coal-fired steam generating units. Output from its hydroelectric and coal-fired units was later supplemented by generation from nuclear units. Whatever the choice of fuel or generating technology, maintenance has been and continues to be the key to reliable operation of a unit throughout its useful life.

In a 1972 report, two TVA power-system managers, T. H. Gladney and H. S. Fox, described TVA's maintenance experiences to date and its maintenance philosophy. Maintenance practices and techniques have improved since then, with better analytical tools and more experience, but the maintenance philosophy has remained unchanged for more than 25 years. TVA and other power-system operators try to attain and maintain the highest practical availability and reliability of generating assets while taking into account safety and economic and financial considerations. Only through careful maintenance of generating assets can the public's need for electric energy be reliably and safely met.

This report builds on the TVA maintenance activities documented in the earlier Gladney and Fox work. First, information about TVA's power system is provided. The report then discusses the life of a generating unit, the utility obligation to serve, and overall maintenance concepts in order to provide the fuller context in which maintenance decisions are made. This is followed by several case studies of specific maintenance projects and information about the frequency of similar maintenance activities on the TVA system and elsewhere.

TVA's Electric Power System

TVA is an agency and instrumentality of the United States created by the Tennessee Valley Authority Act of 1933. Congress has tasked TVA with the development and conservation of the resources of the Tennessee Valley region in order to foster the region's economic and social well-being. One component of TVA's regional resource development program is the generation, transmission, and sale of electric power. TVA's power system now serves approximately 8 million people in parts of seven states.

Throughout its history, TVA has championed the evolution of electricity-generating technologies to improve efficiency and reliability and to reduce costs.

Generation sources currently operated by TVA include 11 coal-fired power plants, 29 hydroelectric plants, 4 gas-turbine plants, 1 hydro pumped-storage facility, and 3 nuclear plants. TVA's 11 coal-fired power plants consist of 59 units, which are located in Alabama, Kentucky, and Tennessee. These units represent approximately 60 percent of the installed generating capacity on the TVA system.

TVA's oldest active coal-fired unit was placed into service in late 1951; the newest unit was placed into service in 1989. Four of the units are supercritical units. The unit boilers are a diverse mix of burner types and configurations: 26 are tangentially fired; 24 are wall-fired; 2 are cell burners; 6 are cyclones; and 1 is atmospheric fluidized-bed combustion. Unit sizes range from 125 MWs to 1,300 MWs (nameplate capacities). These boiler types and sizes are typical for more than 90 percent of the United States coal-fired boiler fleet. All of the boilers originally burned medium- to high-sulfur eastern coals, but a number of them currently burn coal blends consisting of low-sulfur western and medium- or high-sulfur eastern coals. TVA's nominal fossil fuel-fired capacity is now 19,917 MWs.

TVA is widely recognized as one of the leaders in the utility industry. Throughout its history, TVA has championed the evolution of electricity-generating technologies to improve efficiency and reliability and to reduce costs. Since the 1960s many of the major step increases in the size and economic performance of coal-fired generating plants have been taken by TVA. These steps included the construction and operation of:

- Gallatin Unit 1 - first 300 MW tangentially fired unit in 1956;
- Widow's Creek Unit 7 - first 500 MW tangentially fired unit in 1961;
- Colbert Unit 5 - first 500 MW wall-fired unit in 1965;
- Paradise Unit 1 - first 700 MW unit in 1963;
- Bull Run - first 900 MW unit in 1967;
- Paradise Unit 3 - first 1100 MW unit in 1970;
- Cumberland Unit 1 - first 1300 MW unit in 1973; and
- Shawnee Unit 10 - first utility-scale (160 MW) atmospheric fluidized-bed combustion unit in 1989.

As Gladney and Fox stated, these units *". . . represented the largest units the turbogenerator and steam-generator manufacturers were capable of designing and building; consequently, maintenance problems associated with prototype units were faced during the entire period."*

In its 1955 Annual Report to the President and Congress, TVA observed:

> *Because of the size of the TVA power system and its region-wide integration, TVA has been able to take advantage of the economies of "bigness" and to stimulate advances in steam-plant technology. Turbogenerators of unprecedented capacity and greater efficiency have been purchased in multiple units of 2 to 12. As a result, the new TVA steam plants have made excellent field laboratories for the manufacturers, providing an opportunity for inspecting and testing a whole series of machines under operating conditions. The later machines in each series could be improved from the experience with earlier installations.*

Many of the maintenance practices developed by TVA on these prototype units therefore became the practices that were adopted and refined by others in the industry.

Today, many of TVA's generating units are among the top performers in the country, ranking in the top decile in efficiency and reliability.

The Integrated Steam Electric Generating Unit

A typical steam driven electricity-generating unit is a complex assembly of off-the-shelf components and custom-engineered equipment. Steam: Its Generation and Use (40th edition 1992) by Babcock and Wilcox, and Combustion Fossil Power (4th edition 1991) by Combustion Engineering Inc., describe in detail from the equipment vendors' perspective the various kinds of boilers and their component parts.

Thousands of components and pieces of equipment that are designed and supplied by different firms must ultimately be properly assembled, tested, and, almost always, tuned and refined before a generating unit can be initially connected to the grid.

The design, installation, and operation of boiler and turbogenerator component parts must be fully integrated in order to achieve the ultimate objective of generating electricity reliably, safely, and at the least cost possible. This integration is, even for the simplest, smallest units, a major undertaking. Thousands of components and pieces of equipment that are designed and supplied by different firms must ultimately be properly assembled, tested, and, almost always, tuned and refined before a generating unit can be initially connected to the grid. Furthermore, it is not unusual for replacements of equipment and systems and refinements to operational procedures to continue for months and years before a unit achieves its efficiency and reliability objectives.

Maintaining integrated operation of all components is difficult because of the large number of components and the varying stresses on components. Failure of a component, or its failure to meet performance specifications, results in the inability of a unit to perform efficiently or to generate at design capability and may even prevent the unit from generating at all. This is true for almost all components. Failure of a critical electrical relay, sensing device, or valve can interfere with a unit's ability to operate properly as much as can failure of larger boiler or turbine components.

The components and equipment of a generating unit face a wide range of operating environments and service conditions. These conditions range from the heat- and humidity-controlled environment of a control room to the extremely harsh environment inside a large furnace. Heat transfer surfaces in a boiler must retain adequate structural integrity to contain water/steam at pressures up to 4500 psi, the approximate equivalent to an ocean depth of two miles.

Components must retain this structural integrity while being exposed to furnace temperatures exceeding 3000F; to highly corrosive gases; to deposition of corrosive solid materials; and to erosion caused by high-velocity, abrasive solid materials. Solid particles and water droplets traveling at supersonic velocities bombard steam turbine blades. Dynamic forces from the formation and collapse of steam bubbles can gouge chunks of metal from seating surfaces and rotating elements of control valves and pump impellers. Insulation inside electrical generators must maintain integrity while withstanding up to 24,000 volts.

Because of this wide variation in conditions of service, the service lives of individual components differ considerably. This affects the ability to maintain reliable integrated operation. Even the various components of a system or assembly do not have the same expected service life. For example, the rotating elements of a steam turbine, under design conditions, will require repair or replacement before the stationary components of the turbine. The superheater section of a boiler, which operates in a substantially more hostile service environment than the economizer section of the same boiler, typically has a shorter life than the economizer—even though the superheater is made of higher grade materials that can tolerate very adverse conditions.

The power system may fail to meet its performance and reliability expectations because of design and integration errors. Components often fail to achieve their initially anticipated service lives. Poor quality control, manufacturing errors, design errors, and imperfect information regarding conditions of service can result in exposure to stresses higher than anticipated by the design engineer. Unexpected trace materials in the fuel supply can result in higher corrosion. Improper operation due to human error or failure of control components may also shorten component lives. For example, a single overheating event can occur early in the life of a plant and shorten the useful life of an entire section of heat transfer surfaces within a boiler (e.g., a superheater or reheater). All of these circumstances eventually require some form of maintenance response to ensure safe and reliable operation.

Advances in industry standards, metallurgical developments, and improvements in inspection procedures and performance-testing techniques can also result in reduced life for components. Codes and standards exist to minimize the threat of a major safety-related failure. Industrial experience and increased knowledge of materials behavior can result in changes to these codes and standards that require removal of components from service earlier than anticipated by the designer. For example, in 1965 and again in 1991, the American Society of Mechanical Engineers reduced the allowable high-temperature stress levels for 11/4 Cr, 1/2 Mo steel (chrome-molybdenum, also known as T-11), which was commonly used in the waterwall, reheater, and superheater sections of a boiler. This significantly affected the assessment of remaining useful life for some of the boiler sections fabricated from this material. Similarly, the development of improved nondestructive examination techniques for boiler tubes and other components allowed sophisticated assessments of the remaining useful life of pressure parts to be conducted, which in turn allowed for planned replacements of wearing parts to be undertaken before a forced outage required emergency repairs.

Life of a Generating Unit

Given the variations in the design life of individual unit components and systems, the life of a generating unit depends upon how a unit is operated, how well it is maintained, and other external factors. As a result, there is no preordained expected life of a generating unit. For TVA and other generating utilities, there are in fact two different concepts of expected life.

Given the variations in the design life of individual unit components and systems, the life of a generating unit depends upon how a unit is operated, how well it is maintained, and other external factors.

First, there is the project planning life or accounting life. When a decision is made to put a new generating unit on line, a minimum expected lifetime is defined for accounting or planning purposes. In other words, for a project to be viable, it must be expected to perform long enough to generate sufficient revenues to provide a minimum targeted return on investment. In the case of for-profit entities, this minimum expected life or "accounting life" also establishes the depreciation schedule, an important parameter in the economic evaluation of a new project because of tax considerations. TVA periodically adjusts its depreciation schedules to reflect current estimates of a plant's remaining useful life. It is not unusual, however, for a generating plant to become fully depreciated yet remain in service.

Second, generating units have a useful life, one that is based on a dynamic assessment of unit-specific internal and external factors to determine its continuing viability. Just as automobiles are not retired once the car loan is paid, generating units are not retired from service at the end of their accounting lives simply because they have been fully depreciated. Rather, they are retired when they no longer remain viable assets. This means that units are removed from service when either:

- The revenue they generate is inadequate to cover fixed plus variable operating costs and to provide sufficient return on investment in needed component restorations; or
- Technological advances provide the opportunity for an investment in new facilities to generate greater return on investment and lower cost of electricity than could be achieved through continued operation of the existing facility.

Maintenance, repair, and replacement of unit components are necessary to achieve reliable and safe operation of a generating unit throughout this useful life.
Since 1940, TVA has permanently shut down 24 steam-driven electrical power plants. TVA acquired 23 of these plants from other power companies or from the government. One of the 24 plants shut down was the Watts Bar coal-fired plant, the first steam plant designed and constructed by TVA. Many of the plants included in the acquisition of entire utility systems had internal combustion engines and were retired immediately upon their acquisition. Others were coal-fired plants of varying size and description that were shut down from 1941 to 1997 based on system needs and the relative economics of the individual plants.

Review of this retirement history shows that retirements of coal-fired units on the TVA system have been limited to small (<60 MW) units that operated at low steam pressure and low temperature and had high heat rates (low efficiency) compared to other existing TVA units. Those units identified in Table 1 represent the largest and most efficient of the coal units shut down by TVA.

Table 1 Thermal Conditions of Retired TVA Fossil Units

	Steam Pressure (PSI)	Steam Temp (T)	Estimated Heat Rate (Btu/kWh)
Parksville	250	575	21,000
Hales Bar	365	725	18,000
Watts Bar	865	900	11,400*

* Design Value

As demand grew on the TVA electrical system, substantially larger, more efficient generating units were added. The significantly lower production cost of these new units resulted in the older units being used less. This decrease in utilization led to the old units' net annual revenue going negative (often, even net generation would go negative). Retirement of the old units typically followed soon thereafter.

Table 2 was compiled based on information obtained from a review of TVA's Annual Reports to the President and Congress in 1957-1959. Table 2 compares the average cost and capacity factor of the TVA-acquired units that were in service and the average figures for the TVA coal system overall. For example, in the late 1950s, the average cost of electric power generated by TVA's old, acquired units was about 4.4 to 6.5 times the cost of electric power generated by TVA's new coal-fired units. The acquired units were all retired in the early to mid-1960s. (TVA retired the Parksville, Bowling Green, and Watauga units in 1960, the Nashville plant in 1962, Hales Bar in 1963, Memphis in 1965, and Wilson in 1966.)

Table 2 Financial Performance of TVA Coal Units 1957-1959

	1957	1958	1959
Tva Coal System - Average Cost ($/MWh)	2.773	2.898	2.793
Effective Capacity Factor (%)	90.110	77.960	82.200
TVA-Aquired Units* - Average Cost ($/MWh)	17.918	12.640	17.200
Effective Capacity Factor (%)	4.440	4.740	3.130

* Generating units acquired by TVA from other power companies or from other government agencies from 1933 through 1950. Plants still active in 1957-1959 included Wilson, Nashville, Hales Bar, Parksville, Watauga, and Bowling Green.

This retirement sequence demonstrates that neither the accounting age nor the actual age of units dictates when units are retired. TVA's 1960 Annual Report indicated that the Nashville, Memphis, and Parksville units had reached the end of their accounting lives; that is, they were fully depreciated. Yet, the 1960 retirements included the Bowling Green and Watauga units but not the Nashville and Memphis units. Table 3 provides a summary of the age of some of these acquired facilities at the time of their retirements. Even in the 1950s and 1960s, unit age at date of retirement ranged from just less than 30 to over 60 years, confirming that plant age was not the motivation behind retirement.

Table 3 Age of TVA Coal-Fired Plants at Retirement

Generating Unit	Retirement Date	Age at Retirement
Hopkinsville	1954	41
Parksville	1960	46
Bowling Green	1960	28
Watauga	1960	38
Nashville	1962	61
Hales Bar	1964	40
Wilson	1966	50

TVA's most recent plant to be shut down was the Watts Bar Steam Plant. This four-unit, combination wet-bottom/dry-bottom boiler plant was the first coal-fired plant actually built by TVA. The units began operation in 1942-45. In only one decade, the units' operation was shifted from base-load to peaking mode following completion of the Kingston units in 1954-55. The technology of coal-fired generating stations had evolved considerably during this period because of increases in operating temperature and pressure and the addition of steam reheating[1] to the thermodynamic steam cycle. As a result, the new Kingston units were approximately 20 percent more efficient than the Watts Bar units (design heat rates of 9,400 Btu/kWh compared to 11,400 Btu/kWh at Watts Bar) and produced electricity at costs substantially lower than the Watts Bar units.

The generation from Watts Bar continued to decline as other generating units were added to the TVA system until, as early as 1960, the net generation of the plant was negative—it consumed more electricity when it wasn't operating than it generated when it was operating. The units were effectively retired at ages ranging from 15 to 18 years. However, Watts Bar's value as backup capacity exceeded the cost to maintain it as a viable generating asset, so it continued to be staffed and remained capable of operation. This changed in 1982 when an analysis indicated that, for the number of hours of expected operation, it would be more economical to generate the standby power from combustion turbines than to maintain full staffing and absorb the total fixed cost of the Watts Bar facility. As a result of this analysis, the plant was shut down and put into mothballed condition. Subsequently, in 1997 Watts Bar was permanently shut down—55 years after going into service.

Technological advances have continued to improve the efficiency and reduce the variable operating costs of new generating units. However, these more recent efficiency improvements have not approached the giant strides that were made in the 1950s and 1960s. Additionally, the economy-of-scale factor that allowed the fixed cost of the replacement capacity to be relatively small prior to 1970 is no longer relevant because there has been no increase in the size of generating units since the early 1970s. In fact, almost all of the new generating units added in the 1990s have capacities considerably smaller than those built in the late 1960s and early 1970s. Simply stated, the more recent limited improvements in unit operating efficiencies are not sufficient economically to justify the replacement of existing units, especially when the public's demand for electricity has continued to increase.

1 Refer to the case study on reheater replacement on p. 28 of this report for additional details.

Service Mandates

Maintaining generating units to ensure they are available to generate when needed is a critical element of any program to ensure reliability of supply.

The TVA Act requires TVA to provide an ample supply of electric power to aid in discharging its congressionally mandated responsibility for the advancement of national defense and the physical, social, and economic development of the TVA region. The TVA Act also requires TVA to provide power at the lowest feasible rates, which in turn requires that TVA generate power at the lowest feasible cost.

Maintaining generating units to ensure they are available to generate when needed is a critical element of any program to ensure reliability of supply. Maintenance activities are also necessary to reduce costs. If generating units are not reliable, more capacity must be installed (or obtained from some other power supplier) to ensure that total energy needs are met. Furthermore, if the lowest cost coal-fired units are not fully available when needed, energy needs must be met from generating units with higher production costs.

As a member of the North American Electric Reliability Council[2] (NERC), TVA is also obligated to help preserve the reliability of the national electricity transmission and distribution grid. NERC's Operating Policy 1, Section C, defines the responses required of participating utilities in order to maintain acceptable frequencies at the transmission interfaces between entities. Upsets such as loss of a major generating unit on another utility's system can require TVA to activate its standby generation facilities or start idle ones. In addition to having an obligation to respond reliably to such events, TVA must minimize the number of events that are initiated on its system. Reliable generation and the ability to control the times when generating units operate or are shut down are crucial to fulfilling this obligation.

In addition, TVA must operate its generating units and transmission assets in a manner that fully protects the health and well-being of its employees. As a result, TVA strives to promptly correct conditions that might lead to an unsafe or unhealthy working environment.

Other companies that own and operate electricity-generating facilities for profit have also long been under a legal duty to maintain and to operate their facilities in a manner that ensures a safe, efficient, and reliable supply of electricity to their consumers. This legal duty is described in the utilities' compacts with their public service or public utilities commissions (PUCs). Activities aimed at improving or maintaining the reliability and efficiency of generating facilities are also subject to public scrutiny through reports to state PUCs, to the Federal Energy Regulatory Commission (FERC), and to the Energy Information Administration (EIA) within the U.S. Department of Energy.

2 NERC is a not-for-profit organization responsible for promoting the reliability of the electric supply for North America. This mission is accomplished by working with all segments of the electric industry as well as customers. Electric utilities formed NERC in 1968 to coordinate efforts to avoid blackouts such as the November 1965 event that left 30 million people without power in the northeast U.S.A. and Ontario, Canada. NERC reviews the past for lessons learned and monitors the present for members' compliance with published policies, standards, principles, and guides. NERC assesses the future reliability of the bulk electric systems in North America. NERC's owners are ten regional councils whose members come from all segments of the electric industry—investor-owned, federal, state/municipal, and provincial utilities, electric cooperatives, independent power producers, power marketers, and electricity customers. TVA is a member of Southeastern Electric Reliability Council (SERC). NERC governance is by a board of trustees comprised of 47 electric industry executives. TVA has representation on the board of trustees. Operating guides and policies are developed and revised by committees comprised of members from the ten councils. Guides and policies are approved at various levels and ultimately by the board of trustees. (Information from NERC's Web site, January 2000 - http://www.nerc.com)

Theory of Maintenance

To fulfill their respective obligations to serve, TVA and the rest of the electric utility industry have developed a very simple maintenance philosophy—maintain the reliability of generating units in a way that preserves the value of the asset and minimizes the cost of electricity. For some maintenance activities, this simple statement is equally simple to implement. However, for other activities, determining the appropriate approach may involve more complicated engineering and economic evaluations. Furthermore, the conclusions that are reached today may not be valid at some future date because of changes in the technology or economic circumstances.

To fulfill their respective obligations to serve, TVA and the rest of the electric utility industry have developed a very simple maintenance philosophy—maintain the reliability of generating units in a way that preserves the value of the asset and minimizes the cost of electricity.

Under this maintenance philosophy, routine maintenance of components of a generating unit generally falls into three categories. It can be proactive, reactive, or predictive.

Proactive

Utilities routinely change lubricants, clean lubricants, replace gaskets, repack pump seals, etc., based on fixed calendar schedules or hours of service—regardless of the condition of the equipment. Typically, major overhauls of equipment have also been performed on a predetermined schedule based on manufacturers' recommendations or utility experience. Improvements in monitoring and diagnostic capabilities in recent years have enabled plant operators to reduce the level of this proactive maintenance in favor of the more cost-effective "condition based" or predictive maintenance.

Reactive

Reactive maintenance is routinely performed when components or systems fail or experience performance degradation. This may entail replacement of components with identical parts, replacement with components with improved design or materials, replacement followed by changes in operating procedures, or replacement of an entire assembly or system that includes the failed component. The actions taken following a failure are determined by an economic evaluation that includes consideration of the immediate needs of the generating system, impact of the failure on unit operation, the frequency of the failure, and the availability of alternative solutions designed to prevent similar failures in the future.

When a failure results in loss of generating capability of a unit, either partial or total, the economics normally dictate choosing a maintenance solution that minimizes lost generation. This sometimes results in an immediate response to restore unit capability followed by a later action to avoid future failures. For example, consider the case of a tube failure in the reheat section of a steam generator.

- If the damage is isolated to a single tube, that area of the tube is cut out and replaced, and the unit is returned to service.
- If there is visible collateral damage or if it is clear from initial analysis and review of operating history that other tubes in close proximity to the failure have been exposed to similar conditions that would make their early failure likely, a larger number of tubes may be replaced before the unit is returned to service. In this case, reactive maintenance is augmented by a proactive component replacement in order to avoid future failures that would result in loss of generation or create safety risks.

- If it is determined that the root cause of a failure is a condition that has exposed all or a large number of the reheater tubes to increased risk of failure, the economic analysis may indicate that replacement of the entire reheater is needed to maintain unit reliability and safety and that replacement is the most cost-effective approach to maintaining system reliability. Such a condition might result from identification of a design or materials deficiency, operational errors such as temperature or water-quality excursions, or changes in the condition of service such as might result from unexpected changes in fuel combustion characteristics due to variation of properties within a coal seam. The economic analysis would indicate that the loss of generation and wear and tear on the unit resulting from anticipated failures and shutdowns justify the investment needed to replace the reheater.

Reactive maintenance can also be initiated by discovery of conditions that will lead to component failure if not corrected. If evidence of damage is found during inspections, a similar economic analysis is performed to determine the appropriate response. When the condition is detected prior to failure, however, repair of the component may also be a viable option. For example, discovery of cavitation damage at the suction of a pump could lead to weld repair of the pump impeller, replacement of the impeller, replacement of the impeller with improved materials, reconfiguration of the suction piping, or changes to the system upstream of the pump. The selected course of action would depend upon the costs of the alternative solutions and the benefits each solution would provide to system reliability.

Predictive

As technology has advanced, so have the maintenance tools used by the electric utility industry. Advances in equipment-monitoring capability and analytical techniques now achieve many of the benefits of proactive maintenance while avoiding the costs of inspecting and overhauling equipment that is operating well and poses no current threat to unit reliability or employee safety. Predictive capability also allows threatening conditions to be discovered and mitigated prior to failure, thus avoiding the cost of lost generation, wear and tear on equipment that occur during the shutdowns and startups that accompany failures, and safety risks associated with a failure.

Examples of predictive or condition-based maintenance are plentiful. Deterioration of a piece of rotating equipment can now be discovered by spectral analysis long before vibration reaches levels that would have been detectable with originally installed equipment. Portable vibration-monitoring equipment allows this analysis technique to be extended to components that have never previously been equipped with any type of vibration-monitoring equipment. Evaluation of metallurgical samples now enables the condition of tubing or other structural members to be determined and the remaining service life of the component to be predicted with increased precision. This allows the replacement of components before failure while fully utilizing the life of the component. Modern computational fluid dynamics capabilities allow the prediction of corrosive conditions within boilers that may result from installation of low-NOx burners. This enables localized mitigation techniques such as protective cladding to be applied.

Timing of Maintenance Activities

The economic evaluation of maintenance activities at a generating unit is dependent upon a total generating system optimization that assigns a role and set of operating objectives to each individual unit. Unit roles and objectives change because of independent factors that include changes in fuel costs, overall economic conditions, and the condition of other units in the operating system. As a unit's role changes, the maintenance practice for that unit may also change.

For example, a unit operating as a "swing" or load-following unit affords more opportunities to patch or replace failed components one at a time without severely impacting systemwide reliability because system load demand does not require that the unit be operated continuously. (It should be noted that this swing mode of operation might, in fact, create more opportunities for failure because of the thermal, mechanical, and electrical cycling of equipment and systems.) However, conditions on the operating system (such as loss of another generating unit for an extended period of time) can quickly change the role of the unit to base-load operation. Because a base-load unit is expected to operate continuously, opportunities for failure-driven maintenance are less frequent and certainly more costly. Proactive replacement of a complete assembly of components that have failure potential, rather than reactive replacement of individual components, may become economically justified with the increase in production rate or hours of operation.

Many of TVA's coal-fired units experienced a major change of roles in the mid-1980s when TVA decided to shut down all operating nuclear units for an extended period because of safety concerns. The reliability of the coal-fired units during this period became critical to meeting system demand and fulfilling TVA's mission and obligation to serve.

Decisions to repair or replace and the scope of the repair or replacement are not based only on assessments of the least-cost approach to maintaining the requisite reliability of TVA's generating and transmission system. The evaluations of options at a generating unit must also include consideration of the condition of the rest of the electrical system and the general economy as well as the safety of TVA employees.

Technologically Superior Replacement

It has been the common practice within TVA and the utility industry for decades to replace components and systems with state-of-the-art equipment that is often more reliable or more efficient than the original, sometimes obsolete, component. It is also typical for maintenance activities to include improved maintenance and operational practices that respond to conditions experienced during actual operation of the unit. The following discussion lists specific examples of these practices on the TVA system.

Replacements with improved design or materials

- Boiler feedpump recirculation valves for supercritical units underwent a complete evolution of materials and design and were replaced numerous times on many units.
- Cooling tower fill was replaced with fill systems that had better structural and thermal properties and/or eliminated asbestos materials.
- Metallic expansion joints were replaced with more durable fabric joints.

- Insulation of generator stator bars was upgraded because of continuing failures of the originally supplied design.
- Steam turbine blade shape and materials of construction have been improved with resultant increases in thermodynamic efficiency and reliability.
- Feedwater heaters have been completely retubed with new materials that have improved the reliability of the heaters with resultant increases in thermal efficiency of the generating units.
- Analog control systems have been replaced with digital systems that provide increased control flexibility and accuracy and improved reliability.

Improved maintenance tools or operational practices

- Continuous-cleaning systems for condenser tubes have increased efficiency through improved heat transfer capability and increased reliability by eliminating the need for unit outages or short-term load reductions to manually clean tubes.
- Vibration-monitoring systems with expanded capability have provided increased analytical capability and have increased the number of pieces of rotating equipment that can be monitored. This has resulted in improved reliability by making maintenance programs more effective and avoiding forced outages.
- Continuous-emissions-monitoring equipment has been added to improve combustion controls and overall thermal efficiency.
- Continuous-cleaning and filtration systems have been added to lubricating oil systems of turbine generators and other large rotating equipment to improve bearing life and decrease bearing-related forced outages.
- More recently, artificial intelligence control systems have been added to continuously optimize unit efficiency while minimizing pollutant emissions.

TVA Historical Practices

In an effort to maintain unit reliability, major replacement or rehabilitation in areas where excessive tube failures occur is made after an evaluation based on loss of generation, cost of repairs, and damage to the unit from frequent startups and shutdowns indicates it is justified.

The overall maintenance philosophy described above has been in place at TVA for many years. This philosophy is reflected in a report presented to the American Power Conference in 1972, "TVA's Power Plant Maintenance Program" by T. H. Gladney and H. S. Fox. At the time of that report, TVA's oldest coal-fired plant had been in service just over 20 years. Many of the units were less than 10 years old. The report clearly stated TVA's approach to maintenance:

> *In an effort to maintain unit reliability, major replacement or rehabilitation in areas where excessive tube failures occur is made after an evaluation based on loss of generation, cost of repairs, and damage to the unit from frequent startups and shutdowns indicates it is justified.*

Examples of the types of routine maintenance activities and projects that were identified in the report after less than 20 years of operation include the following.

- In one family of 14 similar turbines, 3 high-pressure spindles had to be replaced because of creep-rupture cracking.
- Another high-pressure spindle was replaced and two intermediate-pressure

spindles were on order following discovery of unacceptable cracks in the rotor bore.

- Steam chests were replaced on two 700 MW units after only 8 years of operation.
- Four generators required complete stator rewinding with upgraded insulation material, and 42 percent of the total generator fleet required partial replacement of bars.
- Although the projects had not yet been implemented, the decision had been made to pressurize the penthouse on all pressurized furnaces.
- Most crotch tubes, reentrant throat tubes, wrapper tubes, and face tubes had been replaced at least once on all cyclones of two 700 MW units, and it was thought that replacement of all cyclone tubes would be required within 3 to 5 years. (See Paradise Unit 1 Cyclone Replacement Case Study later in this report.)
- Of 41 low-pressure heaters using admiralty tubing, 14 had been retubed using better quality copper-nickel material and all others were anticipated to require retubing in the near future.
- Stainless steel tubes were removed, heat-treated, and reinstalled in the superheater and reheater sections of 11 steam generators.
- The return bends in all reheater pendant elements of two steam generators were redesigned and replaced.

These maintenance activities left the basic design of the steam/heat cycle and the maximum heat input to the furnace unchanged. Within these overall design constraints, however, all of these maintenance activities were intended to improve the reliability or efficiency of the generating units.

Case Studies

The same TVA maintenance philosophy has been consistently applied since the Gladney-Fox report. Four case histories of maintenance projects are presented below. Each case presents a discussion of the component, its function, and its conditions of service; the relevant operational history of the component; alternatives considered; and the rationale behind the maintenance decision. This specific case is then extended to analyze the history of replacements of the component on both the entire TVA coal-fired system and a larger data set that represents either the entire electric utility industry or a large segment of the industry.

Cyclone Furnace Replacement

Cyclone Background

As related in Steam: Its Generation and Use[3], cyclone-fired boilers were developed by Babcock and Wilcox (B&W) to burn coals with low ash-melting (fusion) temperatures that are not well suited for pulverized-coal (PC) combustion. The ash from these coals would enter the superheater of a PC unit in a molten state and create severe slagging

3 Babcock and Wilcox, Steam: Its Generation and Use, 40th edition, 1992, pp. 14-1 - 14-11

and fouling problems. The "cyclone" design developed by B&W addressed this problem by deliberately melting as much ash as possible and draining it from the bottom of the furnace. This kept molten slag out of the superheater and substantially reduced the total amount of ash that was transported out of the boiler with the flue gas (fly ash). The cyclone design also had these collateral benefits:

- Eliminated the need for high-cost and high-maintenance pulverizers.
- Resulted in overall smaller furnaces (with the associated reductions in powerhouse dimensions).
- Required smaller particulate collection equipment due to reduced fly ash loading.
- Opened the market to a range of fuels that were not usable with pulverized-coal firing.

The design objective was accomplished by creating a zone where combustion takes place outside the main furnace. The hot flue gas and molten slag then discharges into the main furnace, with the gas being cooled and discharged from the top of the furnace while the molten slag is kept at elevated temperatures and is drained through the main furnace bottom. This allows very high temperatures to be maintained in the combustion zone while the majority of the evaporative heat transfer occurs in the main furnace.

These combustion zones or "cyclones" are horizontally oriented, cylindrical barrels that attach to the sides of the main furnace. Cyclones range from 6 feet to 10 feet in diameter. As few as 1 or as many as 23 of these cyclones are attached to the main furnace of different units. The term "cyclone furnace" is used to describe both the individual cyclones and the total furnace assembly of a cyclone-fired unit. The cyclones are a water-cooled, tangent tube construction, but a thick layer of refractory lining is used to protect the tubing material while allowing the sustained high temperatures (greater than 3000F) needed to consistently melt the ash. B&W describes the operation of cyclones as follows:

> *Crushed coal and some air . . . enter the front of the Cyclone through specially designed burners in the frontwall of the Cyclone. In the main Cyclone barrel a swirling motion is created by the tangential addition of the secondary air in the upper Cyclone barrel wall. A unique combustion pattern and circulating gas-flow structure result. . . . The products of combustion eventually leave the Cyclone furnace through the re-entrant throat. A molten slag layer develops and coats the inside surface of the Cyclone barrel. The slag drains to the bottom of the Cyclone and is discharged through the slag tap.*[4]

While cyclones achieved their design objectives, they also presented some difficult problems. The introduction of crushed coal and air at high velocities resulted in erosion problems, particularly in areas of the cyclone that do not form a protective slag layer. The hot, molten slag environment also introduced high risk for corrosion damage to the water-cooled tubes. Generally, the refractory material would protect the tubing. However, in areas where refractory eroded, cracked, or otherwise was removed from the tubing, the tubing's exterior surfaces would be subjected to the

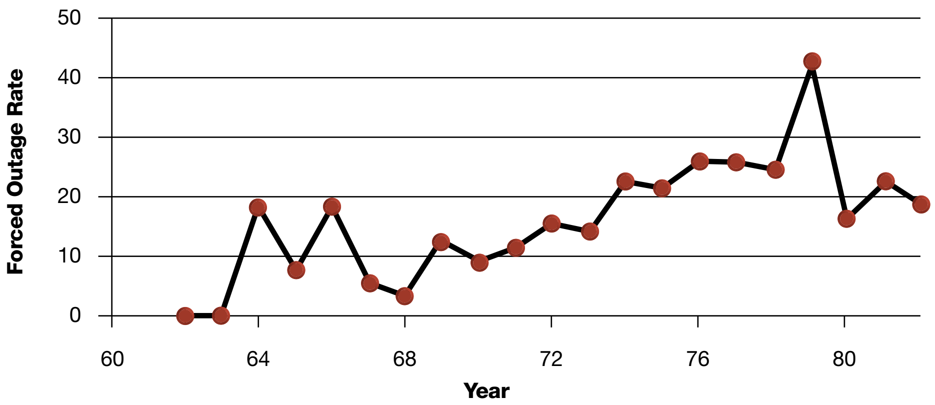
4 Babcock and Wilcox, Steam: Its Generation and Use, 40th edition, 1992, p. 14-1

corrosive matter (such as iron sulfide) and rapidly lose metal thickness and strength. As a result, cyclones were plagued by tube failures that resulted in forced outages and decreased reliability. In the face of these cyclone failures, B&W developed rehabilitative repair and replacement strategies, such as welding flat steel stock onto tube surfaces in areas of high erosion potential and using a high-density pin-studding pattern to better hold refractory in place.

Paradise Unit 1 Case Study

Unit 1 of the Paradise Fossil Plant (located on the Green River in Muhlenberg County, Kentucky) is a 700 MW (nominal) cyclone-fired unit that was put into service in 1963. It has 14 ten-foot diameter cyclones—7 on each of the front and rear walls. Its boiler produces steam at 2450 psig, 1003F. Within its first year of commercial operation, the unit began experiencing failures of cyclone tubes. These failures increased in frequency such that by the time of the Gladney and Fox report in 1972, most of the crotch tubes, reentrant throat tubes, wrapper tubes, and face tubes had been replaced at least once. It was projected at that time that replacement of all cyclone tubes would be mandatory within 3 to 5 years, but this anticipated wholesale replacement was delayed by a manpower-intensive program of frequent, proactive, tube replacements. This piecemeal replacement of the tubes continued through 1982; however, during this period the cyclones continued to exhibit failures that resulted in decreasing reliability, wear and tear on equipment, and labor and materials charges. The increase in unit forced outages from 1962 is shown in Figure 1. (The peak forced-outage rate experienced in 1979 was the result of a single turbine casing failure that resulted in a forced outage of approximately 1350 hours and contributed 20.5 percent to the 42.5 percent forced-outage rate for the year. Without this single event, the forced-outage rate for 1979 would have been about 22 percent—consistent with the trend at the time but still unacceptably high.)

Figure 1 Paradise 1 Forced Outage Rate



The contributions to forced outages for calendar year 1982 are analyzed in Table 4 below. These data show that cyclone failures were the principal cause of the unit's degraded performance.

Table 4 Paradise 1 - 1982 Forced Outage Rate (FOR) Analysis

Description	No. of Events	Forced Outage Hours	MWH Loss	Contr. To Unit FOR	Estimated Differential Power Replacement Cost
Cyclone Tube Leaks	10	882	516118	15.50	4,077,000
Waterwalls	2	158	98052	2.95	775,000
Condenser Shell	1	17	10839	0.33	86,000
Wet Coal	2	11	6881	0.21	54,000
Main Turbine Control Valve	2	5	2903	0.09	23,000
Main Turbine Shop Valve	1	2	1002	0.03	8,000
Boiler Feedpump Turbine	1	1	744	0.02	6,000
Total	19	1026	636539	19.12	5,029,000

In addition to decreasing reliability and increasing costs, cyclone repairs were becoming increasingly manpower-intensive. Although there were only ten forced-outage events attributed to cyclones during calendar year 1982, there were 213 tube leaks (and 168 leaks in 1981). Each of these leaks required maintenance attention.

As discussed above, when equipment experiences repeated failures that adversely impact performance, it is TVA's practice to undertake a structured analysis of various alternatives to correct the problem. The maintenance decision involves a choice between:

- Repair or replacement of individual components (reactive maintenance);
- Replacement of other components that have also experienced conditions that could affect future performance (proactive maintenance); and
- Incorporation of improved materials or design elements that might help address the causes of equipment degradation in the future.

TVA evaluated three primary options to address this unacceptable situation.

1. Do nothing - Make no proactive tube replacements. Take only those measures necessary to return the unit to service after cyclone tube failures.
2. Status quo - Continue with the past program of proactive replacement of damaged or high-risk tubes.
3. Replacement - Replace all cyclones in a single scheduled outage, incorporating advances in materials and design developed by B&W based on lessons learned in service.

TVA knew that there were similar cyclone problems at other utilities and that other utilities had replaced cyclones as part of their maintenance programs. The TVA analysis considered the results that had been achieved or projected by other utilities with similar large boilers. The results achieved by these utilities are shown in Table 5 below.

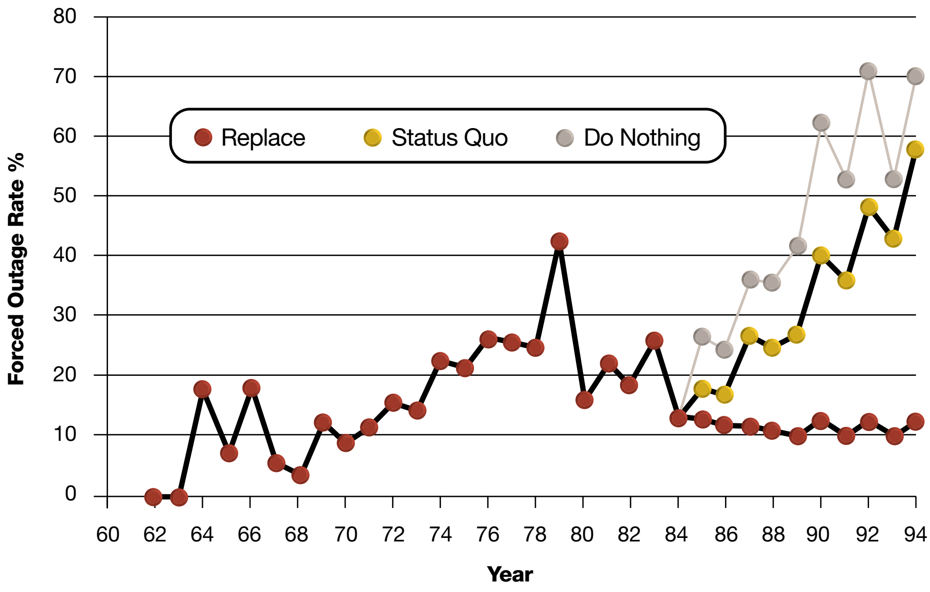
Table 5 Results of Prior Cyclone Replacements

	Unit 1	Unit 2	Unit 3
Availability Before	60%	59%	50%
Availability After	82%	78%	75%*
FOR ** Before	24.5%	29%	35%
FOR After	6.58%	13%	12%*

* Projected results - projects were being implemented at time of economic evaluation.
** FOR - Forced Outage Rate

Based on TVA's experience to that time, complete inspection and evaluation of the condition of the cyclones, and the results of similar replacement projects performed by others, TVA projected the future performance of the unit for all three options as shown in Figure 2.

Figure 2 Performance Projections for Paradise 1 Cyclone Options



Using these projections for future performance, the expected cost of the three options, and projected differential costs for replacement power, the economic analyses produced the results shown in Table 6.

Table 6 Paradise 1 Cyclone Options Economic Evaluation

	Low-Load Forecast*	High-Load Forecast*
Present Worth Savings ($ million)		
Alternative 2 vs. Alternative 1	-2.70	5.90
Alternative 3 vs. Alternative 1	15.90	45.30
Benefit/Cost Ratio		
Alternative 2 vs. Alternative 1	0.75	1.58
Alternative 3 vs. Alternative 1	2.11	5.12

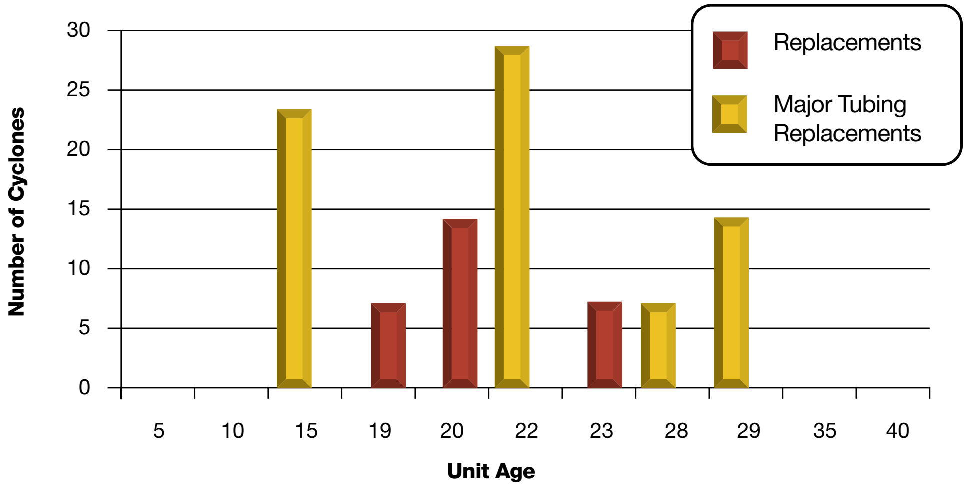
* TVA typically projects a range for future energy demands on its system: low-, medium-, and high-load forecasts. This table shows the range of cost estimates based on the low- and high-load forecasts at that time.

As Table 6 shows, Alternative 3 (full replacement during a scheduled outage) was the best alternative, maximizing both the savings and the benefit/cost ratio for both the low- and high-load forecasts. TVA chose Alternative 3 and implemented the project in 1984.

Experience on the TVA System

TVA operates six cyclone-fired units, three each at the Allen and Paradise Fossil Plants. In total, the Allen units have 21 seven-foot diameter cyclones and the Paradise units have 51 ten-foot diameter cyclones. All the cyclones have experienced the erosion and corrosion problems discussed above and, like Paradise Unit 1, all the originally supplied cyclones have been replaced. Figure 3 depicts the replacement history for these cyclones since 1978. The major tubing replacements refer to replacement of reentrant throat tubes at the Allen Fossil Plant. (Note that the replacements during the proactive, partial tube replacement effort are not included in Figure 3. That effort, which was performed at all TVA cyclones, is discussed above in the case study for Paradise Unit 1.)

Figure 3 TVA Cyclone History



Other Industry Experience [5]

The TVA experience with operating and maintaining cyclones is not unique. Virtually all cyclone owners have encountered the same problems with varying degrees of severity. There are 96 electricity-generating stations in the United States, (totaling 26,152 MW of capacity) powered by cyclone-fired furnaces. These units contain 701 individual cyclones. At these units, 300 cyclones (representing 13,981 MW of capacity) have been replaced since 1979. Industrywide data on partial replacements were not available for this report. Figures 4 and 5 show the number of cyclones replaced and the associated capacity as a function of cyclone age. The median age of the replaced cyclones was 21 years, while the mean age of those cyclones was 23.1 years.

Of these 300 replacement cyclones, only 13 cyclones (representing a total capacity of

5 Throughout this report, TVA experience is also included in the analysis of industry experience.

569 MW) were replaced with identical cyclones. All other replacements included some improvement based on the B&W rehabilitative repair and replacement strategies (discussed in the background above) or similar measures.

Figure 4 Utility Cyclone Replacement

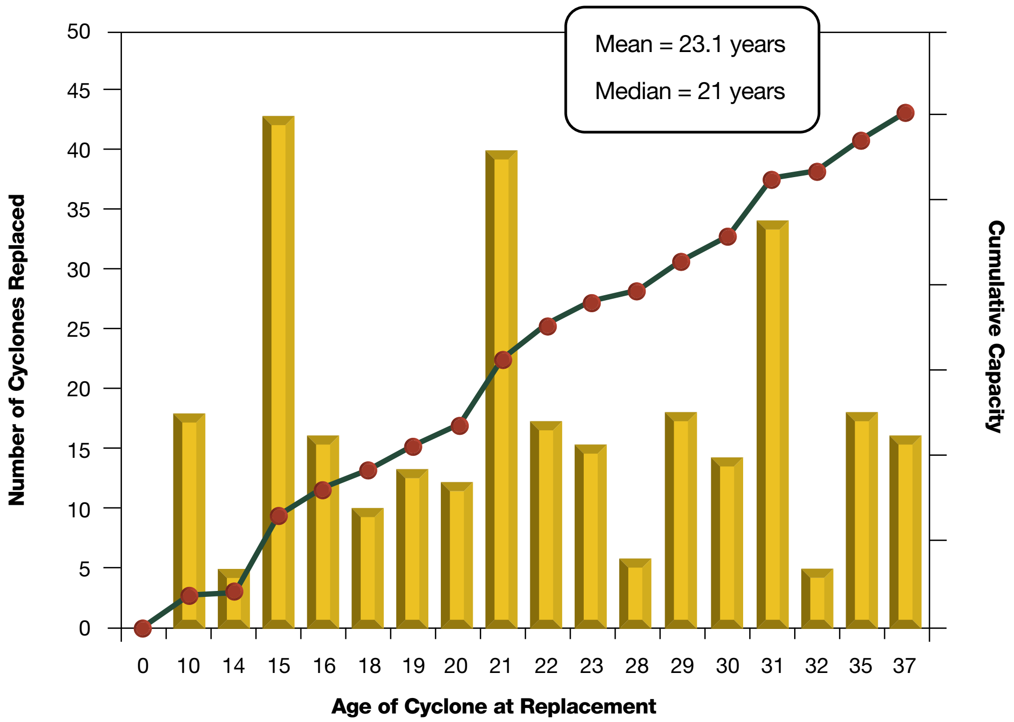
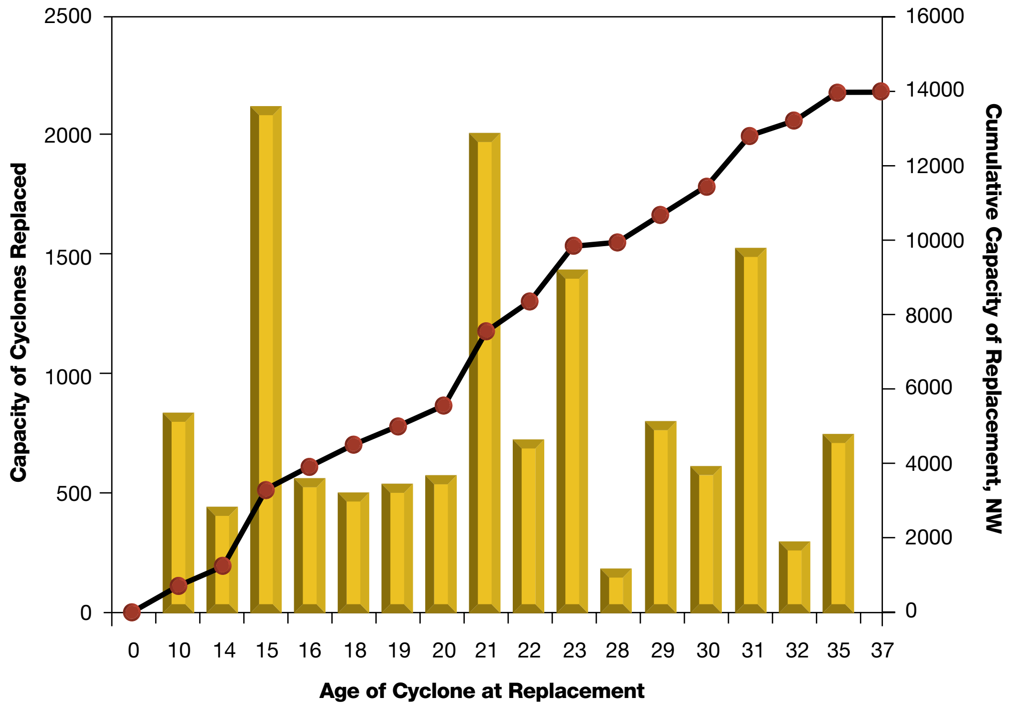


Figure 5 Utility Cyclone Capacity Replaced



It is apparent from the TVA case study and the analysis of industrywide maintenance history and practices that full replacement of cyclones has occurred frequently throughout the industry. It is also apparent that cyclones have been replaced on units of varying ages, confirming that many variables affect the actual condition and performance of boiler components. Full replacement of cyclones to correct problems created by corrosion and erosion of materials has occurred frequently and routinely throughout the utility industry.

It is apparent from the TVA case study and the analysis of industrywide maintenance history and practices that full replacement of cyclones has occurred frequently throughout the industry. It is also apparent that cyclones have been replaced on units of varying ages, confirming that many variables affect the actual condition and performance of boiler components.

Balanced-Draft Conversion

Balanced-Draft Background

In the 1950s, boiler designers began to employ a new design concept for large utility boilers—pressurized furnace operation. Prior to this design, the furnaces of all utility pulverized-coal-fired boilers had operated under a slight vacuum (negative pressure). The majority of these negative-pressure furnaces operated in a “balanced draft” mode. That is, they were equipped with a forced-draft fan that supplied the combustion air to the furnace and an induced-draft fan that mechanically drew the combustion gasses out of the furnace and expelled them through the chimney. Some smaller units were equipped with only an induced-draft fan, while some had no fans at all, using the draft effect of the chimney to draw air into the boiler and evacuate the combustion products.

There were several recognized incentives to move to pressurized firing. Operation with a negative-pressure furnace introduces some inefficiency caused by the unavoidable in-leakage of air not needed for combustion. This extra air requires additional motive power from the induced-draft fans and increases thermal losses because the total mass of hot gas lost from the system through the chimneys is increased. Keeping the furnace, the convective sections of the boiler, and the duct to the chimney under positive pressure eliminates this inefficiency. In addition, elimination of the induced-draft fan lowers the initial cost of the draft system and subsequent operation and maintenance costs.

The early installations with this forced-draft system design were initially successful and were soon followed by construction of other small, pressurized firing units. Pressurized firing was increasingly used in the industry by the mid to late 1950s and was widely accepted by the mid-1960s. (Of 284 boilers sold from 1955 to 1965 by Babcock and Wilcox and Combustion Engineering, the two largest boiler suppliers in the United States, 127 were pressurized. Of 185 sold from 1966 to 1975, 76 were pressurized.)

Although the pressurized furnaces were gaining in popularity during this period, certain shortcomings in the concept began to be manifested. Leakage of air into the furnace was replaced by leakage of combustion products out of the furnace. These combustion products, laden with fly ash and high concentrations of SO_2 and other corrosive gasses, caused several unacceptable conditions that called for a maintenance response:

- Infiltration of corrosive gasses and fly ash into the penthouses above the furnaces resulted in accelerated corrosion and structural failures.

- The employee work environment deteriorated because of exposure to high concentrations of combustion byproducts.
- Corrosion of components in the powerhouse near the boilers increased.
- Rotating machinery was exposed to increased levels of damaging particulate matter.
- Component performance was degraded because accessibility to the components was reduced, impeding performance of maintenance.

As a result, no pressurized Babcock and Wilcox units and only two pressurized Combustion Engineering units were sold after 1975 (none after 1977), and many utilities began to replace their forced-draft systems with balanced-draft systems to address equipment degradation and related health and safety problems. Some of the replacements were undertaken for economic reasons based on loss of reliability caused by component failure and inability to perform required maintenance. However, the primary reason for many of the replacements, including those on the TVA system, was improvement of the operating environment for plant personnel—employee health and safety.

The trend back to balanced-draft systems was accelerated by the addition of control equipment to meet air-quality regulatory requirements. The new control equipment added resistance (pressure drop) to the flow of the flue gas. Often, this added resistance could not be overcome by the existing draft system. Thus, when a utility considered the addition of control equipment, one of the options considered to enhance the draft system to accommodate the added pressure drop was replacement with a balanced-draft system. This was often the preferred option because it both accommodated the added pressure drop and resolved other operational, maintenance, and safety concerns, as discussed above. A TVA survey of 79 balanced-draft conversions indicates that 68 were done either out of concerns for employee health and safety or in conjunction with the addition of pollution-control equipment.

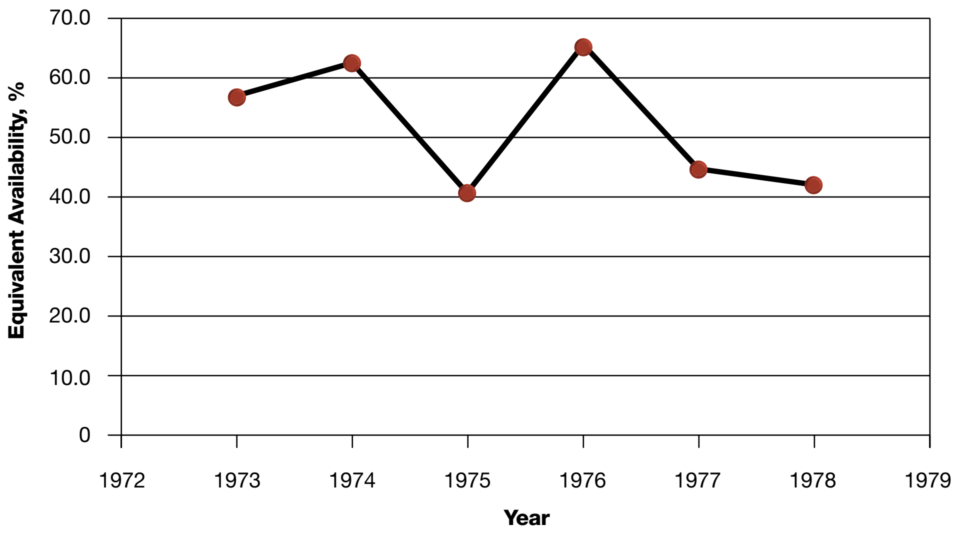
Cumberland Unit 1 Case Study

Unit 1 of the Cumberland Fossil Plant (located on the Cumberland River in Stewart County, Tennessee) is a 1300 MW (nominal) opposed-wall, pulverized-coal-fired unit that was put into service in 1973. It produces steam at 3650 psig, 1003ºF. The unit was not yet in service at the time Gladney and Fox reported in 1972 that the decision had been made to pressurize the penthouse on all pressurized units. This decision was made in an effort to mitigate the severe maintenance and safety problems that had been encountered on the six other TVA units that had been operating with pressurized furnaces.

Very early in the life of the Cumberland unit, it was apparent that state-of-the-art efforts to reduce gas leakage were inadequate. (These efforts included the redesign of tubing penetrations, sootblower penetration seals, expansion joints, and other design details aimed at reducing the tearing of ductwork and other pressure boundaries during boiler startups and shutdowns.) The environment inside the powerhouse when the unit was operating was intolerable—especially at upper elevations near the boiler bay. It was determined that the SO_2 concentrations inside the powerhouse exceeded the levels allowed for safe industrial occupancy.

Cumberland also was unable to consistently attain the reliability that is normally expected of a new generating unit. While this was due to a number of reasons, TVA determined that the hostile environment caused by the leakage from the pressurized furnace was a major contributor to the unit's poor initial performance, which is depicted in Figure 6.

Figure 6 Cumberland 1 Equivalent Availability



Accordingly, TVA decided to replace the pressurized firing system with a balanced-draft system in conjunction with its decision to add new, high-efficiency electrostatic precipitators to the unit for particulate control. In this instance, a rigorous economic evaluation justifying the decision was not made; providing a safer work environment for employees was deemed a major priority. The authorization document for the conversion states:

> . . . (G)as leakage from the boilers has resulted in sulfur dioxide and fly ash problems in the plant. Sulfur dioxide concentrations exceed the recognized national standard established to limit employee exposure and also prohibit adequate equipment maintenance and increase unit deratings. Also, the entrained fly ash infiltrates plant equipment, resulting in premature failures and further deratings. The addition of induced-draft fans and conversion to balanced-draft firing will eliminate these problems.
>
> . . . The addition of induced-draft fans and conversion to balanced-draft firing will bring the two Cumberland units into compliance with TVA Code VIII HAZARD CONTROL and consistent with the Occupational Safety and Health Act of 1970. The cost of converting these units to balanced-draft is estimated to be $41 million; this cost will be partially offset by the potential saving of reduced deratings and unit trips and by reduced plant maintenance.[6]

6 Tennessee Valley Authority Project Authorization, Serial No. 3384, September 29, 1978

The project was approved in 1978 and implemented in 1981.

Experience on the TVA System

Eleven of TVA's 59 operating units, totaling over 7,100 MW, were initially constructed and operated with pressurized furnaces. This included all units that went into service between 1962 and 1973. Today only one of these units, the 900 MW Bull Run unit, remains in pressurized operation.

Bull Run is unique among the TVA pressurized units in that it has historically burned coal with a much lower sulfur concentration. (The lower sulfur content reduces the corrosiveness and SO_2 concentration of gasses that may leak into the powerhouse.) Bull Run has experienced many of the adverse conditions associated with pressurized firing. However, the twin-furnace, membrane-wall construction of the unit combined with its continuous operation as a base-load unit burning low-sulfur coal has allowed plant staff to maintain a safe working environment while balancing the impact of reduced reliability and other economic penalties associated with pressurized units. The penthouse at Bull Run was pressurized in 1972.

Similar to the Cumberland project, other forced-draft system replacement projects on the TVA system were performed in conjunction with addition of environmental control equipment. Table 7 summarizes the history of TVA balanced-draft conversions.

Table 7 Draft System Replacements of TVA Coal-Fired Units

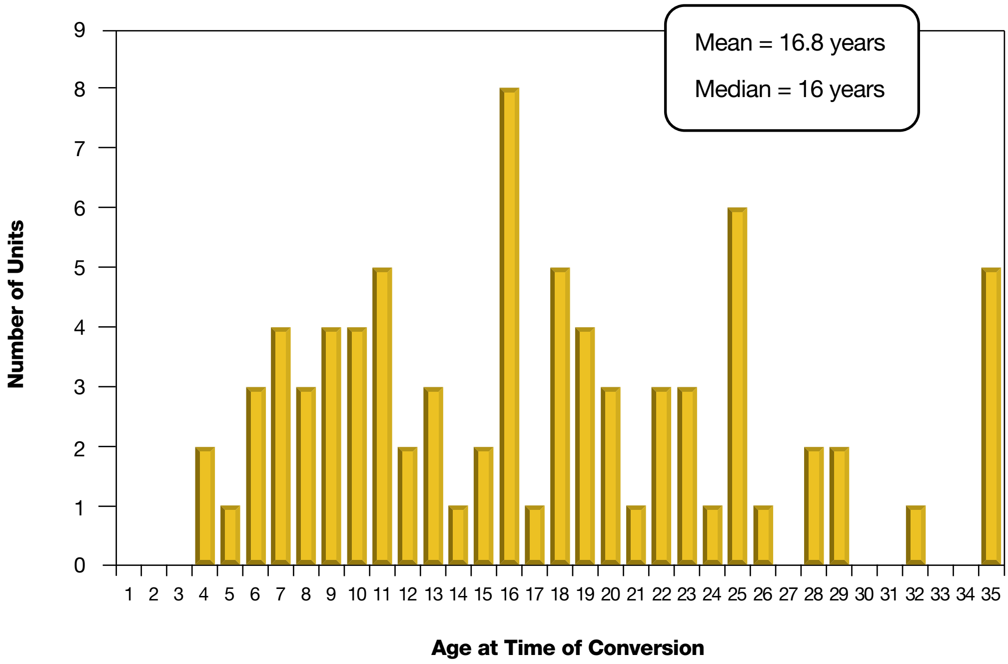
Unit	Size, MW	Date of Initial Operation	Date of Draft System Replacement	Concurrent Environmental Control
Allen 1	330	1959	1991	None
Allen 2	330	1959	1993	None
Allen 3	330	1959	1993	None
Colbert 5	500	1965	1981	None
Cumberland 1	1300	1973	1981	ESP
Cumberland 2	1300	1973	1982	ESP
Paradise 1	700	1963	1983	FGD
Paradise 2	700	1963	1983	FGD
Paradise 3	1150	1970	1983	ESP*
Widow's Creek 8	500	1965	1977	FGD

*Paradise 3 replacement of forced-draft system was delayed one outage cycle by delays in delivery of induced-draft fans.

Other Industry Experience

There are no readily accessible data that identify industrywide pressurized furnaces and those where a forced-draft system was replaced with a balanced-draft system. However, TVA was able to obtain data from a large sample of U.S. utilities that own a significant number of coal-fired generators. This data set includes 19 utilities that operate 166,000 MW of fossil generation. These utilities collectively own 151 boilers that were purchased and initially operated with pressurized furnaces. Within a 15-year period beginning in 1972, utilities replaced forced-draft systems with balanced-draft systems on 73 of these units. (Six other units were converted between 1991 and 1995 for a total of 79 conversions representing 52 percent of the sample population.) Draft system replacement did not alter these units' heat input capacity or steam flow but in most instances reduced the net electrical output because of increased auxiliary electrical loads for the induced-draft fans. The ages of the units at the time of the conversions are shown in Figure 7.

Figure 7 Balanced Draft Conversion Experience



The data show that these draft system replacements occurred regardless of the age of the unit, with age at conversion ranging from 4 to 36 years. On the TVA system, conversions to balanced-draft were justified primarily because of the need to improve working environments for employees.

These data show that replacement of forced-draft systems with balanced-draft systems in order to address equipment degradation, maintenance problems, health and safety concerns, and pollution control requirements has occurred frequently in the utility industry. The data show that these draft system replacements occurred regardless of the age of the unit, with age at conversion ranging from 4 to 36 years. On the TVA system, conversions to balanced-draft were justified primarily because of the need to improve working environments for employees. Improvement in unit reliability was an important collateral benefit. Balanced-draft conversions have occurred frequently and routinely in the utility industry.

Reheater Replacement

Reheater Background

Modern coal-fired power plants operate on cycles based on the regenerative Rankine cycle. In this cycle the boiler feedwater is converted to superheated steam in the boiler and used to drive a turbine-generator for electrical energy production. The steam is then condensed to liquid water to allow it to be pumped back to the boiler. The water is then heated using heat exchangers and returned to the boiler again as the boiler feedwater (thus being a regenerative cycle). In efforts to increase the plant thermal efficiencies (that is, reduce the amount of coal required to be burned for a specified output of electric power), the cycle was first improved to use superheated steam and then further improved with the addition of the reheat circuit. This latter addition, referred to as the reheat cycle, includes removing energy from the superheated steam in a high-pressure turbine and then returning the steam to the reheat section of the steam generator for additional heat energy. The steam is then again returned to the turbine-generator for further energy removal. For large installations, reheat makes possible a thermal efficiency improvement of approximately 5 percent and substantially reduces the heat rejected to the condenser cooling water.[7]

Most of the TVA coal-fired plants built since 1951 (all since 1954) use the reheat cycle. The portion of the steam generator that transfers the heat to the steam is referred to as the "reheater" or the "reheat superheater." This system is, in general terms, a simple single-phase heat exchanger with steam flowing on the inside and the flue gas passing on the outside, generally in a cross-flow configuration.[8] The major components are:

- Inlet header (which distributes steam returning to the boiler from the high-pressure turbine exhaust to the individual tubes)
- Heat exchange tubes or elements (horizontal, pendant, platen, terminal, or crossover depending on individual design)
- Outlet header (which collects heated steam from the individual tubes for passage to the intermediate-pressure turbine)

Because of the high operating temperatures, appropriate construction materials are critical to a successful reheater design. Accordingly, steel alloys were used in parts of the reheater construction because of their superior high-temperature properties and resistance to oxidation. But, as in all components of these steam generators, portions not operating at high temperatures were constructed of lower alloy steels (also referred to as higher carbon steels) that were lower in cost. The design of the reheater components, as other boiler components, was an attempt to optimize between the initial cost of materials of construction and the need for higher-cost steel alloys for reliable operation.

As a result, carbon and low-alloy steels were used for portions of the reheater subject to lower temperature ranges, such as the reheater inlet tubes (where the lower temperature steam from the high-pressure turbine exhaust enters the reheater). Intermediate chrome-molybdenum (Cr-Mo) steels were used for portions subject to higher temperatures, such as towards the reheater outlet (where the steam achieves its maximum temperature). Unfortunately, this use of differing materials added an unforeseen failure mechanism to these components—the difficulties of welding dissimilar metals together.

In early reheater designs, the materials selected were not always adequate to address the full range of the conditions that would be experienced, such as varying temperatures during operational upsets, varying physical and thermal stresses, water chemistry conditions, and changes in coal and ash physical and chemical properties. Accordingly, the useful life of these reheaters varied significantly among the many units in the industry because of the differences in operating environments.

In addition to construction materials, the physical design of the reheaters was critical to the actual performance of the components in service. Again, an optimization was required to balance the desired high heat transfer from the gas to steam and the need to avoid undesirably high metal temperatures. Another major factor was the

7 Combustion Engineering Inc., Combustion Fossil Power, 4th edition, 1991, pp. 1-8
8 Babcock and Wilcox, Steam: Its Generation and Use, 40th edition, 1992, pp. 1-8

optimization of available tube surface while maintaining adequate tube spacing to avoid high gas velocities and the resulting excessive erosion of the tube material.

Combined with these design considerations were the coal-ash properties that must be factored into the design in order to avoid fouling and, again, excessive erosion. To manage the fouling conditions, sootblowers were added in some applications. As with the welding of dissimilar metals, installation of sootblowers to reheaters adds a potential failure mechanism to reheater components, namely, erosion caused by sootblower impingement.

Design features similar to those described above are extremely important in determining the life of reheater components. Equally important however is the actual operating environment to which the reheater is subjected. This can probably be best illustrated by examining the most common tube-failure mechanisms experienced in reheaters and the corresponding potential root causes as identified in the Electric Power Research Institute's Boiler Tube Failures: Theory and Practice.[9] See Table 8 which follows.

9 Electric Power Research Institute, Boiler Tube Failures: Theory and Practice, TR-105261

Table 8 Failure Mechanisms in Reheaters (RH)

Failure Mechanism	Possible Root Causes
Short-Term Overheating in RH Tubing	• Tube blockage induced (especially exfoliated oxide blockage) • Maintenance induced (improper chemical cleaning or repairs) • Operation induced (improper startup or shutdown, or overfiring with top heater out of service)
Long-Term Overheating/Creep	• Influences of initial design and/or material choice • Buildup of internal oxide scale • Overheating due to restricted flow caused by chemical or other deposits, scale, debris, etc. • Operating conditions or changes in operation • Blockage or laning of boiler gas passages • Increases in stress due to wall thinning
RH Fireside Corrosion (Sootblower or Ash)	• Influence of overheating of tubes (poor initial design, internal oxide growth during operation, high temperature laning, tube misalignment, operational problems when coal is changed, and rapid startups causing reheater to reach temperature before full steam flow) • Change to coal with unusually corrosive ash • Incomplete or delayed combustion
RH Fireside Erosion	• Improper sootblower operation (control of frequency, temperatures, pressures, and travel; and mechanical malfunctions etc.) • Erosive coal ash characteristics • High gas flow velocities (gas lanes, boiler operation, etc.)
Dissimilar Metal Weld Failures (Failures occur where ferritic and austenitic steels are welded together)	• Excessive tube stresses such as caused by improper initial design or improper tube supports • Excessive local tube temperatures • Change in unit operation (increased unit cycling, change of fuel, redesign of adjacent heat duties) • Initial fabrication defects
Stress Corrosion Cracking	• Influence of environment (mainly contamination from carryover of chlorides from chemical cleaning of waterwalls, boiler water carryover, caustic from attemperator spray, condenser cooling water leaks, or ingress of fireside contaminants or flue gas during primary leaks) • Influence of excessive stresses (especially at supports) • Need to change material to a stabilized grade of stainless steel

These failure mechanisms can occur concurrently or individually. Depending upon the failure mechanisms, different maintenance responses may be required. These range from repair or replacement of individual tubes or tube sections, to redesign and replacement of the reheater, to the installation of equipment that will address the root cause of the maintenance problem (such as sootblowers).

Cumberland Units 1 and 2 Reheater Replacement Case Study

In addition to the Cumberland Unit 1 features described earlier, Cumberland Units 1 and 2 each had 233,200 square feet of reheater surface installed as part of the original construction. During operation of the plant, high wear rates caused by fly ash or sootblower impingement resulted in numerous erosion shields being added and subsequently replaced. Cracks were routinely identified during inspections and were ground out and repaired. Individual tubes were cut out and replaced because of thinning from high-temperature oxidation and coal ash corrosion, mechanical damage, sootblower erosion, or overheating damage. Misaligned tube elements were realigned and numerous support lugs replaced. Still, the reheater condition continued to degrade and require increasing maintenance attention.

In the 1986-1988 period, deterioration of the inlet pendant lower loops led to their being cut out and replaced with SA213-T22 material, a higher chromium content steel that is more resistant to loss of strength with long-term exposure to high temperature. However, the T22 material is susceptible to out-of-service pitting. As a result, these loops were replaced again in 1996.

In 1996, TVA conducted a comprehensive review of the failure experiences in the Cumberland reheaters. The review showed that during the period of fiscal years 1992-1996, eleven leaks had occurred in the Unit 2 reheater pendant tubes. A root cause analysis was performed on the eleven leaks, and several failure mechanisms were identified (including corrosion fatigue, stress corrosion cracking, weld defects, high-temperature oxidation/coal ash corrosion, dissimilar metal welds, and sootblower erosion) with several root causes. Inspections and nondestructive testing indicated that further failures were developing. It was projected that the failure rate would increase and further jeopardize the availability of the unit, potentially causing two forced outages per year by the year 2000.

TVA concluded that, because of the damage that already existed and the overall condition of the existing reheat pendant tubes, the most economical solution was the complete replacement of the 147 inlet and outlet elements. The following items were also recommended:

- Changes in the design of the structural attachments that were welded to the tubes. These attachments were limiting thermal expansions, thereby creating high local stresses that were leading to corrosion fatigue failures. The supports were redesigned and materials changed to reduce or eliminate this mechanism.
- Improvement in the unit's boiler water chemistry program. Condenser tubes were replaced to stop leakage of contaminants from the untreated condenser cooling water into the feedwater system. Also, the feedwater chemistry treatment process was changed to reduce or eliminate water chemistry contributions to the conditions that led to reheater internal tube corrosion.
- Improvement in the welding quality assurance program. Failures had been occurring in field welds and header socket welds. A new welding quality assurance program was implemented to avoid repeats of these failures.

The cost of the element replacement project was estimated to be $8.4 million, with a projected benefit of $2.9 million per year. Thus the project would pay for itself in three years. The recommendations were implemented and the reheater was replaced in 1999.

Experience on the TVA System

Of TVA's currently operating 59 units, 49 use the reheat cycle. In all these units, partial or complete replacement of the components of the reheaters exposed to the flue gas stream has been required in order to keep the units in reliable operation.

Some plants have had different life experiences of the inlet versus the outlet reheater pendants. For example, TVA had to replace the outlet pendant elements at Gallatin

Fossil Plant Units 1 and 2 within 8 to 15 years, while the inlet pendant elements operated for more than 35 years without replacement. Figure 8 below provides a summary of the reheater modification/replacement projects performed on the TVA system. At least one significant portion of the reheater pendant elements in every TVA reheat cycle unit has had to be replaced within 20 to 40 years of initial operation.

Figure 8 TVA Reheater Projects

Other Industry Experience

To assess industry practice in the maintenance of reheaters, TVA analyzed data from other utilities with predominately coal-fired generation. These data represent the maintenance histories of 219 generating units totaling more than 80,000 MW of electrical generation. Of these 219 units, 190 are equipped with reheaters. The results of this analysis are given in Figure 9.

As with the cyclone and the draft system replacement data, these data show no strong correlation between reheater replacement projects and reheater age. Ages at replacement ranged from 5 to 44 years, with a mean age of 25.1 years and a median age of 25 for this data set.

Figure 9 Industry Sampling of Reheater Projects

Of the 190 reheaters included in the sample, there have been 231 reheater replacement projects, with some reheaters having been replaced more than once. As with the cyclone and the draft system replacement data, these data show no strong correlation between reheater replacement projects and reheater age. Ages at replacement ranged from 5 to 44 years, with a mean age of 25.1 years and a median age of 25 for this data set. This leads to the conclusion that factors other than age determine the need for reheater replacement.

Economizer Component Replacement

Economizer Background

Another enhancement to improve the efficiency of the base Rankine thermal cycle was the addition of a heat exchanger in the flue gas stream exiting the steam generator. This heat exchanger, called an economizer, is typically a simple single-phase, tubular heat exchanger with boiler feedwater flowing on the inside and flue gas passing on the outside of the tubes. Thermal energy in the flue gas is transferred across the heat exchange surface into the feedwater, increasing its temperature before it enters the unit's steam drum or the furnace surfaces, depending upon the boiler design.

The economizer provides another useful function by reducing the magnitude of thermal shock caused by feedwater temperature fluctuations at the inlet to either the boiler drum or the waterwalls.[10] Thermal shock, the rapid change in metal temperature due to changes in the fluid temperature, produces stress increases in thick walled boiler components. Large numbers of these stress cycles will ultimately lead to failure of the component.

10 Babcock and Wilcox, Steam: Its Generation and Use, 40th edition 1992, pp. 19-1

The economizer is usually the last heating surface in the flue gas stream before the gas stream exits the steam generator and passes through the combustion air preheater. The overall efficiency of a boiler is improved more by using the thermal energy in the flue gas to heat feedwater than by using it to preheat the combustion air. Sizing an economizer, that is, determining the amount of heat transfer surface to be provided, is an economic optimization among three principal parameters: the cost of the economizer surface, the cost of the air preheater, and the thermal efficiency of the boiler.

The major components of the economizer, in general terms, are the inlet header, the heat exchange tubes or elements, and the outlet header. Since these components are exposed to considerably lower temperatures and a less hostile environment than other boiler components (reheaters and superheaters, for example) they are typically constructed from low-carbon steel to reduce cost. However, because this steel is subject to corrosion in the presence of even extremely low concentrations of oxygen, it is necessary to provide boiler water that is practically 100 percent oxygen-free.[11] This tubing is also susceptible to fly ash erosion and erosion/corrosion.

Thus, as with the reheater, both the physical design and fabrication details of the economizer and the operating conditions it encounters are important factors that determine its useful life. Their importance is again clearly illustrated by the summary of the most common tube-failure mechanisms experienced in economizers and the corresponding potential root causes taken from the Electric Power Research Institute's Boiler Tube Failures: Theory and Practice.[12]

11 Combustion Engineering Inc., Combustion Fossil Power, 4th edition 1991, pp. 5-10
12 Electric Power Research Institute, Boiler Tube Failures: Theory and Practice, TR-105261 Volume 2: Water-Touched Tubes, 1996

Table 9 Failure Mechanisms in Economizers

Failure Mechanism	Possible Root Causes
Corrosion Fatigue	• Influences of excessive stresses/strains (especially restraint stresses at attachments) • Influence of environmental factors (poor boiler water chemistry, overly aggressive or improper chemical cleaning, and/or improper boiler shutdown and/or lay-up procedures) • Influence of historical unit operation (operating procedures that have caused high stresses)
Fly ash or Sootblower Erosion	• Excessive local velocities (geometry of design, distortion or misalignment of tubing rows, misalignment or loss of gas flow guides and baffles, operating above the continuous design rating, and/or operating above design excess air flow) • Increased particle loading (fuel considerations and/or soot-blower operation or maintenance) • Improper sootblower operation (control of frequency, temperatures, pressures, and travel; mechanical malfunctions, etc.)
Thermal fatigue of economizer inlet header tubes	• Operating conditions that produce large through-wall thermal gradients in the header • Header design and construction
Erosion/corrosion in economizer inlet headers	• Very low O_2 levels and high levels of oxygen scavenger
Low-temperature creep cracking	• High stresses (high residual stresses from the cold forming process, enhanced membrane stresses caused by tube ovality, and/or high service stresses)
Fatigue in tubes	• Excessive strains caused by constraint of thermal expansion • Excessive mechanical stresses (poor design or manufacturing) • Vibration induced by flue gas • Poor welding
Pitting in tubes	• Influence of improper shutdown practice (presence of stagnant oxygenated water) • Sagging economizer tubes preventing tube draining after shutdown (presence of stagnant oxygenated water)
Acid dew point corrosion	• Operation of economizer below the acid dew point (SO_2 oxidizes to SO_3 and combines with moisture to form sulfuric acid)

Paradise Unit 3 Economizer Replacement Case Study

Unit 3 of the Paradise Fossil Plant (located on the Green River in Muhlenberg County, Kentucky) is a 1,100 MW (nominal) cyclone-fired unit that were put into service in 1970. It produces steam at 3650 psig, 10030F.

The unit has 281,580 square feet of economizer surface, which was installed as part of the original B&W design and installation. During the first 20 years of unit operation, the reliability of the economizer began to decrease as a result of many of the failure mechanisms addressed in the background discussion. A 1992 review of the generating unit's performance reliability found that tube failures in the economizer was one of the leading causes of forced outages.

A root-cause analysis investigation found numerous failure mechanisms and root causes contributing to these leaks. The predominant failure mechanisms were identified as fly ash erosion, corrosion fatigue, pitting in tubes, and thermal fatigue of economizer inlet header tubes. The root causes were determined to be the following:

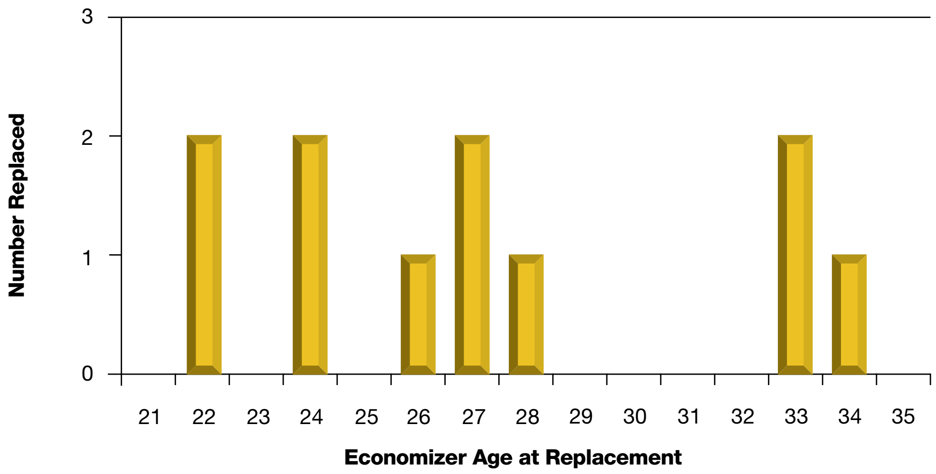
- Poor original design of the economizer (including the baffles).
- Inadequate boiler water treatment and boiler water chemistry control.
- Startup procedures that were allowing slugs of cold water to enter the economizer inlet header.
- Cycling stresses due to forced outages on the unit from other causes.

Measures were implemented to eliminate these root causes or reduce their future impacts. However, past operations had already significantly damaged the economizer elements and inlet header. It was projected that without replacement of most of its components the economizer would increasingly contribute to unit unreliability. It was determined that component failures would, in fact, increase the economizer contribution to unit downtime by approximately 10 percent per year. This equated to a differential cost of replacement power to TVA of $19,543,000 plus the cost of repairs for the fiscal years 1995-1999 period. The total cost to replace the economizer was estimated to be $9,153,000. It was replaced in 1994.

Experience on the TVA System

Of TVA's currently operating 59 units, 44 are equipped with economizers. TVA has replaced all or a significant portion of the economizer elements/tubes on 11 units and has replaced the inlet headers on 3 units. Because of the relatively less severe service conditions of economizers, they have generally experienced longer useful lives than other boiler components discussed above. The TVA history of economizer component replacement projects is provided in Figure 10 below.

Figure 10 TVA Economizer Replacement History



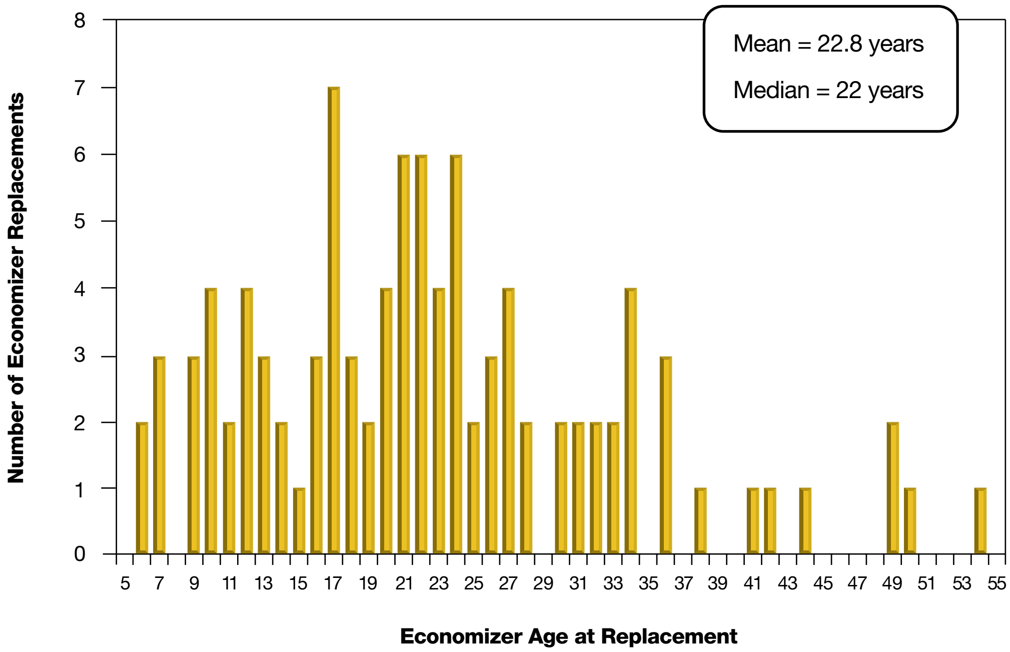
Other Industry Experience

The age analysis of economizer replacement projects for the same industry sample used in the reheater analysis above is presented in Figure 11. Of the 219 units in the sample, 202 are equipped with economizers.

As might be expected, because of the generally less severe service conditions, there have been fewer economizer replacement projects than reheater replacement projects: 98 economizer projects versus 231 reheater projects. However, the average and median ages of the affected economizer at the time of the replacement project are less than the average and median ages of the reheater replacements by 2.3 and 3 years, respectively. The age distribution of the economizer replacements is similar to the reheater age distribution. There is no strong correlation between economizer age and economizer replacement. It is apparent that factors other than age create the situations that lead to economizer replacement.

Figure 11 Industry Sampling of Economizer Projects

The age distribution of the economizer replacements is similar to the reheater age distribution. There is no strong correlation between economizer age and economizer replacement. It is apparent that factors other than age create the situations that lead to economizer replacement.



Conclusions

The Tennessee Valley Authority has, in its more than 65 years of operating electricity-generating plants, established a philosophy of maintenance that has as its objective the safe, reliable, low-cost supply of electricity to the residents of the Tennessee Valley. This maintenance philosophy has been in place and implemented consistently since long before 1972, as is evidenced by the 1972 Gladney-Fox report referenced previously.

The Tennessee Valley Authority has, in its more than 65 years of operating electricity-generating plants, established a philosophy of maintenance that has as its objective the safe, reliable, low-cost supply of electricity to the residents of the Tennessee Valley.

At the core of TVA's philosophy is a thorough evaluation of factors that contribute to loss of reliability and consideration of alternatives to mitigate the loss. The selection of the appropriate alternative is most often based on economic considerations. The selection is also heavily influenced by other factors that are important to TVA, such as employee health and safety. It is common for the selected alternative to be replacement of equipment or components—often with functionally identical equipment or components that reflect improvements in technology and lessons learned from actual service. The many factors that influence equipment or component replacement include design or fabrication errors, unanticipated operating conditions, operational errors, and technology advancements.

Analysis of selected TVA projects that involved replacement of components and systems at TVA generating units does not reveal any strong correlation between the need for replacement and age of the equipment or component. TVA is no different from other electric utilities in its maintenance practices. Others in the industry routinely perform the projects performed by TVA. Furthermore, analysis of data from a large sampling of other utility projects clearly indicates that this routine maintenance behavior—component and equipment replacement—is driven by factors other than unit or component age.

Biographical Notes

Jerry L. Golden is the Senior Manager of Production Technology in the Tennessee Valley Authority's Fossil Power Group. At various times he has served as TVA's Head Mechanical Engineer, Fossil Steam Generation and Equipment; Manager, Advanced Production and Environmental Technology; Manager, Clean Air Program and Generation Technology; Manager, Fossil Engineering; and (Acting) Vice President, Governmental Relations.

Mr. Golden served on the U.S. Environmental Protection Agency's Acid Rain Advisory Committee and chaired the Base Programs Analysis and Policies Work Group of EPA's Clean Air Act Advisory Committee. He currently serves as utility chair of the EPRI advisory committee dealing with post-combustion NOx control and is an advisor on the EPRI boiler performance and SO_2 committees. He also serves on the board of directors of the UtiliTree Carbon Company, an entity formed to implement carbon reduction and sequestration activities for utilities participating in the Climate Challenge Program of the U.S. Department of Energy.