COAL-FIRED POWER PLANT HEAT RATE REDUCTIONS

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PREPARED BY

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1. INTRODUCTION

1.1 PURPOSE

On behalf of Perrin Quarles Associates, Inc. (PQA), Sargent & Lundy, L.L.C. (S&L) performed a study of various methods to reduce the heat rate of existing U.S. coal-fired power plants in a range of sizes–200 MW, 500 MW, and 900 MW. The primary intent of the study was to focus on methods that have been successfully implemented by the utility industry.

The heat rate of a plant is the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output. It is the metric most often used in the electric power generation industry to track and report the performance of thermal power plants. The average, annual operating heat rate of U.S. coal-fired power plants is approximately 10,400 Btu/kWh. The design heat rate of a facility is based on full-load operation with no boiler blowdown, whereas most reported heat rates of operating facilities include performance during off-peak loads and include boiler blowdown. Because operating units report heat rates that include performance at all levels, the numbers are usually significantly higher than the design heat rate.

This study identifies specific plant systems and equipment where efficiency improvements can be realized either through new installations or modifications, and provides estimates of the resulting net plant heat rate reductions and the order-of-magnitude costs for implementation. To conduct the study presented in this report, S&L surveyed available literature, spoke with technology manufacturers, and used its engineering expertise as the basis.

1.2 STUDY SCOPE

The study scope encompassed the following major tasks:

- Discussion of methods to reduce the heat rate of existing power plants.
- Preparation of case studies quantifying heat rate reductions resulting from the methods described herein.
- Survey of existing plants and published literature to assess heat rate reductions typically achieved in the industry.
- Development of order-of-magnitude capital, fixed, and variable operations and maintenance (O&M) cost estimates for the modifications associated with the methods described for typical 200-, 500-, and 900-MW coal plants.

This report addresses the following modifications:

- Major steam turbine modifications, such as replacement of rotors, blades, nozzles, seals and inner and outer casings.
- Major boiler modifications.
- Control systems (digital, online performance monitoring, etc.).
- High-efficiency motors on all major rotating equipment.
- Variable-frequency drive (VFD) motors on all major rotating equipment (usually improves efficiencies at lower than full load).
- Other modifications known to result in substantial equipment and system efficiency gains and plant heat rate reductions.

Based on the above scope, S&L divided the power plant into the following blocks and identified possible methods for efficiency improvement and heat rate reductions in the following areas:

- Boiler island
  - Coal transport, conveying, and grinding
  - Boiler operation/overhaul with new heat transfer surface
  - Neural network (NN) control system
  - Intelligent sootblower (ISB) system
  - Air heater
- Turbine island
  - Turbine
  - Feedwater heater
  - Condenser
  - Turbine drive/motor-driven feed pump
- Flue gas system
  - Forced draft (FD) and induced draft (ID) fan improvement
  - Variable-frequency drive (VFD)

- Air pollution control equipment
  - Flue gas desulfurization (FGD) system
  - Particulate system
  - Selective catalytic reduction (SCR) system
- Water treatment system
  - Boiler water treatment
  - Cooling tower

This report discusses potential efficiency improvement concepts and the resulting heat rate reductions that can be implemented in various systems of a typical coal-fired power plant. All estimated capital and installation costs are referenced from work in progress and vendor quotes as of the year 2008. The costs represent values of new equipment purchased in the year 2008. S&L cautions that the costs presented herein are not indicative of those that may be expected for a specific facility due to variables such as equipment, material, and labor market conditions and site specifications. However, these cost estimates provide valuable information for comparative purposes when evaluating the advantages and disadvantages of the various concepts. The costs should not be used as a basis for project budgeting or financing purposes.

For budgeting or financing purposes, S&L recommends site-specific evaluations and cost analyses based on actual market conditions for any and all required equipment, material, and labor at the time of the project.

2. BOILER ISLAND

This section of the report discusses modifications to systems and equipment within the boiler island that offer potential improvements in plant heat rate:

- Materials handling
- Boiler operation/overhaul with new heat transfer surface
- NN control system
- ISB system
- Air heaters

2.1 MATERIALS HANDLING

The coal handling portion of a power plant can encompass every piece of equipment from rail, truck, or barge unloading to the conveyors, crushers, and storage bins. The equipment generally operates intermittently for a set number of hours each day and does not consume a significant amount of energy. An estimated, typical power requirement as a fraction of total gross power plant output is 0.07%. Improvements to the process efficiency are limited primarily to the motors and drives. As the drives deteriorate in function and performance, they can be replaced with more energy-efficient motors. Additionally, VFDs are already used for certain applications within the coal handling equipment, but for reasons other than efficiency at low turndown. Specifically, VFDs are used to reduce excess strains on equipment, such as belts and conveyors during startup, and their application for reducing energy demands at turndown is not significantly applicable due to the intermittent operation of the coal handling equipment. Although VFDs provide more precise control of the operating equipment, which can be considered an efficiency improvement, the reduction in overall plant heat rate is not substantial.

Coal pulverizers are used to provide fine coal particles for pneumatic transport into the boiler for combustion. Fine coal particles improve the combustion efficiency of a boiler. The improvement in combustion reduces the amount of coal that must be transported and burned in the boiler and thereby reduces fuel cost and the plant heat rate. Improvements to pulverizer designs have enabled more finely ground coal and a lower primary air pressure drop through the pulverizer.[Ref. 49] Such improvements can also be incorporated on older existing units, but may result in a loss in mass throughput. This reduction in throughput is generally greater than the fuel use savings from enhanced coal fineness, thereby reducing the capacity of the pulverizer. If a plant has excess pulverizer capacity, such improvements can be implemented. If the facility is switching fuels, then such upgrades are probably warranted. But, based on historical projects, this area of improvement has not yielded significant reductions in plant heat rate unless the machinery was severely degraded. The costs associated with such projects are significant.

The ash handling system presents some opportunities to switch from a water-sluicing bottom ash system to a dry drag chain system, which can save some power and water for the plant. But, in general, ash handling equipment is another area of material handling that does not present much opportunity to economically reduce auxiliary power requirements. An average of the power consumed by ash handling equipment as a percentage of total gross plant power consumption is 0.1%. The equipment operates intermittently, similar to the coal handling equipment and, therefore, is not considered a prime area of investment for plant heat rate reduction.

2.2 BOILER OPERATION/OVERHAUL WITH NEW HEAT TRANSFER SURFACE

The furnace of a power plant is the most significant aspect of a facility affecting the thermal performance, aside from the steam turbine generator. The design of furnaces in the 1950s through the 1970s typically was based on a specific design fuel and the premise that it would operate at base load. Today's competitive electric utility market has required a number of facilities to begin operating units originally designed for base load as cycling units to maximize profits. Additionally, replacement of the original design coal with lesser-valued fuels is more common today to reduce operating costs and/or to economically meet environmental emissions requirements. These two system changes have required major alterations to power plants in order to maintain the highest plant output and lowest plant heat rate.[Refs. 33, 38, 39]

During the initial study phase in which a plant considers options for a fuel switch, it looks at many opportunities for upgrading the furnace to enhance its efficiency in using an off-design fuel or fuel blend. These opportunities generally entail the replacement of older equipment, piping, and headers with more advanced designs and materials to improve the performance of the furnace. Additional tubing may also be added to increase the surface area for either enhanced steam production or quality. However, if not properly designed, the changes to the boiler may result in problems with the furnace such as: variances in radiant absorption and consequent overheating in certain areas of the furnace, reduced steam flow or water circulation, flow instabilities, inefficient water-steam separation, inefficient reheat temperatures, and ash and slag buildup, which may result in higher heat rates than estimated.

Generally, a plant makes incremental changes to a furnace to maintain the unit, but large investments, such as major furnace upgrades are not undertaken solely for efficiency improvement and heat rate reduction purposes due to regulations currently in place. Therefore for Owners seeking significant efficiency improvements with a power plant including the boiler, it is more economic to simply build a new, more efficient, power plant. For these reasons, a potential reduction in heat rate was not included here for major boiler upgrades since such upgrades generally occur during a fuel switch. Moreover, such upgrades entail entirely new design efficiencies for the furnace because the new fuel is generally substantially different from the original design fuel. Therefore, a comparison of before/after heat rates would not accurately represent a potential for heat rate reduction.

However, there have been cases in which the economizer has been degraded to such an extent that it required replacement. Such economizer replacements do occur during some selective catalytic reduction (SCR) retrofit projects. Because the SCR design is dependent on the temperature of the flue gas being controlled below a specific temperature, a specific plant may be operating with a higher economizer exit gas temperature, which would require a new or upgraded economizer section to lower the gas temperature for an SCR retrofit project. The temperature reduction may range from 20-40°F, which can yield substantial heat rate recoveries or reductions in heat rate of 50-100 Btu/kWh.[Refs. 2, 3, 4, 12, 49] Table 2-1 summarizes the estimated costs and heat rate reductions associated with installing economizers on typical power plants. The O&M costs represent positive increments above the original equipment due to expenses incurred by maintaining the condition of the extra surface area of tubing by using steam sootblowers.

Table 2-1. Summary of Economizer Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	50-100	50-100	50-100
Capital cost, $ million	2-3	4-5	7-8
Fixed O&M cost, $/yr	50,000	100,000	150,000
Variable O&M cost, $/yr	0	0	0

2.3 NEURAL NETWORK

Developments in data acquisition technology and the associated software programs and computer processors have steadily enhanced techniques available to optimize power plant control. The field of process control has rapidly expanded into the power production field and covers areas of plant operation such as burners, sootblowers, coal feed, steam flows, and environmental equipment. Computer models, known as NNs, are now able to simulate the power plant at various static and dynamic loads, with the predicted performance results correlated to several real-time process measurements. As the models are updated, the control system more accurately predicts power plant performance during various load changes, improving overall efficiency and reducing detrimental conditions of stress on the plant.

There are a number of NN systems offered by vendors in the industry. These systems basically operate in a similar fashion but differ in terms of complexity. In general, an NN system ties into the distributed control system (DCS) for data input and control and uses proprietary modeling and control modules that have been developed specifically for the plant with operator input. NN systems have been installed on more than 300 boilers in the U.S., primarily for burner optimization and NO_X control and heat rate improvement. A specific application of the NN system would be for combustion control to limit NO_X and CO emissions. These emissions tend to increase as the plant undergoes rapid load changes and it is this area of operation where model predictive control (MPC) modules drastically improve plant emissions performance. Optical combustion monitoring systems often will help supply the necessary information to the NN system and combustion optimization module to provide real-time, adaptive control to prevent emissions spikes during load-following operation. Other areas of optimization include control of excess O_2, superheat and reheat steam temperatures, superheat and reheat steam spray flows, and operation of the SCR and flue gas desulfurization (FGD) systems based on NO_X and SO_2 levels.

Controlling excessive superheat and reheat steam temperatures is of paramount importance in preventing mechanical degradation of the boiler tubes. Similarly, excessive steam temperatures require tempering, which reduces plant thermal performance. NN systems provide adaptive control modules to provide burner tilt and steam tempering to properly balance plant steam response to load changes.

Depending on the complexity of the NN system applied and on the quality of DCS installed at a power plant, the improvement in heat rate can be significant. The expected range of improvement in boiler efficiency is 0-1.5%pt. Refs. 9, 16, 18, 26, 27, 34, 38, 44, 52, 53

The estimated capital cost to implement NN technology ranges from $500,000 to $750,000, depending on the existing automation. Factors that can increase the cost of an NN system are the age and condition of the existing DCS. The cost includes hardware and installation time for the NN system only. Table 2-2 summarizes the NN heat rate reductions and costs. The O&M expenditures are representative of software updates, onsite training, and computer hardware replacement.

Table 2-2. Summary of NN Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	50-150	30-100	0-50
Capital cost, $ million	0.5	0.75	0.75
Fixed O&M cost, $/yr	50,000	50,000	50,000
Variable O&M cost, $/yr	0	0	0

2.4 INTELLIGENT SOOTBLOWERS

The use of ISB systems for improving system efficiency also enhances the performance of the furnace and longevity of the tubing material, while minimizing cycling effects to the steam turbine. The ISB system functions by monitoring both furnace exhaust gas temperatures and steam temperatures. A sophisticated ISB will receive various inputs from the boiler system, which are then digitally processed to evaluate real-time performance. The ISB system then interacts with the DCS, plant historian, or other data acquisition systems, to strategically allocate steam to specific areas to remove ash buildup. As soot and ash build up on heat transfer tubing, from the superheaters to the economizers, the transfer of heat from flue gas to the tubing is reduced, adversely affecting steam conditions. The ISB uses the real-time data to identify affected areas that require soot blowing. Traditional sootblowing systems depend on power plant operator directions and generally are used on a specified-time basis. Overuse of sootblowers erodes the boiler tubing and wastes steam that could be used in the power cycle. Sootblowing improvements affect performance at both full-load and turndown, since less steam is removed from the power cycle.[Refs. 37, 39, 45, 52, 53, 54]

The boiler efficiency improvements obtained by installing ISB systems on older boilers have ranged from 0.3-0.9%pt. For units firing PRB coals and lignite where slagging and fouling result in a large, rapid decrease in thermal efficiency, the boiler efficiency improvement may be as high as 1.5%pt.[Ref. 9] The specific performance improvement depends on the type of fuel used and the age of the furnace.[Ref. 3] The average gain in boiler efficiency is approximately 0.6%pt, which translates to a reduction in net heat rate of 60 Btu/kWh for a plant that installs an ISB system.[Ref. 32]

The cost to implement an ISB system is relatively inexpensive if the necessary hardware is already installed, such as the sootblowers, steam lines, controls, etc. The system comprises proprietary software, and the majority of man-hours expended to implement the system are for effectively engaging the current DCS with the ISB system controls. The cost to install an ISB system ranges from $300,000 to $500,000 and is not affected by the size of the boiler unit. The annual operating cost would be approximately $50,000. The separate improvements obtained via NN and ISB systems are not necessarily cumulative. The overall improvement via either system could be nearly the same as that achieved by the use of an advanced NN system integrated with an ISB system. The O&M expenditures are representative of software updates, onsite training, and computer hardware replacement.

Table 2-3 summarizes the ISB heat rate reductions and costs.

Table 2-3. Summary of ISB Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	30-150	30-90	30-90
Capital cost, $ million	0.3	0.5	0.5
Fixed O&M cost, $/yr	50,000	50,000	50,000
Variable O&M cost, $/yr	0	0	0

2.5 AIR HEATERS

Air pre-heaters are paramount in maintaining a highly efficient power plant. Such systems provide heat recovery to the unit by cooling the flue gas counter-currently with cool incoming pre-combustion air. Cooling of the flue gas transfers the heat that is necessary both for coal drying and overall boiler efficiency. The air pre-heater is located downstream (flue gas path) of the economizer. There are two primary types of air pre-heaters - regenerative, rotating-type and recuperative, stationary-type. The stationary-type generally is classified as tubular or plate, with more advanced systems using heat pipes. The majority of air pre-heaters used with utility-scale boilers is the regenerative design, which is the type discussed in this report. Two methods are identified for air heater improvement, either singly or in combination:

- Limit air heater leakages to 6% of incoming air flow
- Lower air heater outlet temperature by controlling acid dew point

2.5.1 Limit Air Heater Leakage

The most common, regenerative air pre-heater used on utility plants is the Ljungström type. The heat exchanger is a cylindrical container filled with corrugated metal consisting of carbon steel in the hotter regions of the flue gas path and either an alloy- or enamel-coated carbon steel material at the cooler end due to acid deposition. The cylinder rotates during operation, absorbing heat from the hot flue gas and transferring it to the counter-flowing, cold pre-combustion air. The cylinder rotates on an axle. Ductwork manifolds on the top and bottom direct air and flue gases into separate portions of the cylinder. A major difficulty associated with the use of regenerative air pre-heaters is air leakage from the higher-pressure pre-combustion air side to the flue gas side.[Ref. 49] Generally, the combustion air leaks across the faces of the rotating section, thus bypassing the boiler and flowing out on the flue gas side. A second area of air leakage is around the outer perimeter of the cylinder.[Refs. 36, 49] Leakage affects boiler efficiency due to lost heat recuperation. Fans are affected by the leakage since the combustion air requirement is fixed and any leakage requires additional fan capacity. The forced draft (FD) and induced draft (ID) fan must operate at higher capacities due to the increased flow incurred by the air bypassing the furnace.

Commissioning of air pre-heaters generally results in air leakage from the combustion air side to the flue gas side in the range of 5-15%, with the higher percentages representative of older style air heaters. As a unit ages, the percentage of air leaking past the seals increases, which lowers the plant efficiency due to the increase of air flow sent through the FD fans to maintain sufficient O_2 levels in the boiler. The increased air flow raises the auxiliary power consumption of the FD fan; and if ID fans are used, even more auxiliary power is required to transfer the extra air through the flue gas ductwork, emissions control equipment, and stack. Air leakage measurements are difficult to accurately quantify and usually underestimate the actual leakage rate due to improperly located flow sensors. The effects of air pre-heater leakage are evident in the loads on the fans as compared to the original design loads if all other leakages are taken into account.

Regulatory mandates to retrofit existing units with environmental controls such as SCR, FGD, or baghouses, have increased the auxiliary power needed to force the boiler flue gas through the added ductwork and emissions control equipment. The increased fan power generally requires a booster fan to be installed or possibly new ID fans if the plant does not already have an existing FGD system. If the air pre-heater allows a substantial amount of leakage and that is not addressed, the extra gas flow will increase the power consumption of either the new ID fans or booster fan more than necessary.

Improvements to seals on regenerative air pre-heaters have enabled the reduction of air leakage to roughly 6%.[Ref. 2, 11] The improved seals offered by vendors are applied to the sectors, outer perimeter, and rotor section. The range of heat rate reductions that may be achieved by reducing air heater leakage varies significantly from unit to unit, but is approximately 10-40 Btu/kWh. If substantial improvements to a unit are implemented that include new environmental control technology, which results in an increase in flue gas pressure drop, then reducing the air heater leakage can decrease the plant heat rate by even more.[Refs. 29, 30, 40, 41, 43]

Table 2-4 summarizes the air heater and duct leakage control heat rate reductions and costs.

Table 2-4. Summary of Air Heater and Duct Leakage Control Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	10-40	10-40	10-40
Capital cost, $ million	0.3-0.5	0.6-0.7	1-1.2
Fixed O&M cost, $/yr	50,000	75,000	100,000
Variable O&M cost, $/yr	0	0	0

2.5.2 Lower Air Heater Outlet Temperature by Controlling Acid Dew Point

The air heater outlet temperature typically is controlled at 20-30°F above the sulfuric acid dew point to prevent corrosion of cold-end baskets. The use of SCR results in an increase in SO_3 concentration, requiring plants to control SO_3 to avoid blue plume formation. This typically is the case for most of the medium- to high-sulfur bituminous coals. Most of these installations are being retrofitted with either Trona or a hydrated lime injection system. A number of sorbent injection system suppliers advocate the use of these sorbents to lower the dew point even below the pre-SCR operating conditions to permit extracting heat from the flue gas. If the existing air heater is sized conservatively, then there may not be any air heater modifications required to achieve a lower temperature; however, in most cases air heater modifications will be required. Typically, every 40°F reduction in air heater outlet temperature will result in a boiler efficiency improvement of 1%pt.

Table 2-5 summarizes the acid dew point control heat rate reductions and costs. The ranges listed are based on no air heater modification to full air heater replacement, along with a Trona injection system. The O&M costs represent the incremental costs associated with both the increased surface area and injection system.

Table 2-5. Summary of Acid Dew Point Control Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	50-120	50-120	50-120
Capital cost, $ million	1.5-3.5	2.5-10.0	3.5-18
Fixed O&M cost, $/yr	50,000	75,000	100,000
Variable O&M cost, $/yr (function of SO_3 removed)	170,000-350,000	425,000-850,000	750,000-1,500,000

3. TURBINE ISLAND

This section of the report discusses modifications to systems and equipment within the turbine island that offer potential reductions in plant heat rate:

- Turbine overhaul
- Feedwater heaters
- Condenser
- Turbine drive/motor-driven feed pumps

3.1 TURBINE OVERHAUL

Technological advancements have improved the efficiency and longevity of steam turbines. Advanced design tools, such as computational fluid dynamics (CFD), have significantly enhanced turbine designer capabilities to increase the efficiency of turbines. Additionally, development of materials with improved properties has enabled the implementation of more efficient designs through fabrication of more geometrically complex components. The improved turbine components have also provided a means to increase the efficiency of older turbines that are less efficient and have experienced losses in performance due to degradation.[Refs. 19, 21, 23, 31, 33, 35, 47, 48, 50]

The greatest amount of improvement would be achieved from upgrading a turbine that has experienced significant deterioration and has performed well below the design level. Significant increases in performance can be gained from turbine upgrades when plants experience problems such as steam leakages or blade erosion. In such cases, except for the outer casing, the entire turbine might have to be replaced, which would yield improvements in turbine efficiency above 5%pt and, in extreme cases, can be over 10%pt. Such large improvements (>10%pt) in efficiencies are not the norm in the industry.

The typical turbine upgrade depends on the case history of the turbine itself and its overall performance. The upgrade can entail myriad improvements, all of which affect the performance and associated costs. For the average unit that has undergone an upgrade, and is approximately 500-MW and 30 years old, the typical performance improvements of the high-pressure (HP) and low-pressure (LP) units range from 2-3%pt and the intermediate-pressure (IP) units range from 1-2%pt, totaling 2-3% in overall power generation. These upgrades take into account the loss in performance over time (degradation). If the improvements are compared with the original design basis, they generally range from 1-2%pt for the HP and LP units and 1%pt for the IP units, totaling 1-2%pt in overall power generation.[Refs. 2, 6, 14, 21]

In general, there have been few retrofits of small units, mainly due to the costs involved. However, benefits similar to those achieved for large turbines (>500 MW) would be expected.

Table 3-1 summarizes the turbine overhaul heat rate reductions and costs. The heat rate reductions listed are a function of their associated costs and represent the most realistic values that utilities have been willing to consider. Future upgrades may be more extensive due to the current lack of new construction and the delays inherent in obtaining new construction permits.

Table 3-1. Summary of Turbine Overhaul Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	100-300	100-300	100-300
Capital cost, $ million	2-12	4-20	5-25
Fixed O&M cost, $/yr	0	0	0
Variable O&M cost, $/yr	0	0	0

3.2 FEEDWATER HEATERS

Feedwater heaters are used within a power plant's thermal cycle to improve overall efficiency. The number and placement of feedwater heaters are determined during the original plant design and are highly integrated with the overall performance of the steam turbine. Feedwater heaters preheat the boiler feedwater prior to it entering the boiler for steam generation. The heat used to increase the feedwater temperature comes directly from the thermal cycle, as steam extracted from various turbine sections.

The feedwater heaters in a power plant are either LP or HP shell and tube heat exchangers. From an efficiency standpoint, the primary means of improving the operation of such heat exchangers is to maintain their operational effectiveness. Feedwater heating surface could be added to improve efficiency. However, the costs associated with either increasing the heat transfer surfaces of existing heaters, or adding additional heaters for efficiency purposes only, is prohibitive due to the small incremental reductions in heat rate that would be obtained.

3.3 CONDENSER

Effective operation of the steam surface condenser in a power plant can significantly improve the heat rate of a unit. In fact, in many cases it can pose the most significant hindrance to a plant trying to maintain its original design heat rate. Since the primary function of the condenser is to condense steam flowing from the last stage of the steam turbine to liquid form, it is most desirable from a thermodynamic standpoint that this occurs at the lowest temperature reasonably feasible. By lowering the condensing temperature, the backpressure on the turbine is lowered, which improves turbine performance. A condenser degrades primarily due to fouling of the tubes and air in-leakage. Tube fouling leads to reduced heat transfer rates, while air in-leakage directly increases the backpressure of the condenser and degrades the quality of the water. If once-through cooling is used, fouling of condenser tubing can be substantial. But if a closed cooling system is used, cooling water quality can be controlled to a much higher degree.

Condenser tube cleaning can be performed while the unit is on line or off line. Generally, the historical standard method of online cleaning has been to use circulating rubber sponge balls that flow through the condenser tubes with the coolant. Frictional contact between the balls and tubing scrapes away most of the fouling accumulated on the inside of the tubes. The balls are circulated through the condenser for a few hours each day.

Because the use of sponge balls for cleaning condensers can involve adverse side effects, such as the plugging and erosion of the tubing (especially on older condensers), the method is not always practical for all power plants due to the type of fouling that may be occurring. Furthermore, if a plant does not have adequate personnel to properly maintain the cleaning system, it may be removed in some cases. If a plant’s condenser cooling system was not originally designed with a sponge ball system, then installing a new cleaning system can be very costly compared to other alternatives. Under these circumstances, a plant may find that installing a new condenser is financially warranted. Today’s condensers are designed more efficiently to reduce circulating water pressure drop and to enhance the cooling and condensing of the steam turbine exhaust. The materials of construction are more resilient towards erosion from cleaning and corrosion. Additionally, the newly designed condensers can reduce stress induced failure due to cycling service.

The offline or reduced-load cleaning method that is most effective uses manual techniques involving brushes, HP water lances, or projectile cleaners (metal pigs or “cleaners”). The metal cleaners are forced through tubes with pressurized water (~300 psig) to scrape away deposits by frictional contact. Plastic cleaners are not as effective as metal cleaners, and a cleaning regime using both methods may be applied. Metal cleaners tend to produce the best results, but this can depend on the specific type of fouling. This mechanical cleaning method can improve heat transfer rates in the condenser to near-design values and substantially improve condenser backpressure. Metal brushes unfortunately tend to erode the tubing, but plastic brushes can be used instead. Mechanical cleaning can be performed on line but at reduced load depending on the condenser arrangement. If this is not feasible, the unit must be taken off line for condenser cleaning.[Refs. 5, 42, 46]

Brush cleaning can improve the condenser backpressure by approximately 0.1 in. Hg and a mechanical cleaning can improve it by as much as 0.6 in. Hg or more. An average cleaning schedule that is properly implemented can reduce the backpressure on a once-through condenser by about 0.35 in. Hg, resulting in heat rate reduction of approximately 30-70 Btu/kWh. Facilities using a regular condenser cleaning schedule may achieve more significant heat rate reductions, depending on fouling characteristics at a particular plant location.

A full economic analysis must be performed to determine which offline cleaning method is to be used. Such an analysis would result in an optimum offline or reduced-load cleaning schedule that could average between two and three cleanings a year. These analyses consider inputs such as operating data, plant performance, loads, time of year, etc., to accurately assess cleaning schedules for optimum economic performance.[Ref. 42]

An average cleaning for a 500-MW plant with once-through cooling takes about for days and can cost $30,000-$80,000, including labor, materials, and waste disposal. The majority of this cost is for labor and can vary significantly by region. Table 3-2 summarizes condenser heat rate reductions and costs.

Table 3-2. Summary of Condenser Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	30-70	30-70	30-70
Capital cost, $	0	0	0
Fixed O&M cost, $/yr	30,000	60,000	80,000
Variable O&M cost, $/yr	0	0	0

3.4 BOILER FEED PUMPS

The boiler feed pumps consume a large fraction of the auxiliary power used internally within a power plant. Boiler feed pumps pressurize and force feedwater through the HP feedwater heaters and boiler. Boiler feed pumps can require power in excess of 10 MW on a 500-MW power plant, therefore the maintenance on these pumps should be rigorous to ensure both reliability and high-efficiency operation.

Boiler feed pumps wear over time and subsequently operate below the original design efficiency. The most pragmatic remedy is to rebuild a boiler feed pump in an overhaul or upgrade. The overhaul of the pumps is justifiable in the industry and can yield heat rate reductions estimated to be in the range of 25-50 Btu/kWh. The estimated cost to rebuild the boiler feed pumps for a power plant unit ranges from $250,000 to $800,000.

Table 3-3 summarizes condenser heat rate reductions and costs.

Table 3-3. Summary of Boiler Feed Pump Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	25-50	25-50	25-50
Capital cost, $ million	0.25-0.35	0.5-0.6	0.7-0.8
Fixed O&M cost, $/yr	0	0	0
Variable O&M cost, $/yr	0	0	0

4. FLUE GAS SYSTEM

This section of the report discusses modifications to the flue gas system that offer potential improvements in plant efficiency:

- Improved FD and ID fan efficiency
- VFDs

4.1 ID FANS

The emissions requirements set forth by the U.S. EPA affecting coal-based power plants have required many older units to comply by implementing various control technologies. Such emissions requirements have required the reduction of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). Because the technologies that are required to reduce the emissions are add-on back-end flue gas cleanup systems, the overall flue gas system pressure drop is increased substantially. The increased pressure required to maintain proper flue gas flow requires additional fan power, which can be achieved by an ID fan upgrade/replacement or an added booster fan.

Generally, older power plant facilities were designed and built with centrifugal fans. In more recent years, axial fans have been used both for retrofits and new designs.[Ref. 8] Axial fans by design are more efficient than centrifugal fans at various turndown levels from their design point.[Ref. 49] The primary physical difference between centrifugal and axial fans is that the centrifugal fans accelerate the air flow in a radial direction and the axial fans in the axial direction, as the name implies. Generally, axial fans use inlet or outlet vanes, in which case they are referred to as *vane axial* fans. Axial fans provide more flexibility in design due to their lower inherent mass with respect to a comparable centrifugal fan, and the fact that they can be used in line with the ductwork either horizontally or vertically.

There are several methods of controlling flue gas flow with a fan:

- Single-speed motors with variable inlet vanes (VIVs) as a throttling mechanism
- Variable-speed as either a fluid-coupling or VFD
- Two-speed motor with damper or VIV
- Variable-pitch blades (VPBs)

In the past, dampers have been the predominant means for flow control, but they are the most inefficient method and are not cost-effective for today's plants. The most precise and energy-efficient method of flue gas flow control is use of VFD. The VFD controls fan speed electrically by using a static controllable rectifier (thyristor) to control frequency and voltage and, thereby, the fan speed. The VFD enables very precise and accurate speed control with an almost instantaneous response to control signals. The VFD controller enables highly efficient fan performance at almost all percentages of flow turndown. But the VFD fan control also entails the highest capital cost of all control methods.

It has been the trend that the two competing fan systems for upgrades on new plants are centrifugal fans with VFD or axial fans with VPB when the plant wants to minimize operating costs and maximize efficiency. Both types of fans produce the most efficient performance at the maximum continuous rating (MCR) of the boiler. At MCR the axial fan can provide an approximately 1-80 Btu/kWh heat rate reduction, depending on whether all fans or just the ID fans are of the axial design.

The cost differential to use either fan on a retrofit project can be greatly influenced by the existing ductwork configuration and necessary changes to accommodate the new emissions control equipment. The ductwork modification costs in themselves can dictate which fan is selected. A specific plant's operating regime, regarding percentages of time spent at various loads, differently affects the overall operating cost of each fan. O&M costs also differ substantially because axial fans with VPB require extensive maintenance.

Table 4-1 summarizes potential average fan heat rate reductions and costs.

Table 4-1. Summary of ID Axial Fan (and Motor) Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	10-50	10-50	10-50
Capital cost, $ million	6-6.5	9-11	15-16
Fixed O&M cost, $/yr	50,000	85,000	130,000
Variable O&M cost, $/yr	0	0	0

If the plant is base-loaded, axial fans may prove more efficient than centrifugal fans with VFDs. A case study on a selection of fans is presented in section 8 of this report.

4.2 VARIABLE-FREQUENCY DRIVES

Due to current electricity market conditions, many units no longer operate at base-load capacity and, therefore, VFDs, also known as variable-speed drives (VSDs) on fans can greatly enhance plant performance at off-peak loads. Additionally, because utilities are phasing in their environmental equipment upgrades, new fans are oversized and operated at lower capacities until all additional equipment has been added. Under these scenarios, VFDs can significantly improve the unit heat rate.

VFDs as motor controllers offer many substantial improvements to electric motor power requirements. The drives provide benefits such as *soft starts*, which reduce initial electrical load, excessive torque, and subsequent equipment wear during startups; provide precise speed control; and enable high-efficiency operation of motors at less than the maximum efficiency point.[Refs. 28, 51] During load turndown, plant auxiliary power can be reduced by 30-60% if all large motors in a plant were to be efficiently controlled by VFD. With unit loads varying throughout the year, the benefits of using VFDs on large-size equipment, such as FD or ID fans, boiler feedwater and condenser circulation water pumps, can have significant impacts. Because plants today usually use either new booster ID fans or new ID fans, the option of investing in VFDs generally appeals to plant operators since they are incurring long outages to install the either new or additional air emission controls equipment. Depending on plant configuration, the improvement in heat rate can range from 20-100 Btu/kWh. There are circumstances in which the heat rate improvement has been estimated to be much higher, depending on the operation of the unit. Cycling units realize the greatest gains representative of the upper range of heat rate improvement, whereas units which were designed with excess fan capacity will exhibit the lower range. Heat rate improvements will vary when the VFD is compared to a single- or dual-speed motor with VIVs. Table 4-2 summarizes potential improvement associated with installing new VFDs for use with ID fans. The costs associated with the O&M portion of the VFDs account for partial electronics replacement and can vary significantly due to a vendor’s commercial offering.

Table 4-2. Summary of VFD (only) Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	20-100	20-100	20-100
Capital cost, $ million	1.5-2	3-4	5-6
Fixed O&M cost, $/yr	20,000	30,000	50,000
Variable O&M cost, $/yr	0	0	0

In summary, the combined overall heat rate improvements and associated capitals costs for upgrading a plant with new centrifugal fans and VFDs are listed in Table 4-3.

Table 4-3. Summary of Combined VFD and Fan Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	10-150	10-150	10-150
Capital cost, $ million	6-6.5	9-11	15-16
Fixed O&M cost, $/yr	25,000	38,000	60,000
Variable O&M cost, $/yr	0	0	0

The use of VFDs are also applicable with boiler feed water pumps as mentioned previously. Generally, if a unit with an older steam turbine is rated below 350 MW the use of motor-driven boiler feedwater pumps as the main drivers may be considered practical from an efficiency standpoint. If a unit cycles frequently then operation of the pumps with VFDs will offer the best results on heat rate reductions, followed by fluid couplings. The use of VFDs for boiler feed pumps is becoming more common in the industry for larger units. And with the advancements in LP steam turbines, a motor-driven feed pump can actually improve the thermal performance of a system up to the 600-MW range versus turbine drive pumps. As for smaller and older units, an upgrade to a VFD boiler feed pump drive generally does not occur due to high capital costs.

5. EMISSIONS CONTROL TECHNOLOGIES

To meet environmental regulations, it has been regular practice for plant operators to implement emissions control technologies. Among the typical technologies used in the industry are the three discussed in this section of the report:

- FGD system
- Particulate control system, e.g., electrostatic precipitators (ESP)
- SCR system

These types of control technologies can consume relatively large amounts of auxiliary power. For example, a wet FGD system typically requires 2-3% of the gross electrical output of a plant when the unit is combusting a high-sulfur coal. In addition to general auxiliary power required to operate the apparatus, optimal performance may not be realized due to natural wear on the system, inadequate maintenance, inefficient operation practices, and/or poor operating conditions. Small adjustments or modifications can be made to these systems to alleviate a portion of the electrical requirements necessary to accommodate these inefficiencies. Generally, FGD systems and ESPs are technologies that can be modified to have the greatest impact on power consumption, while concurrently meeting emissions collection requirements.[Refs. 20, 25]

The modifications to SCR systems generally entail optimizations to reduce flue gas pressure drops. Some optimizations may be realized in the extensive ductwork usually involved with SCR retrofits and in other cases, lower pressure drop catalysts are developed by vendors. In lesser amounts, auxiliary power may be reduced by changes in the vaporization or mixing scheme of the SCR system.

5.1 FGD SYSTEM

Areas and means of potential improvement within an older FGD system are:

- Removal of venturi throat
- Improved flow distribution to lower the pressure drop across FGD
- Spray header operation
- Use of VFDs

5.1.1 Removal of Venturi Throat

The designs of older coal-fired power plants commonly incorporated a venturi quencher prior to the absorber tower to reduce the temperature of the flue gas prior to entering the desulfurization module. The venturi scrubber has a converging section, in which the cross-sectional area is effectively decreased, causing an increase in fluid velocity. This high-energy flue gas stream is introduced to quenching liquid, resulting in an effective barrier/mixing regime that prevents hot gas from reaching the rubber-lined walls of the sump and absorber. Although a venturi is particularly effective at quenching the flue gas stream, it is at the expense of additional flue gas pressure losses. The resistance to flue gas flow incurred by the venturi quencher increases the power necessary to operate the ID fans. To mitigate the flue gas flow resistances of a venturi quencher, a co-current spray tower quencher may be used instead.

In a recently completed study for a 440-MW unit, the pressure drop across the venturi quencher alone was 6 inches water column (in. w.c.). Because the unit was fan-limited during certain operating conditions, the pressure drop across the quencher was considered a potential opportunity for efficiency improvement. A co-current, open-spray quencher was designed to remedy the severe pressure losses. This resulted in the unit recovering 3 in. w.c., with an associated delivery and installation cost of approximately $2.5 million. This reduction in pressure loss across the quencher recovered 584 kW of power at the ID fan, which equated to a reduction in plant heat rate of approximately 13 Btu/kWh.

5.1.2 Addition of Turning Vanes/Perforated Gas Distribution Plates

Improving gas flow distribution can have several advantages. One advantage is that an even flow distribution into an absorber can increase the amount of flue gas coming in contact with the absorber sorbent and thus increase SO_2 capture. Additionally, properly directed flue gas can eliminate persistent maintenance costs due to system component erosion. Another advantage is that improved flow distribution can reduce the amount of energy expended by the flue gas to navigate through turns in the ducting, which will reduce the power required by the ID fan and thereby reduce operating costs.

A study based on computational fluid dynamics (CFD) modeling was performed to investigate possible upgrades on a 450-MW wet FGD system with multiple absorbers. The study revealed that a possible upgrade entailed the installation of turning vanes and perforated gas distribution plates at the inlet duct to the absorbers to improve the flue gas flow into the third absorber. The vanes provided improved gas distribution into the third absorber, with minimal pressure impact on the system. Addition of the vanes was estimated to cost approximately $250,000.

For a unit with a flue gas velocity of about 60 feet per second (fps), a single 90-degree elbow in flue gas ducting can result in an additional 0.5 in. w.c. pressure drop; the addition of turning vanes to the particular elbow can reduce pressure drop losses by 0.2-0.3 in. w.c. For a typical 450-MW plant, this may equate to an approximately 1-2 Btu/kWh reduction in net heat rate.

Installation of turning/straightening vanes for directing flue gas flow is applicable for any existing elbows in the gas duct. The technology is also relevant for other plant components, such as the inlet and outlet ducts of ESPs and SCR systems.

5.1.3 Shutoff Spray Level

Multiple-spray levels are commonly installed in a wet FGD system for limestone slurry delivery, typically with a dedicated slurry recirculation pump for each spray header. If a unit is operating below its permit SO_2 emission levels, it is possible to turn off one of the spray levels to save on auxiliary power necessary for pump operation. In one particular study, a 450-MW unit with three FGD modules was evaluated to investigate the possibilities of auxiliary power reduction by turning off one spray header pump on each absorber. The power savings resulted in approximately 224 kW per FGD module. The effect was estimated to be a reduction in unit heat rate of approximately 16 Btu/kWh for all three FGD modules operating. Turning off a slurry spray level would essentially remove an absorption layer, thereby creating a more streamlined path for flue gas flow across the absorber tower. This process is a relatively simple and effective means for reducing auxiliary power consumption of wet FGD systems, with no additional operating costs.

For some older units, shutting off a slurry recirculation pump may actually prove deleterious to the system due to elevated chances of plugging. For these situations, it may be possible to equip the recirculation pumps with VFDs so the pumps can operate at a lower load. In this configuration, the pumps can continue to pump slurry to their respective spray headers thereby reducing the chances of plugging problems while lowering overall system power requirements.

5.1.4 Variable-Frequency Drives

In new FGD systems, VFDs typically are used on the slurry feed and blowdown pumps of large single-vessel absorbers. This practice has become standard to accommodate changes in boiler load, particularly on units that cycle regularly. When the amount of coal combusted is decreased, the sulfur content being oxidized decreases accordingly, thus requiring less sorbent supply for SO_2 capture. Likewise, the effects of turndown will decrease the rate of gypsum formation and therefore a VFD for the blowdown pump would be appropriate. VFDs are well suited for such conditions because they allow power plants to reduce power consumption at low-load conditions and improve the precision of material stream flow rates at off-design conditions.

Generally, wet FGD slurry recirculation pumps are not equipped with VFDs, as it is more economic to simply shut off a pump at reduced load. However, as mentioned earlier, older units should consider furnishing recirculation pumps with VFDs to prevent plugging of the slurry delivery system.

Table 5-1 summarizes the FGD system modification heat rate reductions and costs.

Table 5-1. Summary of FGD System Modification Heat Rate Reductions and Costs

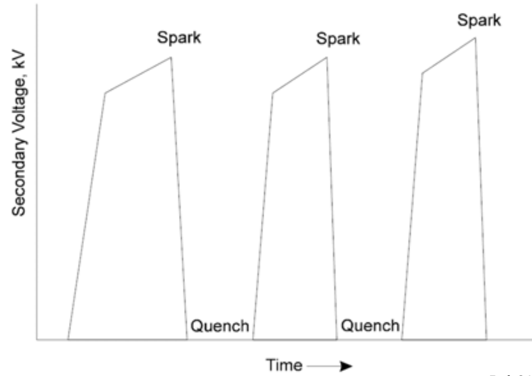
Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	0-50	0-50	0-50
Capital cost, $ million	0-1	0-3	0-5
Fixed O&M cost, $/yr	0-50,000	0-100,000	0-150,000
Variable O&M cost, $/yr	0	0	0

5.2 PARTICULATE CONTROL SYSTEM

Approximately 90% of the coal-fired electric generating units in the U.S. that operate particulate control systems use ESPs. The ESP operates by routing the particulate laden flue gas through a vessel which is divided into multiple, vertical sections. Each section is energized with an applied voltage which creates an electric field between a discharge electrode (DE) and a collection electrode (CE). The electric field ionizes the particles entrained in the flue gas and enables their capture on the CE plates. Periodically, the plates are shaken and the particles are dislodged and fall into hoppers for collection and removal.

To operate an ESP for optimal collection efficiency, the electric field strength in the inter-electrode region should be at its maximum. To create a strong electric field, an ESP's transformer/rectifier (T/R) set applies a direct current to the DE to induce a voltage until a corona discharge is produced. The corona discharge creates free electrons, which collide with the flue gas particulate matter effectively charging the particles. The charged particles are attracted by the oppositely charged collecting plates where they accumulate. The difficulty arises when the voltage is continuously increased, to maximize free ion formation, until spark-over occurs. Spark-over refers to internal sparking that occurs between the discharge electrode and the grounded, collection electrode. An example to aid the explanation of spark generation can be seen in Figure 5-1. The process of spark-over causes intermittent breakdown of the inter-electrode region electric field, which inevitably causes lack of gas ionization.

Figure 5-1. Spark Generation Profile



Source: EPA Air Pollution Training Institute (APTI)[Ref. 24]

For optimal ESP performance the applied voltage must be kept at a maximum; but remain slightly lower than the level at which spark-over occurs. In order to improve the ESP performance, utilities have increasingly made use of ESP energy management system (EMS) upgrades. The EMS enables the ESP to be optimized for varying load conditions and TR set power consumption thereby improving particle collection efficiency and overall ESP performance. The EMS also enables fine tuning of each T/R set, and if a unit is exceeding its opacity reduction expectations, it is possible to shut off one of the T/R sets to save on auxiliary power consumption. The EMS has historically been installed during an ESP rebuild or upgrade. Today, most ESPs are fitted with energy management systems.[Refs. 15, 17, 24] The utilization of an EMS can decrease the power consumed by an ESP by approximately 35% while achieving the previous particulate collection efficiency. The EMS can be installed for about $20-$40 thousand per T/R unit, depending on output voltage and current ratings.

An alternate technology that reduces the power consumption of an ESP is based upon a unique type of capacitor to address the issue of spark-over in ESPs. By filtering the output of the power supply, the technology aids the T/R set to operate with similar peak, average, and minimum voltages. This, in essence, can significantly increase the average voltage by minimizing the large, sudden drop in secondary voltage. The technology can provide a more consistent voltage supply to the respective precipitator fields, reduce the occurrence of electric field collapse and increase overall ESP performance.[Ref. 10] The technology is installed parallel to the ESP's existing T/R set for $12,000 to $15,000.

In general, upgrades and rebuilds of ESPs have enabled more efficient operation with a subsequent drop in power requirements due to improved technology. But the benefits from such upgrades are not always apparent since a utility may have to increase its particulate removal efficiency due to new environmental laws, in which case the overall power consumption may increase.

Table 5-2 summarizes the ESP modification heat rate reductions and costs.

Table 5-2. Summary of ESP Modification Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	0-5	0-5	0-5
Capital cost, $ million	0-.2	0-.5	0-.8
Fixed O&M cost, $/yr	0-25,000	0-25,000	0-25,000
Variable O&M cost, $/yr	0	0	0

5.3 SCR SYSTEM

SCR systems have been operating in the U.S. for the last 10 years. During the design stage of early SCR systems, extensive flow modeling was performed to achieve required NO_X reduction efficiency with minimum ammonia slip. The focus of these modeling efforts had been on achieving a uniform distribution of flue gas flow across the SCR catalyst. The intensive modeling resulted in highly optimized SCR systems with respect to pressure drop across the system. Aside from reducing pressure drop, a potential area for cost savings within the SCR is to use secondary air as dilution air for the ammonia vaporizer. This technique yields auxiliary power saving by avoiding the use of electric heaters. However, in some cases, hot-air bag filters may be required to eliminate the plugging of ammonia injection nozzles with fly ash in the secondary air.

Table 5-3 summarizes the SCR system modification heat rate reductions and costs.

Table 5-3. Summary of SCR System Modification Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	0-10	0-10	0-10
Capital cost, $ million	0-.5	0-1	0-2
Fixed O&M cost, $/yr	0-25,000	0-50,000	0-100,000
Variable O&M cost, $/yr	25,000	60,000	100,000

In summary, adjustments to the emissions controls equipment may yield reductions in the power plant heat rate. The estimated reductions and costs are listed in Table 5-4.

Table 5-4. Summary of Combined Environmental Controls Technology Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	0-65	0-65	0-65
Capital cost, $ million	0-1.7	0-4.5	0-8
Fixed O&M cost, $/yr	0-100,000	0-175,000	0-275,000
Variable O&M cost, $/yr	25,000	60,000	100,000

6. WATER TREATMENT SYSTEM

This section of the report discusses modifications to the water treatment system that offer potential reductions in plant heat rate:

- Boiler water treatment
- Cooling tower improvements

6.1 BOILER WATER TREATMENT

Reduction of power plant heat rate as related to cooling systems and water treatment primarily involves maintaining the proper water chemistry to reduce boiler scale and the amount of boiler water blowdown needed to control solids and impurities.

Boiler scale lowers heat transfer due to low thermal conductivity. Heat transfer may be reduced as much as 5-10% by the presence of scale. A scale approximately 1/8-inch-thick may cause an overall loss in boiler efficiency of about 2-3% in fire tube boilers, as well as in the convective sections of water-tube boilers. More important than the heat loss is that scale can cause overheating of the boiler tube metal and can result in subsequent tube failures, leading to costly repairs and boiler outages.

Iron and copper content in condensate can corrode condensate systems. This reduces heat transfer efficiency and could cause tube failure. Condensate corrosion control is required to protect process equipment, lines, tanks, as well as to maintain the condensate as a quality feedwater source. Condensate system corrosion can result in increased maintenance and equipment costs, energy loss through steam leaks, and loss of process heat transfer efficiency. To prevent condensate corrosion, volatile neutralizing amines, such as cyclohexylamine, morpholine, and diethylaminoethanol, typically are used to neutralize carbonic acid and raise the condensate pH. A blend of several amines will ensure that corrosion protection is distributed throughout the entire steam/condensate system. The use of filming amines present an alternative or additional condensate treatment process in which the compounds protect the metal components by adhering to the surface and providing a protective layer.

High-purity water provides for greater boiler cycle concentration, thus reducing water and energy losses to blowdown. Savings will be realized in reduced use of water treatment chemicals and water. High-quality water for the thermal cycle can somewhat reduce the blowdown required. By reducing the blowdown amounts, more steam is available in the thermal cycle, thereby improving overall power plant efficiency and reducing heat rate. The majority of utilities are aware of boiler chemistry and its associated issues. Most power plants already have the most advanced water treatment systems installed, leaving minimal opportunity for further improvements regarding new technology. The primary means of improvement relate to careful monitoring and maintenance of the water treatment systems for optimal water quality.

6.2 COOLING WATER TREATMENT

Cooling tower water quality not only affects O&M costs of the cooling tower, but also enables cooling tower operators to upgrade to advanced cooling tower packing. Advanced packing increases the overall thermal efficiency of the tower by increasing mass transfer efficiency, as discussed in the next subsection. However, the high-efficiency fills are more susceptible to fouling than are older style splash fill towers.

Water quality factors affecting cooling towers are those that lead to deposition on the cooling tower packing, such as suspended solids. Those leading to cooling tower surface scaling include water hardness and biological fouling. All three contaminants - deposition, scaling, and biological fouling - contribute to plugging of cooling tower fill.

Suspended solids in the cooling tower makeup water may be treated by a clarifier. The 10-15 ppm of suspended solids that is commonly the guaranteed effluent quality from a clarifier is more than sufficient for cooling tower makeup water.

The scaling tendency of water can be estimated based on the pH, alkalinity, calcium concentration, and temperature of the water using scaling indices, such as the Langelier saturation index (LSI). The LSI indicates the number of pH units the solution must be lowered in order to prevent scaling. The change in pH typically is affected by injection of an acid, such as sulfuric acid. Care must be taken to prevent over-injection of acid as that may corrode the internals of the cooling tower and circulating water heat exchange surfaces. Due to the recent increase in the cost of sulfuric acid, specialty chemical suppliers offer alternatives to straight acid injection to prevent cooling tower scaling. These chemical blends are tailored to the makeup water chemistry specific to the plant. Currently, there is no single chemical blend that would be applicable to all plants for scaling control.

Sodium hypochlorite (bleach) is the industry-standard chemical for biological fouling control. Bleach is injected either continuously at 1-2 ppm or injected at a *shock* dose of 5 ppm for 90 minutes 3 times per week. Bleach is effective in preventing biological fouling due to microscopic organisms, such as the bacteria that lead to Legionnaires' disease, and macroscopic fouling, such as Asiatic clams and zebra mussels.

It is important to note that when selecting more efficient fills, fouling degrades the effectiveness of the fill, so any increase in efficiency gained by the use of high-efficiency film fill can be forfeited through the mismanagement of cooling tower chemistry.

In general, by properly maintaining the quality of a power plant cooling water system, adequate efficiencies may be obtained for the thermal cycle. Because the proper maintenance of water quality in the cooling system is not always rigorously monitored, many plants have relied on condenser fouling as the primary means of measuring performance decreases indirectly due to water quality. Additionally, advanced cooling tower packing cannot be used unless the water quality meets a certain standard. This also renders water quality itself an indirect factor in heat rate improvement, and one that is difficult to quantify.

6.3 ADVANCED COOLING TOWER PACKING

Wet cooling towers function by utilizing the cooling effect of evaporation and to a lesser extent, the transfer of heat from the water to the ambient air through direct contact. The mass transfer from the liquid phase into the vapor phase, and therefore the decrease in temperature, due to evaporation, is strongly dependent on the contact surface area between the ambient air and the cooling water. In the past, cooling tower manufacturers increased the mass transfer area by spraying the cooling water onto planks of redwood to break the water droplets into smaller droplets and coat the surface of the planks with water. The planks were arranged such that ambient air was drawn across the planks and then up trough the cooling tower fan. This is known as a *cross-flow* cooling tower since the air primarily contacts the water in a horizontal cross flow arrangement. Cooling tower manufacturers have, within the last 20 years, altered the configuration of new cooling towers to a counter-flow design, where air and cooling water flow counter-currently through the tower, air flowing up and water flowing down. The counter-flow configuration provides an increase in the cooling tower thermal efficiency.

Both cross-flow and counter-flow cooling tower designs enable the implementation of more advanced film fill packing material. The film fill packing configuration, which provides increased heat and mass transfer between the air and water, can reduce the height (total amount) of packing required and thereby lower the fan power requirements due to a lower total air flow friction and water pumping requirements (lower vertical height). For older plant upgrades, the reduced pressure drop is probably the most significant form of heat rate reduction to be achieved from such a project due to the lower power requirements of the fans; but increasing the total amount of packing and thereby lowering the temperature of the water through the condenser can also have a significant impact on the heat rate of the unit.[Ref. 22] An optimization between fan power reductions and cooling water temperatures should be conducted to investigate the most effective use of upgrading a cooling tower fill.

Table 6-1 summarizes cooling tower heat rate reductions and costs.

Table 6-1. Summary of Cooling Tower Advanced Packing Upgrade, Heat Rate Reductions and Costs

Parameter	200 MW	500 MW	900 MW
Heat rate reduction, Btu/kWh	0-70	0-70	0-70
Capital cost, $ million	1.5	3	5
Fixed O&M cost, $/yr	0-75,000	0-125,000	0-175,000
Variable O&M cost, $/yr	0	0	0

The implementation of VFDs for cooling tower fan control can also enable power reductions if the older fans were not replaced during a packing upgrade and there is significant margin in fan capacity. The reduced pressure drop due to the new packing would enable the use of VFDs to efficiently control the speed of the fans and reduce power consumption.

The application of VFDs on cooling tower fans can also be capitalized upon during seasonal operation when ambient temperatures are significantly cooler. A cycling unit with a wet cooling tower will also benefit from VFDs being used with the cooling tower due to the lower thermal demand on the tower and subsequent reduced fan loads.

7. OTHER POTENTIAL IMPROVEMENTS

In addition to the various methods of improving plant performance discussed above, there are other areas that can provide improvements on a plant-wide basis. One such area is replacing older electric motors with new, energy-efficient motors, and another area is maintaining a rigorous maintenance program. Replacing older electric motors with more efficient motors in power plants can be a cost-effective method to reduce heat rate, and reduce downtime due to repairs. The primary problems with implementing more efficient motors are the cost of the materials and the cost of training plant personnel on the proper maintenance procedures. Generally, a cost analysis will guide a plant operator toward replacing old motors at the end of their useful lives, instead of replacing all older motors at the same time regardless of performance. All electric motors in the range of 1-200 hp sold today in the U.S. must meet high-efficiency standards as mandated by the federal government in the Energy Policy Act of 1992 (EPAct). Therefore, replacing older, failing motors will necessarily entail the inclusion of a more efficient motor. A potential exception to such requirements is a utility having a motor re-wound or rebuilt for service, which can lead to a less efficient motor than originally designed.[Ref. 1]

Potential incremental gains from 5-25% in motor efficiency can be achieved by replacing older motors with more efficient ones depending on the condition of the motors and the maintenance history of the plant. The associated possible improvement in heat rate by installing more efficient motors throughout a plant might yield a total heat rate improvement of 21 Btu/kWh. Table 7-1 summarizes potential motor efficiency heat rate reductions.

Table 7-1. Summary of Motor Efficiency Heat Rate Reductions

Parameter	Btu/kWh
Coal handling and conveying	0.7
Pulverizers	5
Ash handling	1
Condensate pumps	1.7
Miscellaneous	2.4
STG auxiliary	0.5
CW pumps	6.5
CT fans	3.4
Total motor efficiency heat rate reductions	**21.2**

The total estimated plant-wide heat rate reduction that may be realized by motor replacements is not economically feasible. It is known within the utility industry and commercial industries that replacing all old motors with more efficient ones solely for heat rate improvement is not cost-effective. The most practical method is based on replacing older motors that have failed or are expected to fail with new, more efficient motors. This is based on industry discussions that indicate a large number of plants would not apply small-scale motor upgrades at magnitudes large enough to significantly affect the heat rate.

The benefits of proper maintenance at a power plant facility can be substantial in terms of maintaining a plant's original heat rate. Modern data acquisitions systems and custom software programs on the market can enable plant personnel to both monitor and simulate performance of various processes within a plant to analyze which components are operating poorly. The savings through proper maintenance can result in several hundred Btu/kWh of heat rate reductions. The primary cost incurred for such maintenance programs are for the man-hours to take corrective action versus the initial capital expenditure to implement the data acquisition and analysis software. Since it can be difficult to quantify the hours specifically allocated to certain fields of maintenance projects, the benefits of proper maintenance can sometimes be underestimated.

8. CASE STUDIES

This section discusses selected case studies prepared by S&L as part of the overall study effort:

- 250-MW PC plant
- 850-MW PC plant with FGD and baghouse
- Axial fans versus centrifugal fans

8.1 250-MW PC PLANT

A case study was performed for a 250-MW PC power plant built and commissioned in the 1970s, in which an efficiency improvement analysis was conducted. Main steam conditions were 2360 psig/1000°F and reheat steam was 1000°F. An ESP was used for emissions control. The analysis was conducted prior to implementation of new environmental controls technology. The plant is currently operating at a heat rate of 9930 Btu/kWh; the original design heat rate was 9110 Btu/kWh.

The boiler was designed to operate with 22% excess air and 3.5% oxygen (O_2). Currently, the boiler operates very near design efficiency, based on measuring inputs for dry gas loss, moisture loss, unburned carbon loss, radiation, and other losses. The design efficiency is 88% and the current operating efficiency point is 87.4%. The most significant improvement to the boiler would be to reduce the excess O_2 concentration, which would yield a heat rate savings of 25 Btu/kWh. Implementing such a change would involve an NN system with a combustion controls module, at an estimated cost of $500,000.

The exhaust gas temperature leaving the air pre-heater is approximately 59-70°F higher than the original design value. The plant uses a Ljungström, regenerative air pre-heater. A reduction in flue gas temperatures could be obtained by installing additional air pre-heater surface area via the baskets. But additional analysis is required due to acid dew point temperatures and the resultant effects. By reducing the flue gas temperature to the design value, a subsequent reduction in heat rate of 92 Btu/kWh can be realized at a cost of $2,000,000 for a new air heater with additional surface area.

The air pre-heater leakage was measured to be approximately 8%. Although measured air pre-heater leakage values are often much lower than actual, in this case it is assumed to be 8% due to the well-maintained plant. The potential improvement in heat rate is expected to be 4 Btu/kWh by installing new seals at a cost of $300,000.

The steam turbine was evaluated for possible upgrades. Much advancement has been made in steam turbine technology since the 1970s and is certainly applicable as an upgrade. In most cases there is substantially more to be gained from larger units from an economic standpoint. In this case, a new rotor and stationary blades are suggested. The expected improvement will yield an additional 2-3 MW for the HP cylinder, 2-3 MW for the IP cylinder, and 1-2 MW for the LP cylinder. The reduction in heat rate is expected to be 255 Btu/kWh at a cost of $10,200,000 for this 250-MW unit. From an economic standpoint the industry tends to implement such steam turbine upgrades with emphasis first on the HP and then LP and IP sections, respectively.

The steam turbine was also evaluated to reduce steam leakage between the shaft and casing. The reduction in heat rate is estimated to be 15 Btu/kWh at a cost of $300,000.

The steam condenser is a once-through design and has been cleaned offline once a year. The steam condenser's materials had degraded considerably over time and a new steam condenser was recently installed to replace it. The condenser was replaced due to excessive tube plugging and condenser leaks and the high costs associated with the necessary repairs. The new condenser has stainless steel tubing and an online cleaning system. No improvements to this new system were considered.

The various electrical drive motors on the plant were taken into consideration. Most of the motors within the plant are already operating at an efficiency of approximately 93%. An expected increase to 95% by replacing all existing motors is not economically justified.

VFDs could be used on a number of large-scale motors at the plant. The use of VFDs at the plant will probably be analyzed prior to beginning back end plant upgrades.

The main boiler feed pump is steam-driven. An overhaul and upgrade to the pump could reduce the plant's heat rate by 37 Btu/kWh, at a cost of $300,000.

Feedwater heaters were considered for potential improvements. The percentage of plugged tubing was not excessive, and any possible upgrades were not considered economic given the small expected heat rate reduction and associated costs.

The plant was examined for steam leaks. A survey for visual steam leaks and a review of plant data provided no indication that a large loss was occurring.

The ESP was considered for precipitator energization management. The small reduced heat rate was not considered economic due to the costs involved.

A new DCS is currently being installed at the plant. An advanced NN could also be added, which could yield an additional reduction in heat rate of 25 Btu/kWh. The cost to implement an NN is $500,000.

Table 8-1 summarizes the modifications and the approximate costs for improvements and heat rate reduction to a 250-MW unit.

Table 8-1. Summary of 250-MW Unit Heat Rate Reductions and Costs

Parameter	Btu/kWh	Capital Cost, $
Installation of NN	25	500,000
Installation new air heaters	92	2,000,000
Steam turbine upgrade	255	10,200,000
Steam turbine seal Improvement (part of steam turbine upgrade)	15	300,000
Boiler feed pump	37	300,000
Total	**424** ~4% from the base	**13,300,000**

8.2 850-MW PC PLANT WITH FGD AND BAGHOUSE

A performance case study was conducted of an 850-MW PC power plant to evaluate upgrades for efficiency improvements and heat rate reductions. The plant incorporates an FGD system and baghouse and came on line in the late 1970s. The facility is planning future environmental controls upgrades.

The steam turbine underwent an overhaul on the HP cylinder approximately four years prior to this efficiency evaluation. The overhaul resulted in a 1.33% turbine efficiency improvement. The overhaul was primarily to reduce steam leakage and to repair the first-stage nozzles due to solid particle erosion. The upgrade cost approximately $500,000 and reduced plant heat rate by 38 Btu/kWh.

Tests to measure leakage of the primary air heater revealed that approximately 31% of the air flow was leaking. The condition of the air heater limited the amount of air leakage that could be reduced by new seals. The impact on heat rate by reducing the air leakage to 13% was estimated to be 21 Btu/kWh. The cost to install new seals was estimated to be $450,000. The secondary air heater yielded an estimated leakage of 9.5%, but this was decided to be operationally sufficient by the plant.

The boiler was analyzed for combustion efficiency and excess O_2. The plant had installed a combustion optimization system and additional hardware. Excess O_2 was reduced by 2.3%pt, yielding a reduction in heat rate of 65 Btu/kWh. The costs to install the upgrade were approximately $700,000.

The condenser was evaluated for possible performance degradation. After testing the condenser, it was concluded that the condenser was operating near the design point; and this was attributed to regular maintenance on the unit. The condenser backpressure was measured at approximately 0.12 in. Hg above the original design level. It was decided that increasing maintenance to reduce condenser pressure to design conditions would not substantially improve the performance of the steam turbine.

The LP and HP feedwater heaters were evaluated for performance. All of the heaters were very close to or were operating at the original design conditions. The worst-case heaters were operating at points at which the heat rate could be improved by approximately 0.9 Btu/kWh if returned to design conditions. A number of the heaters were performing better than design. Overall, the feedwater heaters were operating satisfactorily and maintenance operations could possibly return the heaters to their respective design points.

Table 8-2 summarizes the modifications and the approximate costs for improvements to an 850-MW unit.

Table 8-2. Summary of 850-MW Unit Heat Rate Reductions and Costs

Parameter	Btu/kWh	Capital Cost, $
HP turbine upgrade	38	500,000
Primary air heater seals	21	450,000
Combustion optimization	65	700,000
Total	**124** ~1.2% from the base	**1,650,000**

8.3 AXIAL FANS VERSUS CENTRIFUGAL FANS

A utility conducted a study to evaluate the impacts of future equipment upgrades on its current fan system at a plant. The facility is a 550-MW coal-fired unit in which an ESP is the only type of emissions control technology installed and operating. The planned upgrade included new wet FGD, SCR, and mercury removal technologies. The study entailed an analysis of various impacts from future environmental equipment on the required ID fan power and the effects of reduced load on the fan performances. A total of two new ID fans were to be used in parallel within the system.

The scenario involved installing a new wet FGD system, SCR system, and baghouse. The SCR system, and possibly the baghouse, would be installed later. The options considered were axial-flow with variable-pitch blades, and centrifugal with VFD. A centrifugal fan with VIV was considered but the differences in efficiencies precluded this from serious consideration. A fluid-coupling drive with a centrifugal fan was not considered in the study. The plant is operated primarily at base load with limited time at turndown. Therefore, plant personnel were primarily concerned with performances of the different fan options at MCR.

The study results compared the performance of the fans at 100%, 90%, and 80% MCR. Since the unit is run primarily at base load, the primary difference between the fans was a result of the design efficiency. Due to the existing centrifugal fans being limited on capacity, new axial fans were compared as complete ID replacements, while centrifugal fans were compared as booster fans. The fan efficiency of an axial fan with variable-pitch blades is inherently better than that of a centrifugal fan. At 100% MCR, the axial fan provided a 6 Btu/kWh lower heat rate than the centrifugal fan with VFD. At 90% MCR, the difference was reduced to 3 Btu/kWh, but by 80% MCR the centrifugal fan with VFD provided a 0.5 Btu/kWh lower heat rate. An economic analysis was conducted that compared the axial variable-pitch blade fan and VFD centrifugal fan. Due to the operating characteristics of the plant, the axial fan proved to be more cost-effective. It can be generalized that at roughly 85% turndown in volumetric flow, a VFD-controlled centrifugal fan will begin to show greater heat rate reductions than a VPB axial fan; as represented in this analysis.

The installed capital costs for the fan alternatives were estimated to be $3,500,000 for the axial fans and $5,600,000 for the centrifugal fans with VFDs. The costs listed in Table 8-3 do not include the auxiliary power upgrades for the wet FGD system nor the ductwork modifications.

Table 8-3. Summary of Fan Heat Rate Reductions and Costs

Parameter	Axial VPB	Centrifugal VFD
Heat Rate Reduction, Btu/kWh	6	Base
Capital cost, $ million	3.5	5.6
Fixed O&M cost, $/yr	24,000	14,000
Variable O&M cost, $/yr	0	0

9. REFERENCES

9.1 TECHNOLOGY VENDORS

Discussions were held with the following vendors during this study. Additionally, many useful case studies were obtained from the vendors listed below.

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4. Babcock Power International
5. Conco
6. General Electric
7. GE Energy/BHA Group GmbH
8. Howden
9. NeuCo
10. NWL Transformers, Inc.
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12. Riley Power Inc.
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