Asia-Pacific
Economic Cooperation

COSTS AND EFFECTIVENESS OF UPGRADING AND REFURBISHING OLDER COAL-FIRED POWER PLANTS IN DEVELOPING APEC ECONOMIES

Energy Working Group Project EWG 04/2003T

APEC Energy Working Group
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EXECUTIVE SUMMARY

This report provides information pertinent to the upgrading and refurbishment of older pulverized-coal plants in developing APEC economies. Included are:

- Descriptions of equipment operational improvements, examples for assessing and prioritizing equipment improvement options for further evaluation, and a suggested methodology for evaluating the impacts of the high priority improvements. Power plant engineers and managers will find guidance for improving the operation of their plants in this report.
- A general plant and certain equipment descriptions are provided as reference information.
- Ranking of the effectiveness and costs of a range of plant refurbishment and upgrade measures.
- Assessments of the impact of the specific upgrade and refurbishment measures on plant generating efficiency, air and waste emissions (including CO_2), plant availability, power production, and the cost of electricity generated.
- An assessment of the amount of generating capacity in different APEC economies likely to benefit from the application of plant refurbishment and upgrade measures.
- An estimate of costs and potential CO_2 emission reductions achievable through application of a range of upgrading and refurbishment options to the existing inventory of coal-fired power plants in APEC member economies.
- Identification of the major barriers to implementing successful upgrading and refurbishment projects at existing coal-fired power plants in APEC developing economies.

This report, as requested in the APEC Request for Proposal (EWG 04/2003T) to the APEC Expert Group on Clean Fossil Energy (EGCFE), furthers APEC objectives of detailing the need for and the methods of how to improve pulverized-coal plant electricity generation efficiency and reliability and costs, and the corresponding reductions of Carbon Dioxide ($CO_{2)}$ emissions.

As described in this report, upgrading and refurbishment is usually best implemented by executing the following activities:

1. Conduct a plant assessment that identifies the potential highest priority plant equipment performance improvements. Descriptions of high priority equipment design and operation relevant to performance improvements are provided.

2. Based upon the prioritization, select the equipment improvements to be analyzed in detail. The selection is based on feasibility, available capital funding, cost -benefits, and plant operations considerations

3. Complete a detailed analysis which provides estimated equipment performance improvements (including CO_2 reductions), estimated required capital costs, and operations and maintenance cost differences. This evaluation may also include operating reliability improvements that may be applicable.

Case Studies are provided for boiler air heaters, steam turbines, and condensers. An example economic spreadsheet is provided for each case study using the present worth evaluation methodology for comparing the estimated value of performance improvements to the required capital cost expenditures. Other economic evaluation methods could be used. The results of these case studies show that it is often economical to invest capital for performance improvements, which most often also brings the additional important benefit of reduced CO_2 emissions.

Two prior APEC reports provide important information on carbon dioxide (CO_2) reductions:

1. Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, November 2001, Levelton Engineering, Ltd. The information in this report pertaining to pulverized-coal plants describes the amount of electricity generated, associated CO_2 emissions, potential for plant performance improvements and emission reductions, and other relevant information for this type of generating plant.

2. Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region (Phase II) HRL Technology Pty Ltd. This report included two descriptions (Case Studies) for projects that resulted in CO_2 emission reductions that are applicable to upgrading and refurbishing pulverized-coal plants. Enabling factors for CO_2 emission reductions and two reviews were provided for targeted economies: Malaysia and Vietnam.

This report adds to the information for reducing CO_2 emissions from electricity generation provided in the prior two APEC reports. The focus for this report is to move forward from the broader perspectives provided in the prior two reports into detailed equipment assessments and economic evaluations that will assist power plant owners justify and implement specific upgrading and refurbishment projects. This report also provides a discussion relating these upgrading and refurbishment projects to the APEC region projections for CO_2 reductions presented in the Phase 1 and Phase 2 reports.

The information provided in this report includes detailed technical equipment and systems improvement descriptions, prioritization tables and case studies that show how plant equipment upgrading and refurbishment projects can be justified. Also, this report provides a person with limited pulverized-coal equipment background with brief explanation of general overall pulverized-coal plant design and basic equipment operating concepts that can have a major impact on performance. This information is not at the design level of detail, which would require volumes, but should be sufficient to facilitate communications between government, plant operations, management, plant operators and others involved in upgrading and refurbishment projects. References are provided for additional design information. The focus is on pulverized-coal plants, but portions of the information and methodology provided are applicable to other types of plants.

An additional enabling factor that will facilitate implementation of upgrading and refurbishment projects that will reduce CO_2 is suggested. This enabling factor would be a new report that analyzes the budgeting and funding needed for properly maintaining aging pulverized-coal plant units and the importance of appropriate financial and economic planning of upgrading and refurbishment projects for efficient, reliable, economic, and low-emission pulverized-coal plant operation.

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1. INTRODUCTION

1.1 Background

Generating capacity in Asia-Pacific Economic Cooperation (APEC) economies comprises approximately 2000 gigawatts (GW), of which 34% is coal fired (Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, Phase 1, pages 13 and 16). Of the coal-fired capacity, 240 GW are between 16 and 30 years old, and 160 GW are older than 30 years (Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, Phase 1, page 21, Figure 3-9). While some of the older and smaller plants are candidates for retirement, such as is occurring in China, many will continue to operate well beyond the typically referenced 40-year lifetime. Overall many of these plants are operating significantly below their design efficiency, which if corrected would provide economic improvements and emission reductions.

Experience shows that replacing existing generating plants because they are old is not usually practical because the performance of new units, although significantly improved, most often do not generate electricity at sufficiently lower costs to justify the needed large capital expenditures. New units are usually only justified by the need for additional generating capacity. Considering that more than 20% of the existing coal-fired generating capacity in APEC economies are already more than thirty years old (Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, Phase 1, page 21, Figure 3-9), this project is of vital importance to reliable, cost-effective operation of the electricity infrastructure of many APEC economies. Importantly, refurbished power plants almost always produce less carbon dioxide (CO_2) emissions (on a per kW basis) through efficiency improvement measures. Emissions of other air pollutants [Nitrogen Oxides (NO_x), particulate matter, and others) are similarly reduced. Reductions in water pollution and solid waste generation also usually occur.

Therefore, there is an urgent need to optimize the performance of these older pulverized-coal plants through cost-effective upgrading, refurbishment, and operations and maintenance improvements.

In summary, plant upgrading and refurbishment usually provides the following benefits:

- Reduced/improved fuel consumption
- Reduced/ improved emissions
- Reduced/improved operating and maintenance costs
- Higher operating reliability
- Extending the unit's operating life

1.2 Scope

Consistent with the APEC Request for Proposal (EWG 04/2003T) to the APEC Expert Group on Clean Fossil Energy (EGCFE), this report provides:

- Continued application of the results from the APEC project on CO_2 Emission Reduction Options for the Electric Power Generation Sector in APEC Economies. The two prior APEC reports are:

    - Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, November 2001, Levelton Engineering, Ltd

    - Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region (Phase II), December 2003, HRL Technology Pty Ltd

- Identified references to other reports on pulverized-coal plant performance improvements by other organizations.

Based on actual power plant project information and the experience of the authors, this report provides guidance how to:

- Rank the effectiveness and costs of a range of plant refurbishment and upgrade measures.

- Assess the impact of the specific upgrade and refurbishment measures on plant generating efficiency, air and waste emissions (including CO_2), plant availability, power production, and the cost of electricity generated.

This report also correlates information developed in this report with information developed in the preceding APEC reports by providing the following:

- An assessment of the amount of generating capacity in different APEC economies likely to benefit from the application of plant refurbishment and upgrade measures.

- An estimate of costs and potential CO_2 emission reductions achievable through application of a range of upgrading and refurbishment options to the existing inventory of coal-fired power plants in APEC member economies.

- Identification of the major barriers to implementing successful upgrading and refurbishment projects at existing coal-fired power plants in APEC developing economies.

1.3 Equipment Performance Improvements

The main focus of this report is demonstrating how to determine, on technical and economic bases, the specific refurbishment and upgrading projects that provide economic benefits and CO_2 reductions based on the existing operating condition of the pulverized-coal unit. Examples of such measures include boiler and turbine performance improvements; burner retrofits; air heater improvements; environmental control system retrofits and upgrades; fan, pulverizer, and sootblower upgrades; steam cycle improvements; instrumentation and controls upgrades.

Equipment refurbishment usually provides multiple benefits, including:

- Efficiency gains that reduce coal consumption resulting in lower fuel expenses, and other operations and maintenance cost benefits.

- Potentially reduced operational expenses by reducing maintenance costs.

- Improved plant reliability and output, thereby increasing plant revenues.

- Reduced emissions.

This report provides examples for assessment and ranking of the effectiveness and costs of a range of plant refurbishment and upgrade measures that would improve the performance and reliability of older coal-fired power plants, specifically plant generating efficiency and environmental performance.

Appropriate case studies are provided as part of this project. These case studies demonstrate a methodology for comparing the upgrading and refurbishment capital costs to the present worth of the accrued fuel and other operating and maintenance cost savings for the upgrade and refurbishment project.

Information developed for use in the case studies includes:

A. Description of the equipment refurbishment and / or improvement option(s).
B. Listing of fuel used and any fuel-related issues.
C. Development of the generating efficiency, reliability and operability improvements.
D. Approximate estimated costs of the refurbishment and / or improvements.
E. Determination of the CO_2 emissions prior to and following refurbishment.
F. Other benefits or impacts.

A significant effort was made to obtain case study data from various APEC sources for power plant upgrading and refurbishing projects. Numerous email and other contacts were made. This effort included a presentation at the APEC Workshop on Near-Term Options to Reduce CO_2 Emissions from the Electric Power Generation Sector, held in Queensland, Australia, in February 2004, and follow-up communications. The lack of response to requests for detailed data is a reoccurring problem. However, the authors utilized their extensive experience with upgrading and refurbishment projects to prepare realistic example project plant data and analyses for the Case Studies.

The evaluation and planning methodology presented in this report is an example of the type of evaluations that should be presented to power plant management and authorities for approval to proceed with detailed engineering, procurement, and other activities that lead to the implementation of the refurbishment or improvement.

2. ADDITIONAL SOURCES OF INFORMATION

This section provides description of reports and studies that pertain to the general issue of the benefits of pulverized-coal plant upgrades and refurbishments and for additional technical equipment on equipment.

2.1 CO_2 Emission Reduction Options in APEC Economies

The following two prior APEC reports provide important information on carbon dioxide (CO_2) reductions.

- Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, November 2001, Levelton Engineering, Ltd.

  The objective of this study was to assess the current status of the approaches taken by member APEC economies to increase CO_2 reduction in the APEC region, and to analyze the options available to reduce CO_2 emissions growth in the future. The report provided a description of the electricity generation sector with individual country breakdown, by fuel and technology used, as a basis for calculating baseline emissions of CO_2 and the potential for reductions. It described options for obtaining CO_2 emission reductions, ranging from fuel switching and plant improvements to full-scale repowering. These options were illustrated by a set of emission reduction scenarios that might be achieved by their application, highlighting some of the most effective approaches under different circumstances. Finally, it contained a comprehensive review of health impacts of pollutants from electricity generation technologies and means of reducing these impacts.

  In addition, this report's reference section provides a list of over 120 technical papers, reports and other reference that is an excellent source for additional applicable information.

- Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region (Phase II), December 2003, HRL Technology Pty Ltd.

  This follow-up study built upon the CO_2 phase I results and examined the policies needed to support and accelerate the implementation in developing economies of the short and medium term CO_2 reduction measures that were found to be the most promising in the phase I study. The report presented a number of detailed case studies of specific CO_2 reduction options already implemented, or considered for implementation, in the fossil electricity generation sectors of several APEC economies. It assessed and prioritized the various CO_2 reduction options identified in Phase I for a few select economies over the short-to-medium term, using a number of case studies in different economies. It assessed the more attractive options in detail for a few select economies and considered future generating facilities as well as existing facilities. The study described existing obstacles and barriers to the adoption of cleaner, more efficient fossil fuel-based generating technologies. It described general governmental policies and initiatives required to support and promote more efficient technologies, highlighting successful policies and initiatives that could be adopted in other APEC economies. Finally, it developed action plans for two developing APEC economies with high CO_2 reduction potential, to hasten adoption of fossil fuel-based power generating technologies that will yield lower CO_2 emissions over the short-to-medium term.

This report included two descriptions (Case Studies) for projects that resulted in CO_2 emission reductions that are applicable to upgrading and refurbishing pulverized-coal plants. Enabling factors for CO_2 emission reductions and two reviews were provided for targeted economies: Malaysia and Vietnam.

- Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region (Phase III), APEC Workshop on Near-Term Options to Reduce CO_2 Emissions from the Electric Power Generation Sector, Queensland, Australia, February 2004.

  Phase III of the APEC project drew together the results of the earlier phases by organizing and holding a workshop on Options to Reduce CO_2 Emissions from the Electric Power Generation Sector in APEC Economies, where both government and industry participants from all APEC member economies addressed the latest issues and experiences in the reduction of CO_2 emissions from fossil fuel power generation. It focused on issues that can affect coal as a future energy source in developing APEC member economies, and on technologies and methods that can achieve real reductions in CO_2 emissions growth in the short- and medium-term. While coal was the central focus, other fossil fuels were included in the workshop. Participation included experts in the field, senior government officials, executives from the power industry of both developed and developing economies, technology suppliers, and financial sector representatives. The APEC Workshop's 32 expert speakers and panelists provided a substantial body of new information on efficiency improvement for existing plants, near- and medium-term options for new generation, emission strategies (including voluntary trading), and fuel and power plant strategies, including biomass cofiring.

Please refer to Appendix 1 to this report for references to the information from these two reports that is applicable to this report.

2.2 Other Applicable Reports

Other reports on pulverized-coal plant performance improvements by other organizations that were identified that are referenced in this report are listed below:

- Improving efficiencies of coal-fired power plants in developing countries, International Energy Agency's (IEA) Clean Coal Center, ISBN 92-9029-385-3.

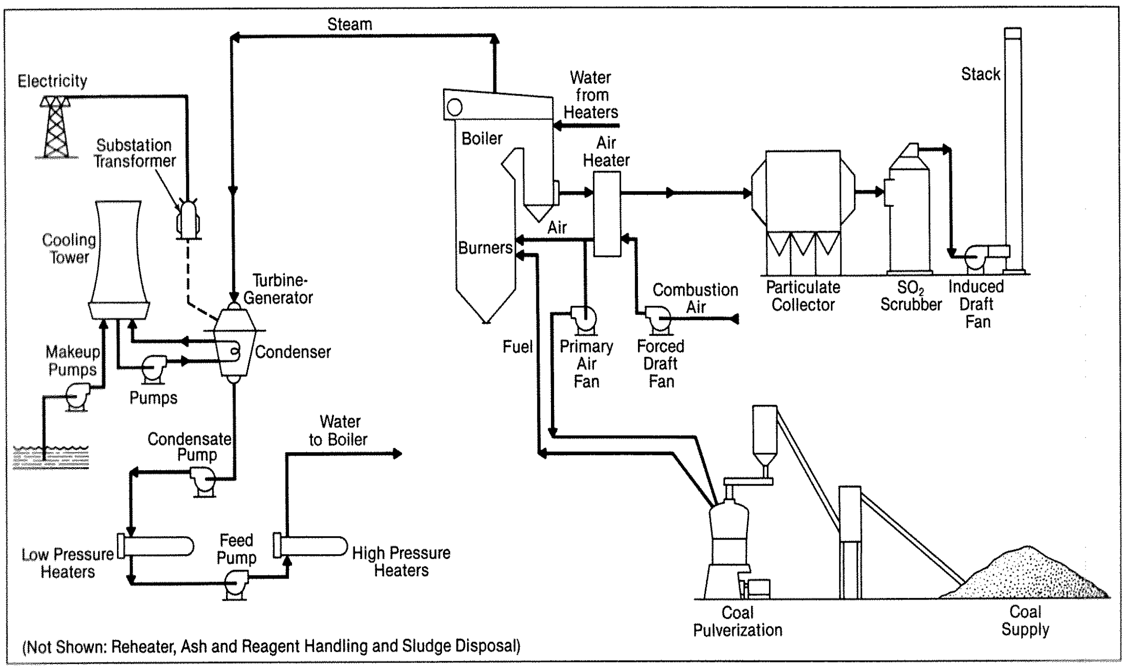
- Integrating Consultancy – Efficiency Standards for Power Generation for the Australian Greenhouse Office (January 2000) prepared by Sinclair, Knight Merz, Unclassified Version (from the Australian Greenhouse Office web site).

3. PULVERIZED-COAL PLANT OVERVIEW

It is important that communications between engineers, managers, government personnel, the general public and others are based on a reasonably accurate understanding of the plant equipment so that the need for and the means to improve plant operations can be properly considered. This section provides a brief and general overview of pulverized-coal plant design to facilitate use of this report by readers who can benefit from this background information.

Major components of a typical plant include a pulverized coal-fired boiler, steam turbine generator, condenser and other equipment shown in Figure 1. This is a current-day typical pulverized-coal plant design, but there can be many differences for a specific plant.

Figure 1: Typical Pulverized Coal-Fired Plan



Reference: Babcock & Wilcox, Steam, Page 1-4

Coal fuel from the mine is transported to the plant area by ships, barges, trains, trucks or conveyors. It is unloaded at the plant to the coal supply storage area. Conveyor belts bring the coal to silos that are located adjacent to the boiler above the pulverizers. Coal pulverizers produce powder consistency, dry coal, which is blown through pipes to the burners. Coal combustion takes place within the boiler furnace. Water is heated in tubes that form the boiler walls. High-pressure and -temperature steam from the boiler flows through pipes to the turbine. Steam from the high-pressure turbine section is often reheated in the boiler reheater before flowing to the condenser for improved cycle efficiency (not shown). Steam continues to flow through the turbine converting steam pressure and temperature energy to mechanical energy that turns the generator resulting in electricity generation.

When the steam reaches the lowest practical pressure (significantly below atmospheric pressure, which results in higher plant efficiency), it leaves the turbine and enters the condenser. The condenser is a steel enclosure that has thousands of small tubes for cooling water to condense the steam. The cooling water is pumped from the ocean, rivers, lakes or cooling towers. Water from a river or other source supplies the cooling tower system with makeup water to replace cooling tower evaporation. In some plants, an air-cooled instead of a water-cooled condenser is used. Additionally, water is treated in a demineralizer system to replace some of the water and steam that is lost in the boiler and because it is usually necessary to drain (blow down) a portion of the boiler water to maintain the required high quality water chemistry needed for the boiler. There are many other requirements for water within the plant.

Feedwater heaters improve the cycle's thermal efficiency by heating the water from the condenser before it enters the boiler with steam from the turbine. This often-used power plant design is called the Rankine Cycle.

Flue gas from the boiler furnace usually flows through an air heater, which improves the plant efficiency by heating the incoming combustion air. The type of boiler flue gas emission cleanup equipment varies widely. Figure 1 shows a particulate collector and a SO_2 scrubber for flue gas desulfurization. In the FGD vessel, lime or limestone captures SO_2 by a chemical reaction that, described in simple terms, results in mainly calcium sulfate ($CaSO_4$). However, many older coal plants and some newer plants are not required have scrubbers based on local air pollution regulations. Induced draft (ID) fan(s) move the boiler flue gas from the boiler furnace through the air heater and emission control equipment to the chimney.

Newer and also the larger existing coal plants often have more equipment and increased equipment pollutant removal performance for meeting stringent emission control equipment regulations. Boilers also may have new burners for low NOx emission. In addition, the boiler flue gas may flow through a selective catalytic reduction (SCR) unit that is located between the boiler and air heater for additional NO_x reduction. In some cases, NOx is reduced using a selective non-catalytic reduction (SNCR) system, or other cost-effective technology.

Forced-draft fans provide most of the air needed for combustion. Flow from the primary air fans carries the pulverized coal to the burners and also provides the needed additional combustion air.

Ash from the bottom of the boiler and flue gas particulate collector is accumulated in separate hoppers and carried by truck or by pipeline to the storage bins or landfill areas. Particulate collector ash is often utilized in producing cement, or in other ways.

In addition to the main plant equipment and systems described above, a variety of other important systems, equipment and plant facilities are required for a coal-fired power station. The following list is typical for many plants:

- Compressors supply air for valve and other pneumatic actuators and for maintenance use.

- Auxiliary boilers provide steam for heating the plant when the main boilers are not operating and for starting the main boiler and turbine units.
- Vacuum pumps remove air that leaks into the condenser and non-condensable gasses that enter the condenser from the power cycle piping and equipment.
- Chemical feed equipment is provided for the boiler water to maintain pH, oxygen content, and other parameters within the required ranges.
- Equipment lubricating oil systems are provided on the main turbine-generator, boiler feed pumps and motors, coal pulverizers, and other equipment. Turbine oil lubricating oil storage tanks and filters are provided for the turbine-generator for use during maintenance.
- Fire protection systems and pumps are provided for the major lubricating oil reservoirs and piping on the steam turbine-generators, main transformers, coal handling, and other applicable areas. A diesel-engine-driven fire pump is provided as a backup to the electric-motor-driven pumps.
- Service water supplied from a river or other source is needed for washing the coal handling and other plant areas and for supplying other miscellaneous maintenance uses.
- Foundations, piping, and supports are needed for all of the equipment.
- Fuel oil (No. 2 grade) or natural gas is required to warm the main boilers and ignite the coal fuel during startup, and for the auxiliary boilers.

Components of the major electrical and controls equipment, which is typical for these types of plants, are listed below:

- The substation step-up transformer (shown in Figure 1) raises the generator voltage for the transmission lines leaving the plant.
- Station service transformers for plant equipment.
- Switchgear and motor control centers to control electrical power for motors, electrical systems, and equipment.
- Distributed control system (DCS) for centralized operator control from the main control room.
- Plant instrumentation to provide data to the DCS.
- Local or separate programmable computer systems for water treatment, turbine-generator, coal handling, ash handling, and other equipment.
- Continuous emissions monitoring system (CEMS) for monitoring emissions from the two chimneys.

4. EQUIPMENT REFURBISHMENT AND UPGRADING OPTIONS

The prior section provided a brief overview of a typical pulverized-coal plant design. In this section, refurbishment and upgrading options are described. Although there are many other upgrading and refurbishment options, most often the following options are considered to be applicable to existing pulverized-coal units, and these options provide examples for consideration of other options. Also, it is important to note that correcting the operating deficiencies associated with these equipment usually results in the largest improvement of unit efficiency and emissions. This is demonstrated by the prior two referenced APEC reports. Other equipment improvement options should be considered based on the type, current performance, and condition of equipment in the specific plant.

Section 3 provides a brief description of pulverized-coal plants, which if needed, can suffice as an introduction to the equipment that is discussed in this and the following two sections.

4.1 Air Heaters

Air heaters heat combustion air and cool boiler exit flue gas. Boiler efficiency is improved and the hot air needed for drying coal and obtaining proper combustion is provided to the pulverizers and burners. The two types of air heaters used most often are the regenerative and tubular air heaters.

Air heater operating deficiencies include excessive leakage of combustion air into the boiler exit flue gas flow, low air temperatures to the pulverizers and burners, excessive air and flue gas pressure loss. These problems cause lower boiler efficiency, reduced gas and air flows, reduced air temperatures, and reduced coal input that can limit boiler output. Pollutant emissions often increase because lower boiler efficiency requires increased coal consumption. Air leakage results in increased flue gas flows that consequently reduce precipitator collection efficiency.

Performance improvement depends on the design and the current performance of the existing air heater. Flue gas leaving some operating air heaters has exceeded the design value by 5 ºC to 20 ºC and air leakage to into the flue gas flow may reach 40%. As a result of these conditions, boiler efficiencies can decrease in the range of 0.2% to 1.5%. These deficiencies can be corrected by air heater improved surface cleaning, air to gas path seal improvements, and other upgrading and refurbishment.

4.2 Pulverizers

Pulverizers dry and process coal to a fine powder that is required in the burners. Improved and refurbished pulverizers often reduce unburned carbon, which is wasted fuel. Fly ash carbon content in the range from 1% to over 30% has been encountered. A 30% fly ash carbon content will cause a loss of boiler efficiency in the range of 0.2% to 0.5%.

Pulverizer upgrading and refurbishment can also reduce the amount of ash slag (iron, silica, calcium and other coal ash constituents) that collects on furnace walls, superheaters, and reheaters, thereby improving heat transfer and boiler efficiency. These ash accumulations may also cause overheating and corrosion of boiler tubes, causing failures that require boiler shutdown for repairs.

4.3 Burners

Burners mix coal and primary air with secondary air for injection into the furnace. With improved burners and instrumentation more complete combustion of the coal with lower NOx emissions is possible. In addition, with new burners and instrumentation, operators can adjust air and coal flow for complete combustion and lower unburned carbon, and reduce water wall slagging and superheater/reheater slagging and fouling. These improvements result in better heat transfer within the furnace and improved boiler efficiency. Improved coal feeders and pulverizers may also be needed to achieve the benefits of improved boiler efficiency. As noted above for improved pulverizers, the impact on boiler efficiency can be significant.

4.4 Burner Furnace Sootblowing Upgrades

Improved or additional sootblowers increase furnace, superheater, and reheater heat absorption leading to increased boiler efficiency, reduced coal consumption, and lower emissions by maintaining these tube surfaces reasonable clear of ash accumulations that reduce heat transfer.

4.5 Steam Turbines

Steam turbines convert the boiler steam energy into rotating energy for turning the generator.

Improving steam turbine performance by refurbishing will result in significant performance improvements. Refurbishments include removing deposits that cause a reduction in blade aerodynamic performance, repairing or replacing the first stage turbine blades that have been damaged by boiler tube scale, replacing or adjusting blade and shaft seals, and other activities. In addition, major performance improvements can be implemented on many turbines with newer, more efficient turbine blades and other components. These improvements are possible because current turbine designs perform more efficiently than the designs that were available ten to twenty years ago.

4.6 Condensers

Condensers receive steam from the steam turbines where cooling water flowing through tubes cools and condenses the steam. Condensing lowers steam turbine exhaust pressure and increases turbine efficiency. Also, condensing the steam allows pumping and recycling the high quality water to the boiler.

Scaling on the water-side of the condenser tubes decreases the heat transfer coefficient and higher condenser pressures result. Increased condenser pressure will significantly reduce steam turbine output and efficiency. Air leakage into the condenser can also increase condenser pressure and will lower the quality of the recycled water.

4.7 Forced Draft, Primary Air, and Induced Draft Fans

Forced draft (FD) fans supply air to the burners and in some systems to the pulverizers. With a pressurized furnace, the forced draft fans provide sufficient pressure for the flue gas flow through the furnace, air heater and flue gas cleanup equipment to the chimney. Some boilers have primary air fans that supply air to the pulverizers, whereas some boilers have blowers or exhausters on each pulverizer. Induced draft (ID) fans move flue gas from the furnace through the air heaters and flue gas cleanup equipment to the chimney.

Increased fan flow and pressure are required for various reasons:

- Changes in the coal quality and moisture.
- Air heater and other equipment pressure losses have increased.
- Air pollution control or burner modifications have increased air and flue gas pressure losses.
- The original design pressures and flows for the fans were not adequate for the current actual operating situation.

Unit output reductions from fan performance deficiencies have been encountered that have reduced unit output in the range of 2% to 8%.

4.8 Control and Instrumentation

Control and instrumentation improvements can reduce total fuel consumption due to quicker and more coordinated startups, and provide better control of fuel and air during normal operation. The main impacts of improved controls are improved operating efficiency due to better control of excess air and steam pressure and temperature, as well as faster load changes in response to the generating system requirements. In addition, boiler and turbine stresses are reduced because startup and load changing is coordinated to reduce temperature and pressure variations. This often provides higher unit availability because of the decrease in thermal stresses and inadvertent unit trips during generating system transients, which, in turn, lead to turbine, boiler and other equipment failures.

5. EQUIPMENT REFURBISHMENT AND UPGRADING DESCRIPTIONS

This section describes main causes and effects of pulverized-coal plant equipment performance degradation. The improvements and refurbishments that are most often implemented to correct performance degradation are briefly described for each of the major causes. References are provided for additional explanations of equipment design and operation, as well as to identify corrective improvement and refurbishment measures.

5.1 Air Heaters

5.1.1 Introduction

Some boiler suppliers use the term "air heater" and others use the term "air preheater". This report will use the term "air heater". Air heaters are recuperative type heat exchangers.

Air heaters are used in pulverized-coal plants to:

- Improve plant efficiency by reducing the flue gas temperature leaving the boiler and heating the combustion air entering the boiler.
- Provide heated air to the burners for improved combustion.
- Provide hot air to the pulverizers to dry moist coal for proper combustion.

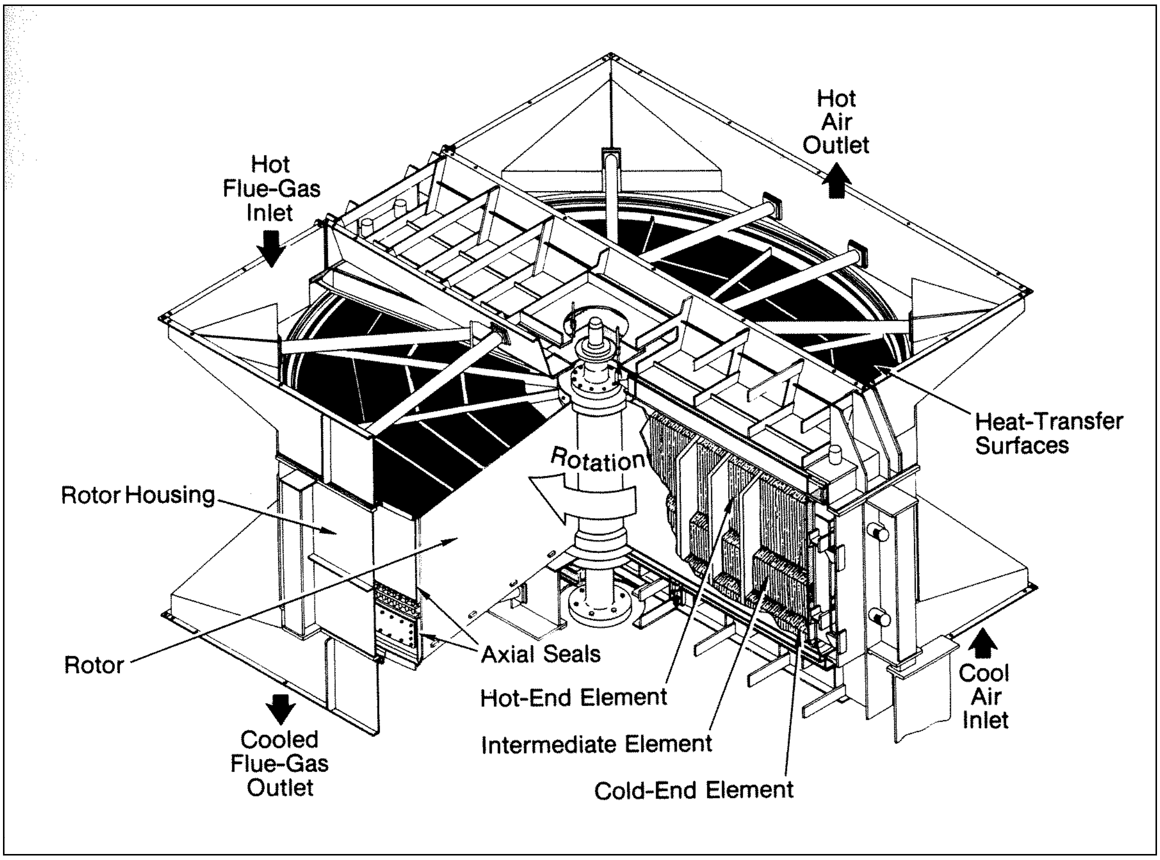
Air heaters usually provide reliable operation, but often require maintenance and repairs when the unit is shutdown for periodic major overhauls. This maintenance includes water washing to clean the surfaces of ash buildup that is not removed by the sootblowers or other cleaning systems used while the unit is in operation, maintaining these sootblowers and other systems, adjusting seals (if applicable), and checking the other air heater components.

Additional air heater design and operational information can be obtained from Babcock & Wilcox, <u>Steam</u>, 1992, page 19-6; Combustion Engineering, <u>Combustion Fossil Power</u>, 1991, page 14-23.

5.1.2 Regenerative Type Air Heaters

The most often used air heater design is the regenerative type. This design includes thin metal plate heat exchange surfaces mounted in frames (often called baskets) and supported in a large rotor (rotating wheel) configuration. Flue gas warms the heat exchange metal surface and heats the air when these surfaces rotate into the air stream. Seals minimize the flow of higher-pressure combustion air into the flue gas stream. The figure below shows this design:

Figure 2: Regenerative Type Air Heater



Reference: Combustion Engineering, Power, page 14-29.

Major causes of air heater performance degradation and refurbishment measures are outlined below:

Table 1: Air Heater Performance Degradation and Refurbishment Measures

Degradation and Impact	Cause	Improvement and/or Refurbishment
Corrosion of heat exchange surfaces (especially the cold element surfaces) results in less heat transferred from the flue gas flow to the airflow.	1. Moisture, sulfur and other corrosive coal constituents. Fly ash entrained in the flue gas entering the air heater erodes the heat exchange element oxide coating, which results in continuous corrosion of the element surface.	1. Replacement of the heat transfer surfaces with the original materials, with more corrosive/erosive resistant materials or the use of coatings.
	2. Flue gas sulfur oxides will condense on air heater surfaces causing corrosion if the flue gas temperature leaving the air heater is too low for the coal being fired.	2. Heating combustion air upstream of the air heater with steam from the turbine or other source is usually provided to have higher air temperatures for better combustion of the coal. In addition, increased air temperature results in an increase in the air heater exit flue gas temperature, which reduces condensation of sulfur oxides that causes corrosion of the air heater heat exchange surfaces. Bypassing air around the air heater through a duct with a control damper will raise the air heater exit gas temperature and reduce corrosion. The bypass option is feasible when there is adequate combustion air and pulverizer supply air temperature.
Plugging of air/gas heat transfer passages which causes increased air and flue gas pressure loss that can increase to the point of causing air and/or gas flow reductions that require reduction in plant output.	1. Soot blowing and/or water washing is ineffective.	1. Install new sootblowers, improve air or steam supply to the sootblowers and/or add water washing for use during maintenance shutdowns.
	2. Excessive corrosion causes scale to block the passages between the thin metal heat exchanger surfaces.	2. Install new surfaces and investigate improved materials or coatings that are corrosion and erosion resistant. Also, there are newer heat exchange surface configurations that are more easily cleaned by the sootblowers during normal operation.

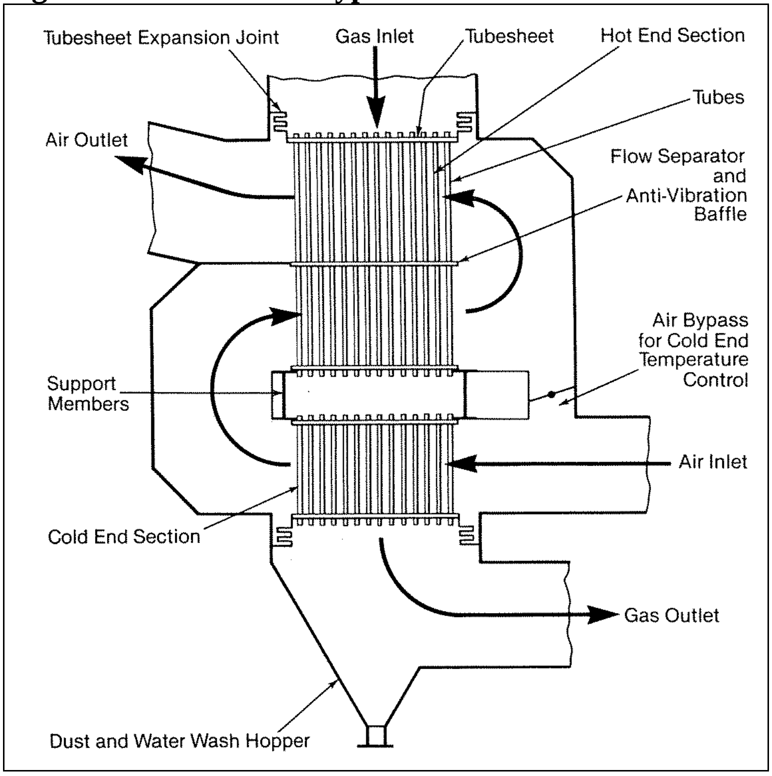
Degradation and Impact	Cause	Improvement and/or Refurbishment
	3. Inadequate ID fan capacity	3. Increase fan capacity by adding fan blade extension tips, new fan rotors, and larger motors. Also, reduction in pressure losses will increase air and flue gas flow; for example, improved air heater surfaces, improved air and duct flow pressure losses (for example, adding turning vanes), reduced burner pressure losses.
	4. Inadequate FD fan capacity	4. Increase fan capacity by adding fan blade extension tips, new fan rotors, and larger motors. Also, reduction in pressure losses will increase air and flue gas flow; for example, improved air heater surfaces, improved air and duct flow pressure losses (for example, adding turning vanes), reduced burner pressure losses.
Air to Gas Side Leakage – Pulverized-coal boilers have FD fans supply air to the burners and ID fans removing flue gas from the furnace. Within the air heater, air is at a positive pressure and flue gas is at a negative pressure. Leakage occurs across the seals, which causes a reduction of air supply to the burners and an increase in ID fan flow. If leakage is excessive insufficient combustion air or excessive gas flow (with the additional air leakage) may cause a reduction in boiler output because required fan flow is often beyond the maximum design capability.	There are three major seal leakage paths with this type of heat exchanger. 1. Radial seals are located across the heat exchanger surfaces from the air heater rotor shaft to the outside diameter of the air heater rotor. These seals are located on both sides of the rotor. 2. Circumferential seals are located around the outer rotor diameter on both sides of the rotor. 3. Post seals prevent leakage along the rotor shaft.	Seal adjustment and replacement is a routine maintenance and repair activity. Also, the installation of newer seal designs is an option. Seal repairs and adjustments are very important to prevent unit output reductions because of fan limitations. ID fan capacity deficiencies often are caused by this problem.

Please see the references listed at the end of this section for descriptions of the equipment design, operation and performance.

5.1.3 Tubular Type

The tubular type air heater is the next most often used air heater after the regenerative type. This type is a simple arrangement of tubes inside a casing. Boiler flue gas flow is usually through the inside of the tubes the airflow is over the outside tube surface. The opposite arrangement is also used with air on the inside of the tubes and gas on the outside of the tubes. The figure below shows the arrangement for this type of air heater:

Figure 3: Vertical Type Tubular Air Heater



Reference: Babcock & Wilcox, Steam, Page 12-6

Major causes of performance degradation and many of the required improvement and refurbishment measures are the same for tubular heaters as for the regenerative type heaters described in the preceding section. However, where applicable based on design differences, the implementation of the improvements and refurbishment measures are different based on the tubular instead of the thin heat transfer metal heat exchange surface design.

Additionally, tubular type heaters may have a flue gas surface cleaning system that provides for small metal balls to drop through the tubes knocking off ash accumulations. The ash and the cleaning balls are collected in a hopper below the air heater surfaces. Ash is separated and conveyed to the disposal system and the metal balls are recycled to the top of the air heater for another pass through the tubes. This system works satisfactorily with some types of coal, but not with others. Replacement of this system with an air or steam sootblowing system has achieved improved air heater performance with certain types of coal.

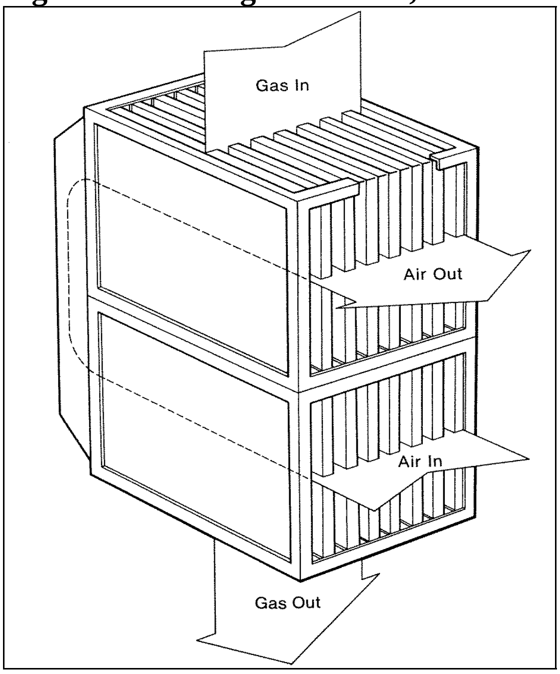
Changing the size of the tubing is another option. Larger tubes will be easier to clean, which may provide the needed improvement. However, larger tubes, even though being cleaner, may result in a reduction in performance. Smaller tubes may provide space for additional tubes and improved performance, but smaller tubes are more susceptible to ash buildup. An evaluation of changing tube size should include the type of coal(s) that are used and the impact on the tubular air heater surface.

Air to flue gas seal leakage does not occur because this type of heater does not have a rotor. However, leakage does occur because of corroded tubes and where the tubes connect to the inlet and outlet tube sheets. Finding leakage paths is difficult because these leakage areas are not easily seen. Testing for high oxygen zones in the gas path can assist in locating the leakage areas.

5.1.4 Other Types of Air Heaters

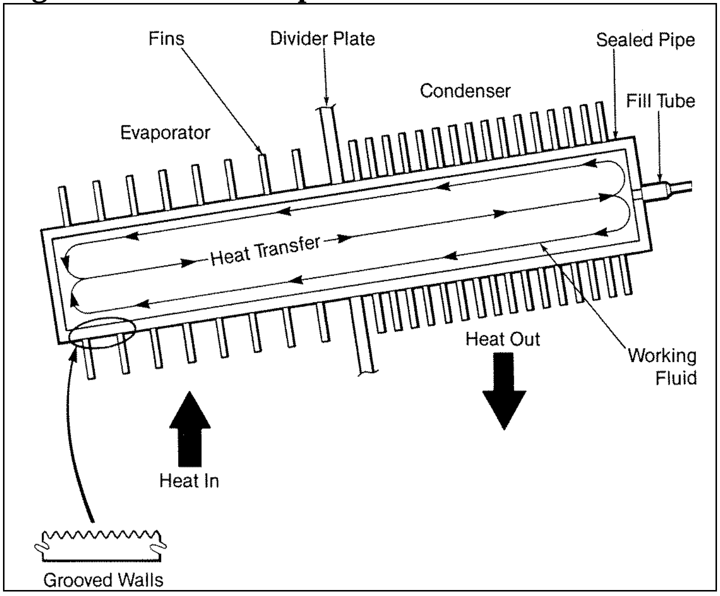
The plate and heat pipe type heat exchangers may have been used in some pulverized-coal plants. Figures showing these types of heaters are provided below:

Figure 4: Single Gas Pass, Two Air Pass Plate Air Heater



Reference: Babcock & Wilcox, Steam, Page 19-8

Figure 5: Heat Pipe Schematic



Reference: Babcock & Wilcox, Steam, Page 19-8

The heat pipe tube configuration is mounted in a casing similar to the tubular air heater casing.

Operational improvements described for the regenerative and tubular air heaters may have some application to these heaters. However, the analysis of the operating problem and the specific design is needed to properly identify the potential improvement and refurbishment measures.

5.1.5 Air Heater References

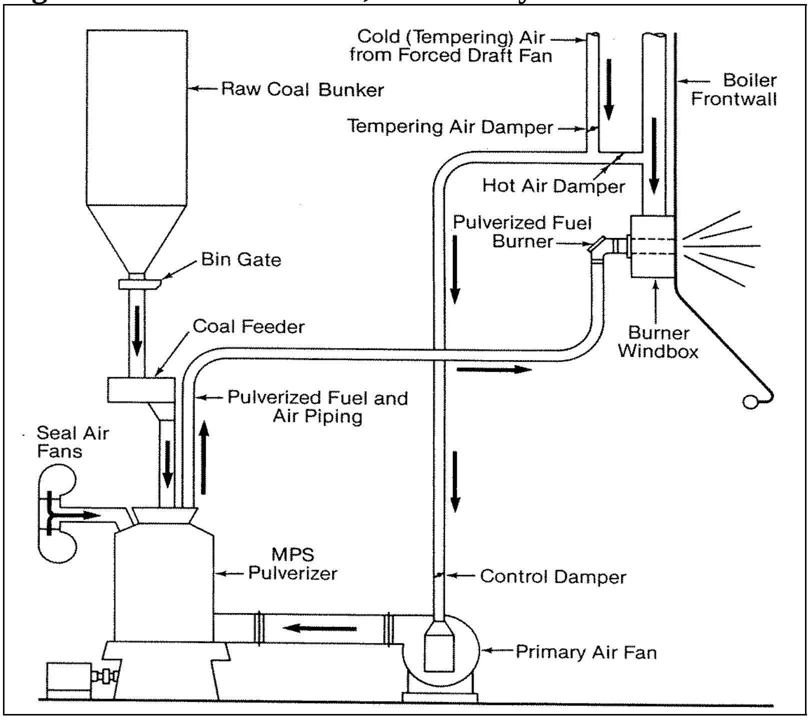
Babcock and Wilcox, Steam, 1992, page 19-9.
Combustion Fossil Power, Combustion Engineering, 1991, page 14-28
Power-Gen Europe 1996, Modernisation of Rotating Matrix Regenerative Air Preheaters

5.2 Pulverizers

5.2.1 Introduction

Pulverizers provide small particles of dry coal to the boiler burners. The figure below shows a typical pulverizer and burner configuration for supplying combustion air (secondary air) to the burners and air for drying the coal in the pulverizers and conveying the coal to the burners (primary air).

Figure 6: Direct Fired, Hot Fan System for Pulverized Coal

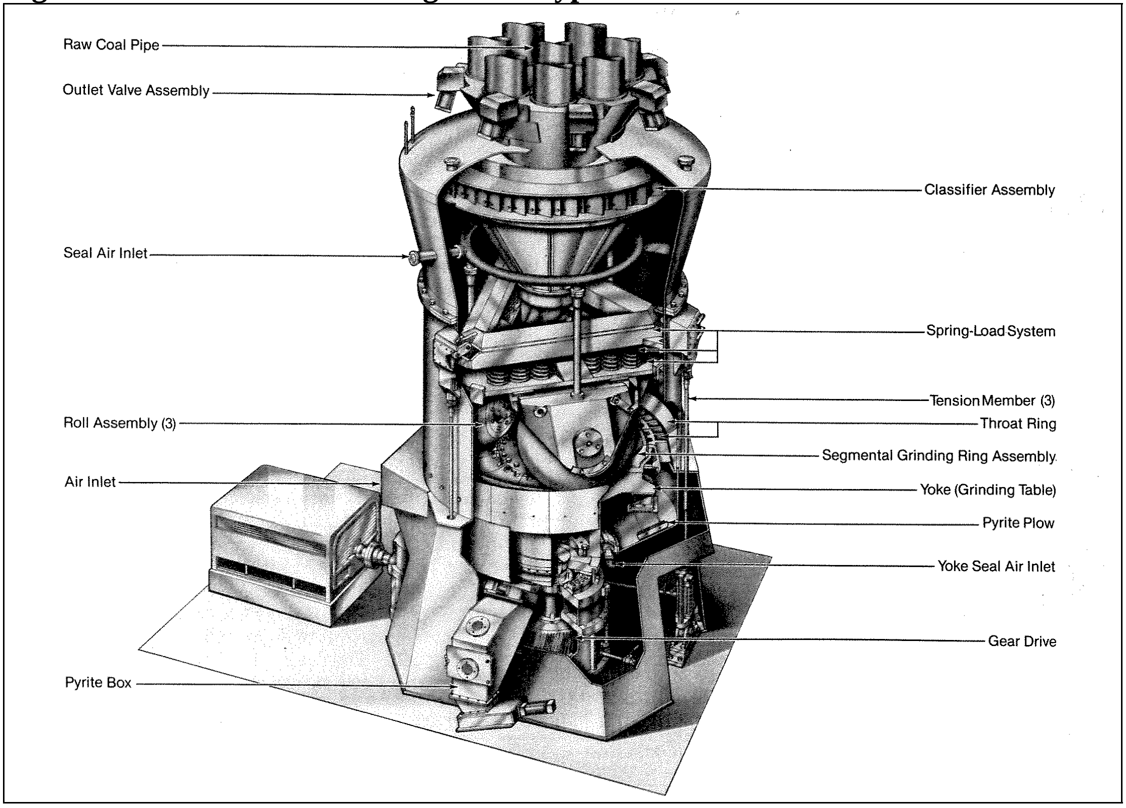


Reference: Babcock & Wilcox, Steam, Page 12-6

Improvements to pulverizers (often called mills) can reduce unburned carbon and the amount of slag that collects on furnace wall tubes, superheaters, and reheaters. The slag reduces heat transfer and overall boiler efficiency. As mentioned above, the slag accumulations can also result in overheating of boiler tubes causing corrosion and eventual failure of boiler tubes and resulting plant outages. It is important that the coal be pulverized to particles that are fine enough to prevent the slagging on furnace walls.

Ring-roll (also known as “roll and race type”) and ball-race (also known as “ball and roller type”) mills comprise the largest number of pulverizers used for coal grinding in central station power plants. They rotate at medium speed [75 to 225 revolutions per minute (rpm)] and primarily crush the coal along with some impacting of the coal particles to reduce the size of the coal. The grinding of the coal takes place between two surfaces with one surface rolling over the other. The rolling element may be a ball or roll while the pulverizer component that it rolls over is either a race or a ring. There also are ball-tube, impact, and attrition pulverizers. The type of pulverizer depends on the coal characteristics, the size of the boiler and the manufacturer’s capabilities. (Combustion Engineering, Combustion Fossil Power, 1991: page 11-23). The figure below is for a roll and rotating table type pulverizer.

Figure 7: Roll and Rotating Table Type Pulverizer



Reference: Babcock & Wilcox, Steam, page 12-1

It is normal when designing a power plant to provide one or two standby pulverizers to permit on-line maintenance of a pulverizer while the unit is operating at full boiler load. If, for example, there are five pulverizers installed, four pulverizers will be capable of feeding the boiler at full-load grinding the worst fuel that the unit must handle. In the event of pulverizer performance degradation, poorer grades of coal, or the need for greater coal fineness to the burners, this spare pulverizer can be used during normal full load operation.

If the pulverizers, burners, and furnace are properly designed, the boiler can maintain an efficiency loss due to unburned carbon of less than 0.4% to 1.0%. However, if the pulverizers are not designed properly for the coal being crushed and the percentage of particles passing a 200-mesh (i.e., 74-micron) screen is higher than 80%, there will be excessive suspension burning which can result in high carbon loss and other problems.

Coal grindability and moisture content has a large affect on pulverizer performance. The grindability index (Hardgrove Grindability Indices, HGI) was developed to measure the ease of pulverization. Surface moisture adversely affects pulverizer output and fineness as well as the combustion process. The total moisture content is comprised of equilibrium moisture and surface, or free, moisture. During heavy rains, pulverizer capacity can decrease due to very wet coal. Sufficient in-pulverizer drying requires adequate hot air from the air heater. Often more pulverizer capacity results in a relatively dry coal. The hot air source for the pulverizer system is usually provided by recuperative air heater using combustion gas as the heat source. This source of hot air for large boiler installations usually provides sufficient hot air for drying the coal as required.

Major causes of pulverizer performance degradation and refurbishment measures are outlined below:

Table 2: Pulverizer Performance Degradation and Refurbishment Measures

Degradation and Impact	Cause	Improvement and/or Refurbishment
Excessive wear of the rolls and grinding rings causing poor pulverization of the coal and increased slagging tendencies in the boiler.	Highly abrasive coals depending on the type and quantity of impurities in the coal, Excessive operating hours of the mill, High pulverizer loading as a percent of maximum capacity.	Apply a hard-surface weld overlay that is at least ½ inch thick. For used rolls, overlays up to 2-1/4 inch thick can be applied to return the roll to its original size. Hard surface materials include Hi-Chrome, Ni-Hard, 3.5% Cr Steel, 20% Cr white cast iron, and others depending on the coal's abrasiveness.
Excessive wear of other component parts causing poor pulverization of the coal and increased slagging tendencies in the boiler.	Highly abrasive coals depending on the type and quantity of impurities in the coal, Excessive operating hours of the mill, High pulverizer loading as a percent of maximum capacity.	Apply a hard-surface weld overlay or replace the component with the original material including abrasion resistant steel plate, high-nickel castings, or ceramic materials.
Pulverizer not meeting capacity requirements causing loss of plant output.	Insufficient hot air to dry the surface moisture off the coal.	Increase hot air flow to the pulverizer or add supplemental heating to increase total hot air flow.

5.3 Pulverized-Coal Burners

Burners and their associated controls are very important in assuring efficient operation of the boiler. With improved burners and instrumentation, more complete combustion of the coal with lower emissions is possible. In addition, complete combustion reduces water wall slagging and superheater/reheater slagging and fouling. These improvements result in better heat transfer within the furnace and improved boiler efficiency.

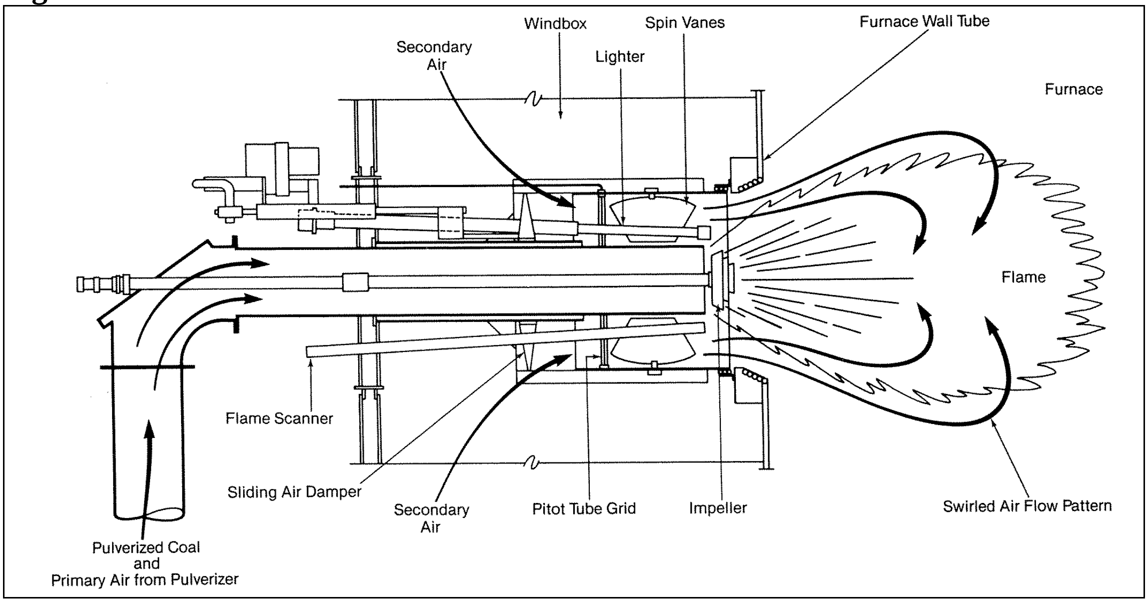
The primary purpose of a burner in the furnace is to mix and direct the flow of coal and air to ensure rapid ignition and complete combustion. In burners firing pulverized coal, a part (15% to 25%) of the air, called the primary air, is initially mixed with the pulverized coal to obtain rapid ignition and to act as a transporter for the coal. This air is called the 'primary air'. The remaining portion of the air, or 'secondary air,' is introduced through registers in the windbox.

There are two fuel-burning systems used frequently in pulverized-coal boiler designs. The two systems are:

- Wall-Fired: Smaller boilers have burners on one wall and larger boilers have burners on two walls; for example, front and back. A 250-MW pulverized-coal boiler usually has from six to ten burners on the front furnace wall.
- Tangentially Fired: Coal and air enter the furnace at the four corners.

With the wall-fired system, the coal is mixed with the combustion air in individual burner registers. The following figure shows this type burner:

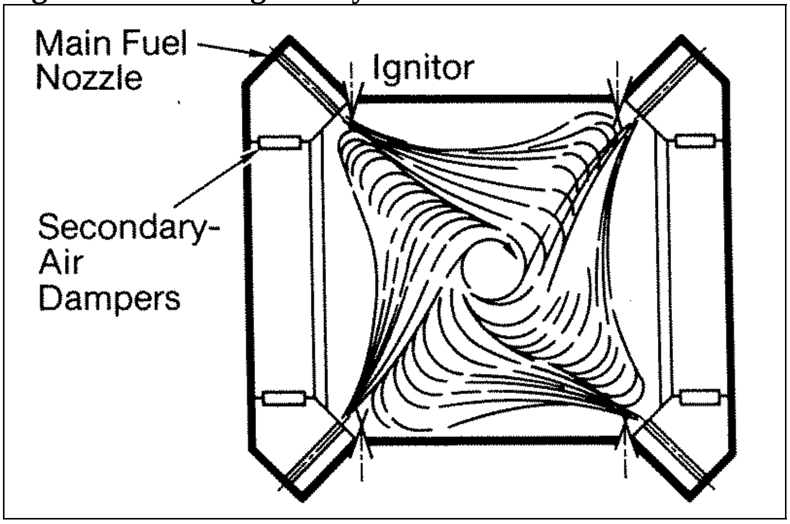
Figure 8: Wall-Fired Pulverized-Coal Burner



Reference: Babcock & Wilcox, Steam, page 13-5

With the tangentially fired burner design, the coal and primary air create a strong rotation within the furnace. The air swirl rotation along with the burner throat contour establishes a recirculation pattern extending several throat diameters into the furnace. Refer to the figure below:

Figure 9: Tangentially Fired Pulverized-Coal Burner



Reference: Combustion Engineering, Power, page 12-2 through page 12-4.

The vertical alignment of the fuel and air nozzles in the tangentially fired system can all tilt in unison to raise or lower the flame to control furnace heat absorption in superheater and reheater sections.

An important consideration today in the firing of pulverized coal is the minimization of nitrogen oxide (NO_x) formation. The emission of NO_2 and NO (which together are referred to as NO_x) is regulated by governmental authorities in many economies and has become a very important consideration in the design of fuel-firing systems. The most important design criteria relevant to the control of both thermal and fuel NO_x for coal firing are related to (1) the types of coals being burned, (2) controlling the rate of air mixing with the fuel in the early stages of combustion which will minimize the fuel NO_x, and (3) by operating at the lowest practical excess air, as well as by minimizing gas temperatures throughout the furnace through the use of low-turbulence diffusion flames and large water-cooled furnaces which will reduce the thermal-NO_x contribution to total NO_x. Coals with the lowest fuel-nitrogen and lowest fuel oxygen/nitrogen ratios generally will produce the lowest NO_x.

There are firing system modifications available that can help to reduce NO_x emissions. The modifications include adding overfire air to the firing system, which results in causing the fireball at windbox level to be at or below stoichiometric conditions. Low NO_x nozzles can also be installed that have design features minimizing the creation of NO_x when firing coals.

Excess combustion air reduces boiler efficiency. For the usual pulverized-coal firing situation excess air at the furnace outlet ranges from 15% to 30%. The quantity of excess air required in a particular case depends on:

- The physical state of the fuel in the combustion chamber
- The fuel particle size
- The proportion of inert matter present in the fuel
- The design of the furnace and fuel burning equipment

Major causes of burner and firing system performance degradation and refurbishment measures are outlined below:

Table 3: Burner System Upgrading and Refurbishment Measures

Degradation and Impact	Cause	Improvement and/or Refurbishment
Non-uniform combustion in the furnace and low boiler operating efficiency. Non-symmetrical heat transfer to waterwalls. Increased NO_x and carbon monoxide (CO) emissions are observed.	Burner and pulverizer deficiency resulting in poor fuel and air distribution.	Improve fuel and air distribution to each burner so each is equalized. Install on-line monitoring equipment capable of balancing the fuel flows when linked to the plant control systems. Inspect the burners and replace components as necessary. Install modified burners.
Boiler operation is inefficient and high exit-gas temperatures are observed.	While not the direct fault of the burners, excess air levels are high and excess air is not being optimized.	Install on-line flue gas instrumentation to monitor oxygen, CO, NO_x and temperature at the economizer outlet and have the operators adjust the burner coal and air flow as required.
Increase in unburned carbon is observed resulting in lower boiler efficiencies	Low NO_x burners have been installed which sometimes result in an increase in the level of unburned carbon	Same as above.

References: (Babcock & Wilcox, Steam, 1992, pages 16, 17, 21, 31; Combustion Engineering, Combustion Fossil Power, 1991, page 21-2.)

5.4 Boiler Sootblowers

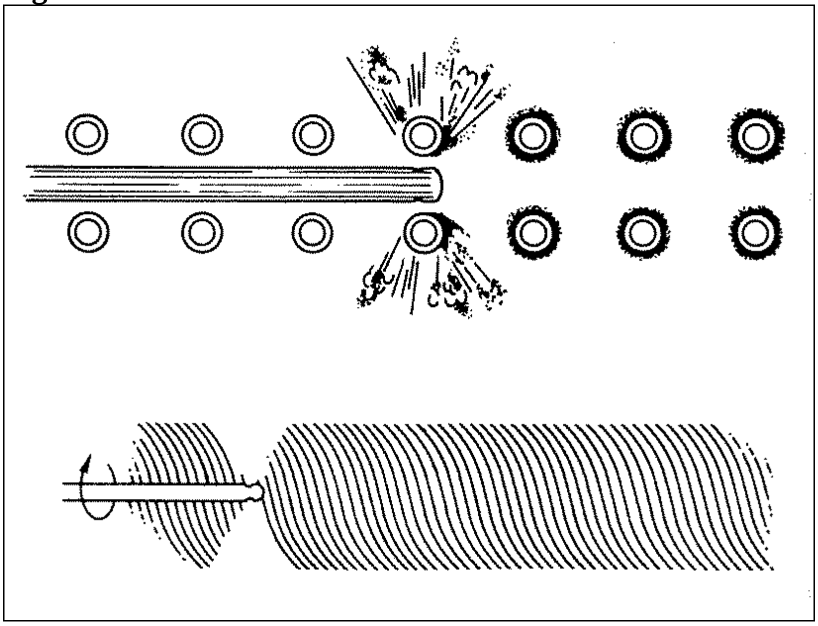
Improved or additional sootblowers increase furnace, superheater, and reheater heat absorption leading to increased boiler efficiency, reduced coal consumption and lower emissions.

One of the more important auxiliary boiler operations is the on-line fireside cleaning of boiler furnace walls, superheaters, reheaters, and the economizer sections.

The furnace walls are normally cleaned with short, single-nozzle retractable sootblowers called a wall blower. The single nozzle at the tip directs a supersonic high-energy jet of superheated steam or air parallel to the furnace face of the water-wall tubes dislodging the slag that has been deposited. Depending on the coal being burned, the wall spacing for the wall blower can vary. If it is anticipated that the design coal's slag is going to be more difficult to remove, the wall blower spacing will be decreased to account for this parameter. The frequency of blowing depends on the rate of slag build-up. The frequency of wall blowing every four to eight hours is common.

The superheater, reheater, and economizer sections are cleaned with long, fully or partially retractable lances that penetrate the cavities between the major heat-absorbing sections. The long retractable type sootblower has been found to be the most effective way of cleaning radiant and convective heating surfaces in the boiler. The retractable sootblower uses two 180°-opposed cleaning nozzles at the tip, which emit a high-energy jet of superheated steam or compressed air perpendicular to the lance. While the lance moves in and out of the boiler, it rotates, which forms a helical blowing pattern. Refer to figure below of a retractable sootblower:

Figure 10: Retractable Sootblower Lance



Reference: Combustion Engineering, Power, page 14-38.

The blowing media will either be steam or compressed air depending on a plant economic study that is normally conducted.

In systems with a large number of sootblowers, programmable controllers are installed so that the proper frequency and pattern of sootblowing can be conducted depending on operating experience with the coals being burned and the boiler characteristics.

Furnace cleanliness has a major effect on the efficiency and economics of a pulverized-coal power plant. The failure to repair a single furnace wall blower can easily be overlooked by a variation in fuel quality. The loss of heat transfer due to out-of-service retractable sootblowers in the convection section can be very significant.

Water cannons are newer equipment for cleaning furnace water walls of ash accumulation that impedes heat transfer from the burner flames. Many of the US coal plants operating with Powder River Basin coal from Wyoming and Montana have installed this equipment because conventional furnace wall sootblowers are not effective in removing the high calcium content ash that has a characteristic for reflecting the flame heat radiation. Many of the plants with this situation had low furnace heat absorption, which caused excessive steam temperatures and excessive slagging and fouling in the superheater and reheater surfaces. Water cannons direct a high pressure spray with high accuracy across the furnace where the water dislodges the ash upon contact due to the rapid formation of steam. A sophisticated instrumentation and control system to limit the water spray to areas with sufficient ash buildup because excessive spray will cause water wall tube damage.

Major causes of performance degradation due to sootblowers and refurbishment measures are outlined below:

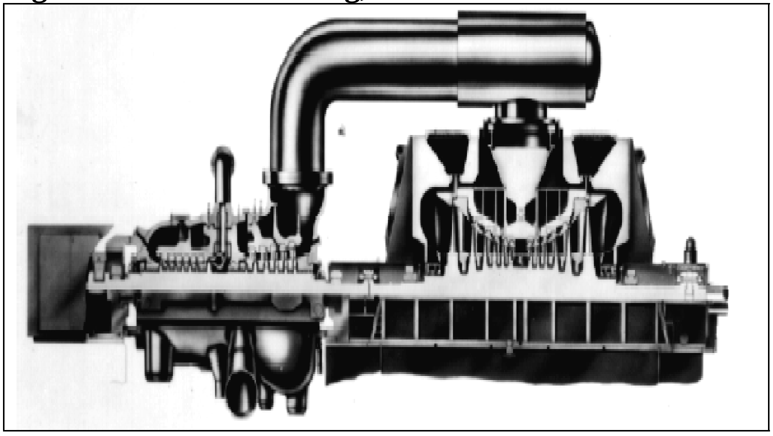
Table 4: Sootblower Upgrades and Refurbishment Measures

Degradation and Impact	Cause	Improvement and/or Refurbishment
Boiler experiences tube failures causing unit outages.	Slag accumulation on water walls, superheater, or reheater.	If coal is original design coal, some sootblower(s) may be inoperable. Repair sootblower(s) and return to operation. (Failures in sootblowers may involve their steam/air supply valves, or the sootblowers' nozzles may have eroded) Supplemental operation of particular sootblowers may also be required due a portion of the furnace configuration creating the need to operate some sootblowers more frequently. Regular boiler observations needed by the operator.
Boiler experiences tube failures causing unit outages.	Slag accumulation on water walls, superheater, or reheater.	If type of coal being burned varies from the design coal and is a higher-ash coal or if the coal has a lower ash-fusion temperature, additional sootblowers may have to be added or the sootblowing frequency may have to be increased because the new coal has increased slagging tendencies. Regular boiler observations needed by the operator.
Boiler is not operating efficiently and is not meeting design output.	Slag accumulation on water walls, superheater, or reheater causing poor heat transfer conditions.	See above two possibilities.
Boiler experiences water wall tube failures	Sootblower steam or water impinging on the tube.	Adjust the direction of flow from the sootblower nozzle.

5.5 Steam Turbines

Improved steam turbine performance increases plant efficiency and output, or reduces coal consumption for the same output. New steam turbines are about 3% to 8% more efficient than many old steam turbines. Many of the new turbine internal components can be installed within the existing turbines, replacing the existing components during the major turbine periodic overhauls to lessen cost and schedule impacts. New components are more reliable and can reduce maintenance costs by increasing the time between required internal inspections and overhauls. The following figure shows a steam turbine that is in the size range of 250 MW to 400 MW:

Figure 11:   Two-Casing, Double-Flow Steam Turbine with Off-Shell Valves



Reference: GE Power Systems, Steam Turbines for Large Power Applications, GEK 3646D

The following table provides a list of the major steam turbine improvements and refurbishment options.

Table 5: Major Steam Turbine Improvements and Refurbishment Options

Equipment / Component	Description	Potential Performance Improvement	References
Steam Turbine			Ref. 1, 2, 3
Rotating Blades and Stationary Vanes	Advances in design and fabrication technology have achieved efficiency improvements of the blade and stationary vane profiles for improved efficiency in converting steam energy to shaft torque.	2% to 8%	Ref. 2
Blade and Stationary Vane Sealing	Reduction of steam leakage in the clearance zone between rotating and stationary surfaces with new seal designs and configurations.	1% to 2%	Ref. 3
Full Arc or Partial Arc Main Steam First Stage High Pressure (Main Steam) Turbine Inlet	For most turbines, efficiency with a full arc design at full load will be higher than a partial arc design. However, the reverse is typical at lower loads even with sliding main steam pressure control. When an improved high-pressure turbine is to be purchased, selecting the best first stage design usually depends on how the unit will operate. However, full arc designs often experience less hard particle erosion with less efficiency deterioration with ongoing operation.	0.5% to 1%	Ref. 3
Shaft seal leakage	This leakage results in steam bypassing the turbine blades and a loss in turbine output and efficiency. Correcting excessive leakage involves replacing the deteriorated seals, but investigation of newer design seals that are more effective could improve turbine performance.	0.2% to 1.5%	Ref. 3
Optimum Last Stage Blade Flow and Condenser Pressure	Last stage blade (LSB) efficiency will initially increase with steam flow rate, but after a certain point, efficiency will begin to decrease with further flow rate increase. Lower condenser pressure will increase LSB performance and turbine efficiency	0.5% to 2%	Ref. 3
Modifications for Reduced First Stage Blade Erosion	First stage modified inlet nozzle and blade contours and coatings have reduced the loss of efficiency that occurs with ongoing operation from solid particle erosion (SPE). SPE results from boiler internal superheater and reheater tube scale.	0.5% to 2.5%	Ref. 3

References:

1. Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region – EWG 4/2000.
2. Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region – EWG 2/2001 – Phase II.
3. Advances in Steam Path Technology – GE GER-3713C

5.6 Condenser and Cooling Water System

Scaling on the waterside of the condenser tubes decreases the heat transfer coefficient and higher condenser pressures consequently result. Air leakage into the condenser can also increase condenser pressure. Increased condenser pressure will reduce steam turbine output and efficiency.

Steam from the turbine is cooled in the condenser to condensate, which is kept pure for reuse in the steam cycle while providing low backpressure to the turbine to maximize plant efficiency. Pulverized-coal power plants, for the most part, utilize water-cooled surface type condensers consisting of tube bundles containing cooling water encased in an airtight shell to prevent contamination of the condensing steam.

Condenser failures typically result from design deficiencies, corrosion failures of the materials used, fabrication practices, abnormal operating cycles, cycling of the unit, operating methods, and improper maintenance procedures. Regarding construction materials, condenser tube material is a big factor in the type and quantity of tube failures.

Condenser tubing materials are selected based on the cooling water medium and include most commonly include copper alloys, stainless steel, and titanium. The tube failures result from damage mechanisms such as pitting corrosion, stress corrosion, de-alloying, erosion, crevice corrosion at the tube to tube-sheet joint, mechanical damage from fretting and steam impingement and vibration, and galvanic corrosion. In each case, the tubes have to be replaced by re-tubing the condenser or repairs have to be conducted. In the case of improper material selection, the entire condenser may have to be retubed.

Major causes of performance degradation and refurbishment measures associated with Condensers are outlined below:

Table 6: Condenser Performance Degradation and Refurbishment Measures

Degradation and Impact	Cause	Improvement and/or Refurbishment
Leakage of air into the condenser causing an increase in backpressure in the steam turbine resulting in a higher heat rate as well as increased corrosion of the feedwater heaters, boiler and steam turbine.	Poor fabrication practices with inferior welding of the condenser shell allowing in-leakage of air.	Repair the inferior welds and inspect all welds for soundness.
Waterside (inside) of the condenser tubes are fouled causing poor heat transfer and increase in the turbine backpressure and resulting higher heat rate.	Poor maintenance practices along with poor water quality and lack of proper chemical treatments to prevent fouling of the tubes.	Improve the maintenance practices to clean the condenser tubes physically during outages. It is important that each tube be cleaned. Treat the cooling water chemically to minimize fouling of the tubes.

In addition to condenser degradation and refurbishment measures, cooling water pump, cooling tower and other cooling system equipment measures should also be considered. For example, pump flow rate deficiencies caused by pump inlet flow restrictions, pump impeller and seal wear or piping restriction may be causing high condenser pressures. River, ocean, and lake cooling water temperatures may be higher than required because of low water levels, river flow rates, recirculation from the discharge back to the cooling water inlet and other matters. Cooling tower fill deterioration often occurs which also results in high cooling water temperatures.

5.7 Boiler and Auxiliary Equipment Controls

Major advances in control systems have taken place steadily over the operating life of many pulverized coal plants. For example, a plant installed in the early 1980's probably had an analog boiler control system. Since, that time control system companies have provided successive new versions of distributed control systems (DCS) that are easier to program and tune for the specific boiler and current fuels. These digital computer systems provide more accurate control of boiler excess air, coal fuel flow, pulverizer operation, steam temperature control (e.g., tilting burners and desuperheaters), operating variables and improved operations monitoring. Improved programming optimizes boiler operations for startups, steam flow increase or decrease based on electricity output requirements, normal and emergency shutdowns. Improved operator interfacing, lower maintenance costs, greater operational safety, mitigated temperature and pressure transients result in lower induced stresses of the major boiler water and steam path components and other improvements are also provided. As a result, boilers are operated more efficiently, with lower emissions, more reliably and at lower cost.

Most coal plants have implemented a least one control system upgrade and some plants have had more than one upgrade from the original systems to more current controls. The prior APEC Reports summarized in Section 2 of this report and the listed references provide descriptions of control system upgrades.

Although current DCS capabilities have provided major improvements day to day boiler operations has shown the need for additional improvement. Typical current practice is to tune the boiler occasionally by adjusting DCS programming and coal feeder rates, pulverizer coal air dampers, coal pipe air and fuel distribution, burner air registers and dampers settings, steam temperature control and other components to achieve low emissions and high efficiency. However, examination of a typical boiler's NOx emission operating data shows measured values with significant variations even with a fairly stable coal supply, a properly operating DCS and recent boiler tuning. Fairly large variations in unit efficiency are also found.

New optimization concepts and control systems are now being installed that are showing major improvements in achieving sustained operations with low emissions. These control systems provide continuous operating optimization instead the limited to the optimization provided by the occasional boiler tuning. Adjustment of the operation of burners, steam temperature control equipment and components, soot blowers, pulverizers and other components respond to differences in coal, ambient conditions and equipment operating status that actually are occurring hourly or even more quickly. Coordinated boiler/turbine operation is provided. These new systems employ advanced monitoring and control concepts; including fuzzy logic, artificial intelligence, neural networks, sophisticated algorithms, and modeling of a large number of variables.

For example, lower NOx emissions and improved boiler efficiency can be achieved by continuously monitoring and adjusting pulverizer coal air temperature, ratio of primary to secondary air flows, burner to furnace windbox pressure, burner tilt and other steam temperature control adjustments, burner overfire air flow rates and furnace injection points, and sootblower operation. In addition, the boiler chimney can be monitored to implement control measures to reduce dust emissions and the algorithms or other control concepts can be adjusted to achieve low flyash carbon content reducing this loss in boiler efficiency. These systems require also additional instrumentation and additional actuators and other devices. The result is that the boiler and other equipment operations data is collected and analyzed by these control systems and ongoing adjustments are made to achieve more highly optimized operation. These systems make these adjustments based on accessing prior data to achieve the optimized setting for the current operating conditions. Operators may attempt to make these adjustments, but their actions often do not achieve optimized operation because ready access to past data is not available, limited current operating data, insufficient controls and actuators to make the needed adjustments and the need to attend to other matters.

Reports on these new systems indicate substantial benefits. For example, a project report on a neural network - sootblower optimization process (National Energy Technology Laboratory, Benefits of the Big Bend Power Station Project, John Rockey) showed annual emission reductions of about 3,000 tons/yr NOx, 58,400 tons/yr CO2, and other emission reductions based on improved boiler efficiency on this 445 MW wet bottom boiler. Additional benefits included, reduced boiler tube erosion damage and auxiliary power. The cost for this upgrade was about US$3,000,000 (~US5/kW). Annual operational cost savings were estimated to be US$908,000. Therefore, the upgrade costs would be recovered within slightly more than three years. Another report (Electric Power Conference 2005, NOx Control Implementation at Deseret Power, Bonanza Station) describes the implementation of burner neural network controls. This project reduced NOx emissions and improved on this 485 MW pulverized coal fired unit. About a 1% boiler efficiency and about a 20% reduction in NOx was achieved even with major changes to the coal heating value.

6. METHODOLOGY

There are many approaches in use for plant equipment assessments and plant operation improvement studies and implementation including: life extension, heat rate improvements, reliability improvements, reliability center maintenance and benchmarking. The methodology presented in this report is a simple, straightforward, comprehensive approach that can incorporate other assessment techniques. This approach incorporates plant operations and maintenance, upgrading and refurbishment performance improvements and costs. The steps are:

1. Assessment and prioritization of candidate equipment improvements.
2. Evaluation of the high priority improvements.
3. Ranking high priority upgrading and refurbishment improvements, and deciding which improvements will be implemented.

6.1 Step 1 - Equipment Performance Assessment and Prioritization

Preparation of a comprehensive table for the specific plant that identifies the equipment with operating deficiencies is the next step. Through the use of the equipment performance assessment table, (example provided in Section 7 of this report) equipment with appreciable operating deficiencies is identified. Initial assessments are developed for the major equipment on the list. High priority improvement opportunities are identified using key performance indicators. Explanations are provided in Section 7 on the use of the table. Prioritization of these opportunities leads to deciding which equipment will be evaluated. This leads to the next step: equipment evaluations.

6.2 Equipment Evaluations - Case Studies - Step 2

When viable options are identified and ranked for a specific plant based on the equipment assessments, the next step is to proceed with evaluations of the high priority equipment performance improvement candidates to determine estimated costs and benefits for implementing refurbishment and improvement projects. Report Section 8 provides example Case Studies. An Equipment Evaluation Spreadsheet is used.

Examples of equipment upgrading and refurbishment improvements are described below:

- Improved pulverizers often reduce unburned carbon, which is wasted fuel that becomes entrained with ash and reduce the amount of ash slag that collects on furnace walls and on superheaters and reheaters, reducing heat transfer and boiler efficiency. These ash accumulations can also result in overheating and corrosion of boiler tubes, causing failures that require boiler shutdown for repairs.
- Improved or additional sootblowers increase furnace, superheater, and reheater heat absorption leading to increased boiler and turbine efficiencies, reduced coal consumption and lower emissions.
- Reduced air heater leakage lowers FD and ID fan horsepower because this will reduce air and flue gas flows. Improved air heater performance will raise combustion air temperature and reduce flue gas temperature, which improves boiler efficiency. Improved

boiler efficiency and reduced air heater leakage reduces gas flow through the precipitator which will improve collection efficiency and reduce air emissions

- Improved steam turbine performance increases plant efficiency and output, or reduces coal consumption for the same output. New steam turbines are about 3% to 8% more efficient than many old steam turbines. Many of the new turbine internal components can be installed within the existing turbines, replacing the existing components during the major turbine periodic overhauls to lessen cost and schedule impacts. New components are more reliable and can reduce maintenance costs by increasing the time between required internal inspections and overhauls.
- With improved burners and instrumentation, more complete combustion of the coal with lower emissions is possible. In addition, with new burners and instrumentation, operators can adjust air and coal flow for complete combustion and low unburned carbon, water wall slagging and superheater/reheater slagging and fouling. These improvements result in better heat transfer within the furnace and improved boiler efficiency.
- Control and instrumentation improvements can reduce total fuel consumption due to quicker and more coordinated startups, and better control of fuel and air during normal operation.

6.3 Ranking of High Priority Improvements - Step 3

The Overall Prioritization Table provides for the assessment of efficiency, emissions, reliability, and operational benefits achieved by the specific improvement options. It indicates the relative cost effectiveness of efficiency improvement benefits, and identifies operations, maintenance, and emissions benefits. The cost benefit will be based on net benefits, which is the benefit minus the capital and other costs. Operational benefits are qualitative differences that will be listed for inclusion in the evaluation. Emission reductions will be determined and listed. Ranking the results of the equipment high priority improvements provides the basis for deciding the upgrading and refurbishment projects that will be implemented.

7. EQUIPMENT PRIORITIZATION - (STEP 1)

The following table is an example for determining the motivation (technical and economic drivers) and the justification for expecting improved performance applicable to the key pulverized-coal plant equipment and associated components. This table will assist in efficiently identifying the conditions that determine what equipment should be assessed for improvement and/or refurbishment as Case Studies. High-priority improvement opportunities will be identified using the table's key performance indicators. This table would be prepared for the specific plant by the personnel (with a suitable team name; e.g., the Upgrading and Refurbishment Team) given the task of identifying and evaluating performance improvements.

The following equipment, consistent with the scope of this study, is included in the following example plant equipment performance evaluation table. These equipment components usually provide opportunities for appreciable efficiency and reliability improvements:

- Air Heaters
- Pulverizers
- Burners
- Sootblowers
- Turbine
- Condenser

The following describes the purpose of each column:

A. **Equipment/Parameter:** This column lists the plant equipment that provides opportunities for cost effective efficiency, emission, and reliability improvements. The information shown in this example for the examples of equipment evaluations provided in this report is shown below:

B - D. **Indicators:** These columns describe key drivers and provide criteria for implementing the equipment improvement evaluation.

E. **Assessment Prioritization:** Developed during the plant assessment activity for each item of equipment.

F. **Availability:** Overall impact of the equipment recent performance is summarized. Since the boiler equipment addressed in this report, the air heaters, pulverizers, burners, and sootblowers, do not have a major impact on availability the list of key indicators is for the entire boiler.

G. **Operations and Maintenance**: Evaluation guidelines are entered in this column.

H. **Emissions:** Typical rates and discussions on improvements are entered in this column.

Table 7: Equipment Performance Assessment and Prioritization – Part 1

Equipment	**Key Operations and Economic Performance Indicators**			**Assessment Prioritization**
A	**B**	**C**	**D**	**E**
	Indicator 1	**Indicator 2**	**Indicator 3**	
Air Heaters	Air leakage more than 5% to 10% above design or above 20% in any case.	Gas inlet to outlet temperature difference within 15°C to 20°C of design or above 170°C in any case	Air temperature to the pulverizers and burners that is lower than design by about 20°C to 30°C. Pulverizer output limitations based on insufficient air temperature may need to be considered.	The assessment by the Upgrading and Refurbishment Team would be entered here.
Pulverizers	Overall 100% output within 10% of the design value with applicable adjustments for coal grindability and moisture.	Coal fineness less than 10% below design value; For example, 60% vs. 70% passing a 200-mesh screen based on the current coal and unburned carbon and furnace slagging within reasonable limits.	Coal spillage from the pulverizer pyrites discharge is minimal. Reasonably uniform coal and air flow to the burners. Adequate rejection and removal of pyrites.	The assessment by the Upgrading and Refurbishment Team would be entered here.
Burners	Flame length, color and position are proper; and no pulsation or vibration.	NOx emissions are within 10% of design value and below the environmental air permit requirements.	In conjunction with the air heater and pulverizer operation, excess air; For example, less than 25% is achieved with acceptable furnace slagging and other boiler operation requirements.	The assessment by the Upgrading and Refurbishment Team would be entered here.
Sootblowers	Furnace wall, superheater, reheater, and economizer surface cleanliness is within the boiler supplier's recommendations.	Furnace exit gas temperatures and flue gas temperature entering the superheater and other heat exchange surface sections are within the boiler designer's acceptable range.	Erosion of superheater and other surfaces is not causing tube failures due to the sootblower operating frequency, location or steam moisture.	The assessment by the Upgrading and Refurbishment Team would be entered here.
Steam Turbine	The results of a turbine test (Example: ASME Performance Test Code 6) with the design heat balances should show that the tested heat rate is within 4% of design.	The results of a turbine test should show that current maximum output is within 2% of the design output.	The results of a comparison of turbine test results with new turbine components is within 4% of the new turbine design or the maximum expected output. Also, the type of turbine (for example, partial or full arc) is compatible or optimum for the planned unit operation.	The assessment by the Upgrading and Refurbishment Team would be entered here.

Equipment	Key Operations and Economic Performance Indicators			Assessment Prioritization
A	**B**	**C**	**D**	**E**
	Indicator 1	**Indicator 2**	**Indicator 3**	
Condenser	Operating pressures are high because of scaled tubes, excessive number of plugged tubes or air leakage into the condenser.	Cooling water leakage into the condenser results in poor water quality to the boiler and steam quality to the turbine.	Inadequate cooling water flow because of pump deficiencies, water intake or discharge problems, and excessive piping pressure loss. Also, increased cooling water supply pressure from the river, cooling tower or other source.	

Table 8: Equipment Performance Assessment and Prioritization – Part 2

Equipment	Key Technical and Economic Performance Indicators			Assessment Prioritization
A	**F**	**G**	**H**	**E**
	Availability	**Operations and Maintenance**	**Emissions**	
Boiler	• Better than 90% availability. • Water and steam tubing temperatures are monitored as needed and are not excessive. • There is a program for steam drum and main headers non-destructive testing (NDT) examinations based on the age of unit, materials and operating conditions.	• Operating staff follows manufacturer's startup, shutdown and other operation manual recommendations to control fuel consumption.	• Emissions (NOx, CO) are no more than 5% greater than the contract performance values or for similar units firing similar coal.	

Equipment	Key Technical and Economic Performance Indicators			Assessment Prioritization
A	**F**	**G**	**H**	**E**
	Availability	**Operations and Maintenance**	**Emissions**	
Turbine Generator	• Better than 95% availability. • Steam supply temperatures and quality is within equipment supplier's recommendations. • There is a program for shaft, blade and other NDT examinations based on the age of unit, materials and operating conditions.	• Operating staff follows manufacturer's startup, shutdown and other operation manual recommendations to control thermal stresses.	• Not applicable.	
Condenser	Condenser tube plugging and leaks are not occurring resulting in less than 99.5% average availability.	Tube scaling and water thickness measurements show no major deterioration. Tube plugs are mapped to show if there are failure trends that need to be investigated.	• Not applicable.	

8. CASE STUDIES - (STEP 2)

Air Heater, Turbine and Condenser example Case Studies are provided in this section of the report. These case studies incorporate the applicable reference information provided in Section 5 and the improvements listed in Sections 6 and 7 of this report.

Generally, it is well known that many generating units are NOT operating reasonably close to the original design efficiency. Therefore, excessive fuel consumption and CO_2 and other emissions result. Inadequate generating unit maintenance budgets are usually the reason for this situation. Obviously, maintenance expenditures have to be prioritized to first fund activities needed to remedy impending equipment failures for maintaining generating unit reliability. However, these case studies show that performance improvements can reduce operating costs that economically justify the upgrading and refurbishment expenditures and reduce CO_2 and other emissions

The first case study is for an air heater upgrade and refurbishment. This study, Case 1, provides two economic evaluation examples: 1) a simplified net present value and 2) a more detailed equivalent capital investment evaluation. The evaluation period is ten years, which is a typical evaluation period for these projects. After approximately six to twelve years it is expected that the air heater refurbishment activity would have to be repeated to maintain reasonable performance because of the erosion and corrosion that occurs within the air heater from the ash and sulfur in the flue gas flowing through this equipment. Periodic air heater refurbishment is often not scheduled and budgeted as should be although air heater performance degradation is a well known cause of generating unit reduced efficiency. Also, there are upgrades to older designs that improve the performance of this equipment over the original performance that should be included in the planning for this type of project during a regularly scheduled generating unit maintenance and repair outage.

The second study, Case 1, which uses a levelized cost savings and an equivalent capital cost evaluation method, is for a turbine upgrade and refurbishment. The types of steam turbine upgrading and refurbishment projects range from quite minor with low capital costs to extensive with high capital cost. Examples, of simple refurbishments are to replace eroded blades, clean off deposits on blades, repair or improve shaft seals. Expenditures for these types of activities, which are often low, are usually easily justified by the operating cost (mainly fuel) savings. Major refurbishment or upgrading projects often include replacing older blades with newer more efficient blade designs. Installing new blades can improve turbine efficiency by 2% to 8%. However, the cost is often high because a turbine internal section, shaft and other major components are usually needed.

The search for turbine cost information for Case 2 did not provide suitable information. A reference search and responses from more than eight sources who work in a variety of positions within the steam turbine sector of the power industry was that this cost information has been confidential because of the generating unit owner's and/or turbine manufacture's preferences. Based on this situation, this case study was prepared to show the development of operating cost savings and the resulting capital cost that would be justified.

Another significant observation is that the economic justification of turbine upgrades on larger generating units is usually easier than for smaller units because the refurbishment cost on a cost (i.e., US$/kW) basis for larger unit is significantly lower than for a smaller unit. However, as shown in this example, the economic justification for upgrading a medium size generating unit steam turbine is substantial. Also, because older turbines often require shaft, blade or other major repairs, the high reliability and fuel savings of new components combined with the repair cost that would have been expended can show a strong economic justification for an upgrade and refurbishment project. The evaluation period is 15 years, which is often applicable for this type of project.

The third case study, Case 3, involves condenser upgrading and refurbishment. The activities involved include replacing the existing condenser tubes with improved tube materials, reducing air leakage into the condenser, and tube sheet leakage. This case study, for the removal of the buildup of calcium carbonate deposits on the inside (waterside of the tubes), provides a simple economic comparison between the fuel cost savings and the maintenance activity. In this example, the fuel cost savings for only one year are much greater than the maintenance expense. The improvement in operating efficiency because of the improvement in condenser cleanliness and reduced steam turbine exhaust pressure will decline with ongoing operation and the cleaning operation would have to be repeated periodically, but probably never more than once per year.

These three cases provide examples of a range of types of upgrading and refurbishment projects. Also, several types of economic analyses are presented for these three cases. However, the type of economic analysis is usually determined by the company, agency or other type of entity responsible for the power plant based on applicable policies and economics. Further, specific values and criteria to be used in the evaluations are often defined by local circumstances and financial/economic methodologies. These requirements would supersede the economic evaluation methodology presented in this report. The analyses range from simple to complicated. Often these analyses are kept confidential because of competitive business or other concerns. Most important is that the operating improvements and costs should be quantified and properly analyzed so that accurate performance, operational costs, electricity revenues and benefits may be determined.

8.1 Case 1 - Air Heater Case Study

8.1.1 Introduction

This case study is for upgrading and refurbishing a regenerative air heater. This upgrading and refurbishment includes replacing heat exchange surfaces and seals. Please refer to Section 5.1 earlier in this report for information on regenerative type air heaters. Operating data, capital costs and electricity revenues have been defined and calculated emission reductions are shown in this section.

The following economic spreadsheet table shows the expected reductions in fuel, ash disposal, and other costs, and increased electricity revenues that provide a simulation of the actual annual cash balance sheet. Two economic evaluations are shown; 1) present worth and 2) equivalent capital costs. These economic evaluation methods and input values need to be adjusted for specific projects and for the required economic parameters.

8.1.2 Operating Data, Capital Costs, and Electricity Revenues

The table below shows the typical applicable operating data for the unit and the air heater. These data were developed based on project team experience with air heater studies. Auxiliary power (plant electrical consumption for pump, fan, conveyor and other motors, plus transformer losses, lighting, ventilation and other uses) reduces the turbine generator output of a 150-MW unit to 143-MW net output to the electrical transmission system. The unit efficiency or heat rate is a reasonable nominal value for an older unit of this size.

The capital costs shown are based on past experience with air heater upgrading and refurbishment projects in the United States. However, the actual costs for a specific similar project may vary considerably based on the actual required refurbishment air heater components. Costs in some APEC member economies may be higher than shown because the replacement components are imported, and in other economies the costs may be lower than shown because they are supplied locally where manufacturing costs are lower. Also, the labor costs for the upgrading and repair work may be considerably different because of wage rate at the plant locations, or other situations. For example, some plants have dedicated repair and maintenance personnel whose costs are provided for on an overall station funding basis and whose expenses are not allocated to specific upgrading and refurbishment projects. This example shows costs for the upgrading and refurbishment work based on an independent contractor or a budgeted power plant repair and maintenance crew doing the work.

Estimating the value of the operating cost savings based on annual performance should be adequate for most projects. The coal cost and electricity revenue are considered appropriate for some but not all of the APEC member economies.

8.1.3 Emissions

Reduction in CO_2 and other emissions are also shown. A datum entry cell is provided for emission credit values. In most APEC member economies there will not be a cost or tax for boiler flue gas emissions, but this is shown in case it is needed now or possibly in the future.

8.1.4 Economic Evaluation Spreadsheet Table

It is important to recognize that for many upgrading and refurbishment projects the economic analysis is as important as the equipment or system engineering analyses. Often a sufficiently detailed engineering and economic analysis will show that the upgrading and refurbishment project provides positive economic returns on the associated expenses. This air heater case study reinforces the concept that upgrading and refurbishment investments effectively often pay for themselves and reduce CO_2, SO_2, and NO_x emissions by reducing coal consumption.

8.1.5 Economic Analysis Methodologies

A comprehensive discussion of the various types of economic analyses is not one of the original purposes of this report. However, this section provides a brief discussion with background information for the economic evaluation spreadsheet table presented in this report.

Methods for analysis of projects, proposals, and other special situations are described in many accounting textbooks. One source is the Electric Power Research Institute's Technical Assessment Guide, which is not available to the authors. Each methodology has advantages and disadvantages as briefly listed for some of the major types of analyses below:

a. Payback Period: is simple and easy to develop, but typically does not recognize the time value of money and cash flow after the payback period.
b. Accounting Rate of Return: easy to develop and understand, but typically does not recognize the time value of money and does not incorporate cash flow data.
c. Net Present Value (NPV): recognizes the time value of money and incorporates cash flows that vary from period to period, but requires a more detailed analysis than the previous two types of economic analyses.
d. Internal Rate of Return (IRR): considers the time value of money, is easy to compute using Microsoft Excel functions, but requires a more detailed analysis than the first two of the above types of economic analyses.

Net Present Value (NPV) is often preferable over the other types of analyses (e.g., type a and b above) because the present value of the refurbishment project is determined based on the time value of money and cash flows over a suitable future time period. The IRR method also incorporates the time value of money and future cash flows, but the results expressed as a percentage seem to be most often more applicable to manufacturing or other types of businesses rather than a power plant. Furthermore, in some cases NPV will provide a more accurate comparison between alternative projects. A positive NPV indicates that the project could be undertaken resulting in an overall improvement to the operating net revenues providing the analyses is a reasonably accurate representation of the actual balance sheet and future expenditure and revenues. The first economic analysis presented in the following table is the Net Present Value method.

"Most evaluations can be classified into two approaches. The first of these is often referred to as the "revenue requirements method." This method leads to a comparison of generating costs (or revenue requirements) on a cost /kwhr basis, between alternatives. The second method of performing an economic evaluation is what is often known as the "capitalized-cost method." (Reference: Combustion Engineering, Power, page 1-34 and 35). The capitalized-cost method is the type of analysis presented in this case study because it provides a comparison between the capital cost for the equipment or system upgrading and refurbishment and the savings justified by the improvements in operating costs. The project is economically favorable when operating cost savings exceed the capital cost for the equipment or system upgrading and refurbishment.

The evaluation period is an important issue. In this case study, 10 years was selected because of the usual expected degradation of air heater performance over this time period often justifies subsequent refurbishment. Air heater refurbishment should be scheduled when other major equipment refurbishments are scheduled; e.g., usually the turbine and boiler. Often turbine inspections and overhauls are scheduled periodically at four to twelve year intervals. The air heater design and type of coal usually determines the optimum air heater refurbishment schedule. Certain regenerative air heater designs and material selections will have slower rates of performance degradation. Coal that is corrosive and abrasive will cause more rapid air heater performance degradation. In this evaluation it was assumed that air heater performance deteriorated to approximately the starting point in ten years.

The following table shows the spreadsheet that was prepared for the upgraded air heater system on power plant performance, operating costs, and cash flow over a 10-year period. This spreadsheet includes the following:

- To accurately capture the economic effects of the upgrade, the spreadsheet incorporated key performance criteria (for example, auxiliary power, heat rate, boiler efficiency, coal consumption, CO_2 emissions) and operating-cost data (for example, coal purchase and ash disposal).

- To more readily observe the most pertinent effects of the upgrade, average net generation output was held constant to focus on the effect on CO_2 rather than on increased power production.

- Net present value was calculated using a discount rate of 10%. "This is the cost of money for a power system owner and includes the weighted cost of capital for each class of debt and equity" Reference: (Babcock & Wilcox, Steam, Page 37-5). This percentage is typical for many plants.

- An additional factor considered here relates to emission credits. Emission credits or tax differences should be included in the evaluation if applicable to the plant. Some plant owners will be able sell surplus emissions allowances that result from an upgrade (that is, the upgrade reduces emissions below the cap or maximum limit applicable to the plant) and others will reduce this expense. In this case it was assumed that SO_2 credits would be sold for US$100/tonne beginning in 2010. It is noted that the current value of SO_2 credits in the USA is about three or four times this amount.

8.1.6 Air Heater Case Study Spreadsheet Table

The data within the following five tables have two primary sections: the input data (first two tables) and the resulting data (last three tables). Most fields are simple mathematic calculations, such as “Net Revenue Increase”, “Additional Electricity Sales”, “Coal Savings”, “Fuel Savings”, “Ash Disposal Savings”, and “Emission Credit Cost Savings”.

Some of the input data would be computed through engineering calculations or the use of technical performance programs or proprietary simulation software. Examples of such data are the fields for “Net Plant Efficiency”, “Exit Flue Gas Temperature”, coal consumption, and emissions information. The scope of the calculation for these data points is beyond the intent of this report.

Net Present Value Method

In the first economic analysis method provided in the following table the Total Operating Cost Savings are determined using the net present value calculation for the applicable expenses over the selected time period. It is critical that a basic present value computation be made for each item of appreciable savings. The resulting present value using the applicable interest or discount rate of all of the operating costs is compared with the capital cost. If the savings are more than the capital costs the upgrading or refurbishment project is economically justified. In this analysis operating expenses and capital expenditures are considered similar. This is mainly true for power plants that do not have appreciable expenses for debt financing, insurance, property and income taxes, and depreciation.

The calculation for present value is based upon the following formula (Combustion Engineering, Combustion Fossil Power, 1991: page 1-34), which calculates a "Present Value Factor" to be multiplied by each year's future value, yielding a converted present value result:

$$PVF = (1) / [(1 + r)^{t}]$$

Where PVF = Present Value Factor
r = Discount or Interest Rate
t = time in the future

Equivalent Capital Expenditure Method

In the second economic analysis method presented in the following table, the Equivalent Capital Expenditure is determined. Operating and capital expenditures must be placed on the same basis to be combined for comparison purposes. For example, a major capital cost expenditure will often include a carrying charge on a company's annual balance sheet. "Annual costs such as fuel and O&M are divided by the fixed charge rate (i.e., capitalized) so that the result can be combined with capital costs." This gives a very quick way of comparing the difference in operating costs with the difference in capital costs between various alternatives". (Reference: Combustion Engineering, Power, page 1-35).

Fixed charge components include return on investment, capital recovery or depreciation, property taxes and insurance as well as federal and state taxes. These are calculated based on income taxes (Reference: Babcock & Wilcox, Steam, Page 37-5). This can be a complicated calculation requiring input on taxes, insurance, discount rates and other financial parameters. Fixed charge rates generally vary from about 6% to 20%. Plants owned by government entities usually use lower fixed charge rates and independent power plants require higher rates. The fixed charge rate used in this example is considered a conservative average; i.e., less favorable towards proceeding with the upgrading and refurbishment project.

The calculation of levelized operating expenses, which is needed to calculate the Equivalent Capital Expenditure, is shown below. ""To obtain levelized costs, it is only necessary to divide the total present worth of the payments involved by the sum of the present worth factors." (Combustion Engineering, Combustion Fossil Power, 1991: page 1-34).

$$LC = \Sigma C_i / (1+ r)^{t}] \ / \ [\Sigma (1 / 1 + r)^{t}]$$

Where LC = Levelized Total Costs
C_i = Cost at a point in time

Levelized Annual Cost is divided by the Fixed Charge Rate to be on the same basis as Capital Costs.

Equivalent Capital Operating Cost or Savings Expenditure = LC /Fixed Charge Rate

The Equivalent Capital Operating Cost (actually Savings) is compared with the Project Estimated Capital Cost. The project is economically favorable when the equivalent capital operating cost savings exceed the capital cost for the equipment or system upgrading and refurbishment

Similar analysis methodology can be employed for other plant equipment upgrades as demonstrated in the other two Case Studies provided in this report.

The resulting data will be used in determining which improvement actions should be implemented.

Table 9: Air Heater Case Study – Input Data – Part 1

Introduction:

1	This spreadsheet table shows the Air Heater Case Study evaluation results using present value economics.
2	This case assumes unit nominal average gross output does not change with the improvement in equipment performance.
3	Other economic analyses are available, but this approach identifies the appropriate costs over the proper time frame.
4	The report provides a detailed explanation of the development and use of the economics shown in this spreadsheet. References are also provided.
5	The costs shown below will have to be modified for a specific project. It might be appropriate to delete some costs and add others.
6	All the costs, but especially fixed charge rate, project overhead, and construction labor costs change significantly between economies.
7	The performance data is typical for a unit that has a poorly performing air heater.
8	The costs should be reasonably accurate for most APEC economies and for the size and type of air heater on many of coal plants.

Operational Data

Parameter	Units	Initial Poor Air Heater Condition	Improved Air Heater Condition	Improvement Over Initial Condition	Discussion
Average Annual Operating Time	%	70%	70%		
Operating Load	%	100%	100%		

Parameter	Units	Initial Poor Air Heater Condition	Improved Air Heater Condition	Improvement Over Initial Condition	Discussion
Average Nominal Gross Output	kW	150,000	150,000	0.0	Reference Note 2
Auxiliary Power	kW	8,200	8,000	-200.0	
Average Net Plant Output	kW	141,800	142,000	200.0	
Net Plant Eff. - HHV	%	31.5%	32.2%	0.6%	
Plant Heat Rate	kJ/Kw hr	9,710	9,520	190.0	
Exit Flue Gas Temperature	C	130	124	5.6	
Air Heater Leakage	%	40	12	28.0	
Boiler Efficiency - HHV	%	83.0	84.6	1.59	
Coal Consumption	Tonne/hr	86.9	85.3	1.64	
Coal Ash to Disposal	Tonne/hr	6.10	5.98	0.11	
Coal Consumption	Tonne/yr	533,000	523,000	10,000	
Coal Ash to Disposal	Tonne/yr	37,400	36,700	700	
CO_2 Emission	Tonne/yr	935,000	917,000	18,000	
CO_2 Emission	Tonne/MW hr yr	1.08	1.05	0.02	
SO_2 Emission	Tonne/yr	5,116	5,020	96	
NOx Emission	Tonne/yr	1,282	1,258	24	

Table 10: Air Heater Case Study – Input Data – Part 2

Economic Analysis Input

First Year of Analysis	Year	2005	
Number of Hours in One Year	Hours	8,760	
Base Year Electricity Price	US$ / MW	35.00	
Electricity Price Increase Over Base Year	%	2.0%	
Assumed Fixed Charge Rate or Carrying Charge	%	15.0%	
Discount Rate (for PV Calcs)	%	9.0%	
Annual Coal Price Escalation	%	3.0%	
Base Year Ash Disposal Cost	US$/tonne	8.00	Includes system maintenance
Annual Ash Disposal Cost Escalation	%	3.0%	
Value of SO_2 Emission Credit Savings	US$/tonne	150.00	Assumed to begin in 2010
Annual Emission Credit Escalation	%	3.0%	

Fuel Costs		Initial Poor Air Heater Condition	Improved Air Heater Condition	Improvement Over Initial Condition
Coal Cost - First Year	US$/Tonne	35.00	35.00	
Coal Cost - First Year	US$	18,655,000	18,305,000	-350,000

Capital Costs		Units	
Air Heater			
Secondary Baskets		US$1M	0.251
Secondary Seals & Basket supports		US$1M	0.136
Replace Seals		US$1M	0.038
Labor		US$1M	0.255
Subtotal		**US$1M**	**0.680**
Primary Baskets - Hot, Intermediate & Cold		US$1M	0.110
Primary Seals & Basket supports		US$1M	0.072
Replace Seals		US$1M	0.019
Labor		US$1M	0.101
Subtotal		**US$1M**	**0.302**
Total Capital Cost (TCC)		US$1M	0.982
Project Financing Costs - TCC x rate of	15%	US$1M	0.147
Project Overhead Costs TCC x rate of	25%	US$1M	0.246
Total Project Cost		**US$1M**	**1.375**

Table 11: Air Heater Case Study – Results – Part 1

(Note Columns for Years 6 through 9 are omitted)

		Base Year						**TOTAL**	
Year		2005	2006	2007	2008	2009	2014	**Present**	
		1	2	3	4	5	10	**Value**	
Electricity Output Increase	Units								Comments
Hours per year	Hours	8,760	8,760	8,760	8,760	8,760	8,760		
Average Unit Operating Time	%	70%	70%	70%	70%	70%	70%		Based on Input data
Average Output When Operating	%	100%	100%	100%	100%	100%	100%		Based on Input data
Increased Output - With Assumed Degradation	MW	0.20	0.18	0.16	0.14	0.12	0.07		The assumption is for the same improvement.
Increased Annual Output	MW Hrs	1,226	1,090	969	861	766	425		
Increased Electricity Revenue									
Electricity Price Increase Over Base Year		0.0%	2.0%	2.0%	2.0%	2.0%	2.0%		Assumption is uniform price increase.
Average Annual Electricity Price	US$/MW	35.00	35.70	36.41	37.14	37.89	41.83		
Escalated Electricity Sales Value	US$1M	0.043	0.039	0.035	0.032	0.029	0.018		Units are in millions of US dollars.
Increased Income / Revenue Tax	15.0%	0.006	0.0058	0.0053	0.0048	0.0044	0.0027		Assumption is uniform tax rate.
Net Revenue Increase, Additional Electricity Sales	US$1M	0.036	0.033	0.030	0.027	0.025	0.015		
				Interest Rate		9%			
Present Value Factor - based on year end		91.7%	84.2%	77.2%	70.8%	65.0%	42.2%		
Add'l Electricity Sales, Present Value (Yr 2005)	US$1M	0.0335	0.0278	0.0232	0.0193	0.0160	0.0064	**0.167**	

Note: The preceding Present Worth Factors are used in the following cost itemization.

Annual Fuel Cost Savings		Base Year 2005	2006	2007	2008	2009	2014	**TOTAL Present**	Comments
Base Fuel Consumption	1000 tonne/yr	533.00	533.00	533.00	533.00	533.00	533.00		Assumption is constant consumption over period.
Future Degradation Causing Increased Consumption	%	0.00	1.00	0.00	0.00	0.00	0.00		Assumed air heater performance degradation
Improved Coal Consumption - With Assumed Degrad.	1000 tonne/yr	523.00	524.25	525.34	526.30	527.14	529.99		Assumption is constant consumption over period.
Coal Consumption Reduction	1000 tonne/yr	10.00	8.75	7.66	6.70	5.86	3.01		
Fuel Cost Savings									
Coal Price Escalation		0.0%	3.0%	3.0%	3.0%	3.0%	3.0%		Assumption is a uniform coal price increase.
Coal Price	US$/tonne	35.00	36.05	37.13	38.25	39.39	45.67		
Coal Savings	US$1M	0.350	0.315	0.284	0.256	0.231	0.137		
Total of Present Worth Factors		6.418							
Present Value Factor		91.7%	84.2%	77.2%	70.8%	65.0%	42.2%		
Fuel Savings, Present Value (Yr 2005)	US$1M	0.3211	0.2655	0.2195	0.1815	0.1501	0.0580	**1.577**	

Table 12: Air Heater case Study – Results – Part 2

(Note Columns for Years 6 through 9 are omitted)

Operating Savings (including escalation rate)		Base Year 2005	2006	2007	2008	2009	2014	**TOTAL Present**	
Ash Disposal Before Improvement		37,400	37,400	37,400	37,400	37,400	37,400		Assumption is constant over period.
Ash Disposal After Improvement		36,700	36,700	36,700	36,700	36,700	36,700		Assumption is constant over period.
Ash Disposal Reduction		700	700	700	700	700	700		
Ash Disposal Cost Escalation			3.0%	3.0%	3.0%	3.0%	3.0%		Assumption is a uniform cost increase.
Ash Disposal Cost Savings - Including Maintenance	US$/tonne	8.00	8.24	8.49	8.74	9.00	10.44		
Escalated Ash Disposal Savings	US$1M	0.0056	0.0058	0.0059	0.0061	0.0063	0.0073		

Present Value Factor		91.7%	84.2%	77.2%	70.8%	65.0%	42.2%		
Ash Disposal Savings, Present Value (Yr 2005)	US$1M	0.0051	0.0049	0.0046	0.0043	0.0041	0.0031	**0.040**	

Initial SO2 Emission Before Improvement	tonne/yr	5,116	5,116	5,116	5,116	5,116	5,116		Assumption is constant over period.
Improved SO2 Emission After Improvement	tonne/yr	5,020	5,020	5,020	5,020	5,020	5,020		Assumption is constant over period.
SO2 Reduction	tonne/yr	96	96	96	96	96	96		
Emission Credit Escalation	tonne/yr		3.0%	3.0%	3.0%	3.0%	3.0%		
Escalated SO2 Emission Credit Cost	US$/tonne	150	155	159	164	169	196		

Escalated Emission Credit Cost Savings	US$1M						0.0189		

Present Value Factor		91.7%	84.2%	77.2%	70.8%	65.0%	42.2%		
Emission Credit Savings, Present Value (Yr 2005)	US$1M	0.0000	0.0000	0.0000	0.0000	0.0000	0.0080	**0.044**	

Other Operational Cost Savings - This section of the table would be used if there are additional cost savings.

___________ Before Improvement								
________ After Improvement	US$1M							
	US$1M							
___________ Cost Escalation								
_________ Cost Savings - Including Maintenance								
Escalated _________ Savings								

Present Value Factor		91.7%	84.2%	77.2%	70.8%	65.0%	42.2%	
Other Op Cost Savings, Present Value (Yr 2005)	US$1M	0.0000	0.0000	0.0000	0.0000	0.000	0.0000	**0.000**
Total Operating Cost Savings, Present Value (Yr 2005)	US$1M	0.005	0.005	0.0046	0.004	0.004	0.011	**0.084**

Table 13: Air Heater Case Study – Results – Part 3

Net Present Value Method

Estimated Capital Cost	US$1M	-1.375

Increased Elect. Revenue	US$1M	0.167
Fuel Savings	US$1M	1.577
Operating & Maintenance Savings	US$1M	0.084
Maintenance Savings	US$1M	0.000
Net Present Value of Operating Cost Savings	**US$1M**	**1.829**

Net Present Value	**US$1M**	**0.454**

The above NPV shows that the capital expenditure provides a positive Net Present Value that economically justifies this project.

Equivalent Capital Cost Method

Net Present Value of Operating Cost Savings	US$1M	1.829
Total of Present Worth Factors	US$1M	6.418
Levelized Annual Operating Cost Savings	US$1M	0.285
Fixed Charge Rate	US$1M	15.0%
Equivalent Operating Cost Capital Investment Savings	US$1M	1.8997
Estimated Capital Cost	US$1M	-1.375

Equivalent Capital Investment Difference	**US$1M**	**0.525**

The above Equivalent Capital Cost Savings shows that the capital expenditure economically justifies this project.

8.1.7 Results of Analysis

The analysis demonstrated that the upgraded air heater system favorably affected power plant performance, operating costs, and revenue over the 15-year period considered. Table 9 Operating Data shows the coal consumption, ash disposal and electrical output improvements. The calculated CO_2 emission reduction is 18,000 tonnes per year. Other emission improvements are also shown.

Table 10 presents the economic parameters assumed and the estimates of capital costs.

Tables 11 and 12 show the results of the present worth calculations for the additional electricity revenue and the operating cost differences.

The economic analysis results are shown in Table 13. The results of the NPV Present Value Method is about US$450,000 savings after deducting the Estimated Capital Costs.

However, the Equivalent Capital Cost Method which adjusts the NPV of the cost savings to an Equivalent Capital Cost value shows that this upgrading and refurbishment project is more than justified by an Equivalent Cost amount of approximately US$500,000.

8.1.8 Discussion

While not an examination of an actual project, the air heater case study employed typical criteria, operating parameters, and capital expenditures for this type of project. The result of the air heater case study speaks well for the feasibility of relatively low-cost upgrades of aging coal-fired power plants, which seek to reduce CO_2 and other environmentally harmful emissions.

8.1.9 Summary

While it is recognized that there may be major differences between this example and a specific power plant, these data are considered to provide a representative example for a fairly large number of units located in the APEC region. This example shows that if the air heater on the pulverized-coal plant is performing poorly (and experience indicates many are performing poorly) upgrading and refurbishment of this equipment provides both significant economic benefits and CO_2 reductions.

8.2 Case 2 - Steam Turbine Case Study

8.2.1 Introduction

This case study is for replacing an existing high / intermediate section of a steam turbine. Please refer to the prior Sections 5.5, Table 5, Section 6 and Section 7 and Table 7 in this report for information on steam turbine upgrading and refurbishment options and project prioritization. Turbine performance improvement, fuel and cost savings are provided for this case. Estimated CO_2 emission reductions are also provided.

The assumed existing and improved turbine generator turbine performance is shown below. The configuration of steam turbines with the output assumed in this case usually have combined high pressure and intermediate pressure sections (i.e., one casing and shaft - please refer to Figure 11). Therefore, this analysis assumes that both are replaced.

Changes to the boiler operation are assumed to be negligible. Also, increased electrical output is not included, but could be appreciable.

8.2.2 Operating Data

The table below shows the assumed design and operating data for the turbine generator. The parameters include the design and degraded heat rate for a typical older unit. Heat rate improvement is based on a 4 to 6% high and intermediate pressure turbine section efficiency improvement. This average efficiency used accounts for the impact of the high- and intermediate-pressure turbine efficiency on the overall turbine heat rate and future degradation of the new section.

Table 14: Turbine Design and Operating Data

Assumed Turbine Operating Data		Initial	Improved
Design Turbine Heat Rate	kjoule/kWh	8760	
Current Performance Degradation		4.0%	
Current Turbine Heat Rate	kjoule/kWh	9110	
Average Heat Rate Improvement with High Pressure Turbine Section Replacement			2.0%
Average Improved Heat Rate	kjoule/kWh		8930
Assumed Boiler Efficiency		84.0%	84.0%
Auxiliary Power		5.0%	5.0%
Heat Rate	kjoule/kWh	11,410	11,180
Heat Rate Improvement	kjoule/kWh		230

8.2.3 Fuel Cost Savings

The table below shows the assumed unit operating data, calculated fuel consumption and resulting fuel costs. Unit operation and fuel costs vary significantly at each generating unit, but the values shown are considered to be reasonable assumptions.

Table 15: Turbine Design and Operating Data

		Initial	Improved
Average Output - Assumed	kW	250,000	250,000
Average Capacity Factor		70.0%	70.0%
Yearly	kWh	1,533,000,000	1,533,000,000
Fuel Consumption	1000 tonne/yr	7,537,512	7,387,321
Fuel Cost	US$/million kjoule	2.11	2.11
Annual Fuel Cost	US$	33,165,053	32,504,211
Savings	US$		660,842

8.2.4 Equivalent Capital Costs

The economic analysis presented here uses the equivalent capital cost method described in Section 8.1.5 and 8.1.6. The Levelized Annual Fuel Cost Savings Value (S) and the Uniform Annual Series Present Value Factor (SPVF) used in the Table 16 is obtained from the following equations (Reference: Babcock & Wilcox, Steam, 1992, page 37-7).

$$S = S_1 \left[((1+e)/(1+k)^n) / (k-e) \right] / SPVF$$

Where $S_1 =$ Initial Cost in Year 1
PVF = Present Value Factor
k = Discount or Interest Rate
e = cost escalation

$$SPVF = [(1 + k)^n - 1] / [k (1 + k)^n]$$

The results of this analysis are shown below:

Table 16: Economic Parameter and Analysis Results

Interest or discount rate		10.0%
Years for the evaluation period		15
Fuel cost escalation		3.0%
Levelized Value of S (annual sum)	US$	780,000
Fixed Charge Rate		15.0%
Equivalent Capital Investment	US$	5,200,000

8.2.5 Emissions

Reduction in CO_2, based on the operating data above and a typical Powder River Basin Coal analysis is approximately 32,000 tonnes per year. This is a reduction of about 2% from the original CO_2 emission rate. Other emissions would also be reduced.

8.2.6 Results of Analysis

Based on the data and analyses presented above, the installation of the new high / intermediate pressure results in a levelized annual cost savings of approximately US$780,000 and an equivalent capital investment cost of US$5.2M. Therefore, if the new turbine components and the installation work cost this amount or less, the project is economically justified. In addition, cost savings for future turbine maintenance and additional electrical output could also be included in the analyses that would improve the value of this upgrading and refurbishment. Further, additional electricity revenue, ash disposal and other costs might also be included. Although there is limited information available on turbine generator component costs, the equivalent capital costs shown here would probably be sufficient to proceed.

8.2.7 Discussion

This case study used actual project data and a simple comparison of fuel cost savings with the cost for cleaning the condenser tubes to obtain the savings. This case study showed another example that suggests that expenditures to restore a generating unit's efficiency to the design performance result in reduced emissions and an improvement to the plant’s financial returns.

8.2.8 Summary

While it is recognized that there may be major differences between this example and a specific power plant, these data and results are considered to provide a representative example for a fairly large number of units located in the APEC region. This example shows that steam turbine upgrading and refurbishment is likely to provide both significant economic benefits and CO_2 reductions.

8.3 Case 3 - Condenser Case Study

8.3.1 Introduction

This case study is for upgrading and refurbishing a steam turbine condenser. This upgrading and refurbishment is for cleaning the existing condenser tubes, which is frequently not done as often as justified by the resulting operating cost savings. Other maintenance/refurbishment activities for condenser performance improvement include eliminating air leakage into the condenser, improved venting of non-condensable gases (mainly air) within the condenser and replacing tubes that were plugged because of tube leaks. Please refer to the prior Sections 4.6 and 5.6 in this report for information on condensers and Table 7 in Section 7 for upgrading and refurbishment prioritization. Operating data, fuel cost savings and condenser cleaning costs are provided. Estimated CO_2 emission reductions are also provided.

The data and results for this case study were taken from an American Power Division (ASME) paper IJPGC 2004-52020, titled "Improving Condenser Efficiency with Innovative Scale Removal System Technology". These data are considered to be an accurate representative case because ASME technical papers are peer reviewed and this paper was prepared by a utility author (Jon T. Hansen, Omaha Public Power District Nebraska, USA) and the contractor (George E. Saxon, Jr., Conco). At this generating unit, located near Omaha, Nebraska, USA, cooling water from the Missouri River is pumped through the steam turbine condensers and returned to the river at a temperature about 8.3 ^{o}C (15 ^{o}F) higher than the incoming temperature. A hard calcium carbonate scale formed on the inside of the condenser stainless steel tubes after prior years of condenser operation without appreciable scale formation. This was a thick scale that greatly reduced the condenser cleanliness. The scale buildup caused a significant increase in the condenser operating pressure from about 6.7 MPa (2.0 in. HG A) to a range of 10.2 to 11.9 MPa (3.0 to 3.5 in. HG A). As a result the turbine heat rate increased about 630kJ/KWH (600 Btu / KWH). Additionally, the generating unit output had to be reduced during hot weather when electrical power was in high demand.

This study describes cleaning the tubes with Patented Tube Cleaners for correcting the problem. These cleaners have two rows of four wheels that break the hard scale for removal. The cleaners are sized to fit the tubes. With the unit shutdown so that the condenser tube sheets are accessible, high pressure water through a nozzle placed at the tube inlet forces the cutters through the tubes. At the tube end the cleaners are captured for reuse. After cleaning the condenser performance returned to design.

An alternative cleaning method would be to use chemicals to remove the scale. It would be the appropriate to investigate both the tube cleaner and the chemical cleaning method to determine which is best. It is noted that the chemical cleaning may result in a liquid waste disposal requirement. Both methods may produce results that are significant operational efficiency improvement.

A simple economic analysis prepared from the data presented is this paper is provided in this section of the report; i.e., comparing the annual fuel savings to the cost for the cleaning. The annual fuel savings greatly exceed the cost for the recovery of the reduced condenser performance. Additional operating cost savings and increased revenues from additional electricity output were not included in this study because it was clearly seen that the expenditure for the condenser cleaning is easily justified.

8.3.2 Operating Data, Fuel Cost Savings and Condenser Cleaning Costs

The table below shows the design and operating data for the unit and condenser and the cost for the cleaning and first year fuel cost savings provided in the above referenced technical paper:

Table 17: Condenser Design and Operating Data

Unit Rating - kW	125,000
No. of tubes	10,930
Tube Material	Stainless Steel
Apparent Cleanliness Before Cleaning	37%
Apparent Cleanliness After Cleaning	93%
Heat Rate Improvement kJ/KWH (Btu/kWh)	(395)
First Year Fuel Cost Savings	US$212,000

8.3.3 Emissions

Reduction in CO_2, based on the operating data above and a typical Powder River Basin Coal analysis is approximately 44,000 tonnes per year. This is a reduction of about 5.5% from the original CO_2 emission rate.

8.3.4 Results of Analysis

Based on the data presented in the paper presented for the number of personnel required for the cleaning work and the time required, it is estimated that the cost for condenser cleaning was about US$50,000. Based on the estimated first year fuel savings of about US$210,000 it is clear that this type of cleaning justified the required expenditure.

8.3.5 Discussion

This case study used actual project data and a simple comparison of fuel cost savings with the cost for cleaning the condenser tubes to obtain the savings. This case study showed another example that suggests that expenditures to restore a generating unit's efficiency to the design performance results in reduced emissions and an improvement to the plant's financial returns.

8.3.6 Summary

While it is recognized that there may be major differences between this example and a specific power plant, these data are considered to provide a representative example for a fairly large number of units located in the APEC region. This example shows that if the condenser on a pulverized-coal plant is performing poorly (and experience indicates many are performing poorly) upgrading and refurbishment of this equipment provides both significant economic benefits and CO_2 reductions.

9. RANKING OF HIGH PRIORITY IMPROVEMENTS - (STEP 3)

9.1 Introduction

Following the equipment evaluation phase as shown in the case study examples, the next step is to prioritize the improvements and refurbishment opportunities. The types of equipment identified by the methodology described above as candidates for refurbishment are assessed using the following table, a sample of which is shown below. It provides for the assessment of efficiency, emissions, reliability and operational benefits achieved by the specific improvement options. The table indicates the relative efficiency improvements, and identifies operations and maintenance, emissions reductions and cost effectiveness. The cost effectiveness is based on net benefits, which is the benefit minus the capital and other costs.

The following describes the purpose of each column:

<u>Equipment Effectiveness Assessments</u> – These entries accumulate the improvements that can be quantified in terms of monetary results:

A. **Equipment:** This itemizes the evaluated equipment.
B. **Efficiency:** The net annual estimated fuel savings for the identified equipment efficiency improvements.
C. **Reliability:** The additional estimated annual electricity generation increase or plant operating time increase based on reliability improvements.
D. **Operations and Maintenance:** Evaluation guidelines are entered in this column.

<u>Operational Assessments</u> – These are important improvements that cannot be readily quantified.

E. **Operational Improvements:** Operational improvements that make the plant easier to operate or with less impact to the environment.
F. **Emissions Reductions:** Emission improvements that reduce carbon dioxide and other emissions and/or waste disposal.
G. **Cost Benefit:** The net cumulative effectiveness based on the equipment improvement and the ranking methodology.

9.2 Deciding Which Improvements To Implement

When viable options are developed and ranked for a specific plant, the next step is selection of the equipment options to include in planning the refurbishment and improvement. Information developed in these two tables will greatly facilitate planning and implementation activities and equipment selection.

Table 18: Overall Prioritization Table

Equipment	Key Equipment Effectiveness Assessments			Operational Assessments		Cost Effectiveness
A.	B.	C.	D.	E.	F.	G.
	Efficiency	Reliability	Operating and Maintenance	Operational Improvements	CO_2 Emissions Reductions	Cost
1. Air Heater	+1.4%	Negligible Change	Slightly Reduced Coal and Ash Handling	Improved Precipitator Performance is to be Expected	- 16,000 tonne per year	Present Value is a Savings of US$2.2 million
2. Condenser	Later	Later	Later	Later	Later	Later
3. Turbine	Later	Later	Later	Later	Later	Later

10. OBSTACLES AND ENABLING FACTORS

As described in the referenced Phase 1 and Phase 2 APEC reports, APEC member government regulations and policies, and power industry initiatives and practices can motivate the implementation of upgrading and improvement projects for existing pulverized-coal plant coal plant operations. These improvements will provide CO_2, other air emission and waste disposal reductions and, in most cases, economic benefits.

The current situation, as reported in the Phase 1 report, is that many existing APEC pulverized-coal plants (Phase 1 Report E-4 category, page iv and others) are operating below expected efficiencies which results in producing an excess of approximately 165 million CO_2 tons per year. The Phase 2 Report Case Studies for the Banshan and Liddell Power Stations projects document significant CO_2 reductions and economic benefits resulting from upgrading and refurbishment projects.

The Phase 1 report cited the following (Category E-4, page 104): "Obstacles to this group of options, if they exist, may be associated with lack of information, operator training, limitations on the access to the required upgraded equipment or instrumentation, limitation imposed by the age of out-date design of components of the existing power plant equipment; or management and decision making processes that hamper adoption of plant improvements."

The Phase 2 report (page 67) cited the following: ”There is a whole range of factors that contribute to effective reduction in the release of carbon dioxide.” The Phase 2 Report Section 5 provides description for the following, which are quite applicable to improving pulverized-coal plant operations:

- 5.1 Government Attitude
- 5.2 Carbon Penalties
- 5.3 Development of Clean Coal Technologies
- 5.4 Communication and Technology Transfer
- 5.5 Implementation of Clean Coal Technologies (Applicable to new plants)
- 5.6 Transition to a Competitive Energy Market
- 5.7 Application to APEC Economies

The Phase 1 and 2 reports provide thorough descriptions of certain obstacles and enabling factors.

Various perspectives are valid, but an important perspective is that improvements to existing pulverized-coal plant operations have been addressed by various technical papers, utility plans, governmental initiatives, research and other organization programs, conferences, seminars and other venues for many years. These improvements have had various titles: heat rate improvement, reliability and availability improvement, reliability centered maintenance, life extension, emission reductions initiatives, operations and maintenance training, preventative maintenance programs, controls and instrumentation improvements. These improvement measures and programs have been successfully implemented at many plants. Therefore, it is appropriate to state that "technical" information and methods are available for almost all, if not all required pulverized-coal plant improvements.

An obstacle that seems to require greater attention, however, is that the upper level management, boards or officials seem to be generally unaware of the economic and environmental benefits for the type of projects that are addressed in the Phase 1 and 2 reports and in this report. As a result, opportunities to significantly reduce future plant operating and electrical generating costs, and emissions, are not recognized. The type of detailed evaluations, as in this report, that address plant performance improvements, equipment upgrading and refurbishment expenditures and economic and environmental benefits need to be utilized. More case studies reports that show sufficient detailed performance, cost and economic information, as presented in the Case Studies in this report, will help to correct this situation.

A related obstacle to consider in addition to those presented in the Phase 1 and Phase 2 reports is the typical pulverized-coal plant annual expenditure / budgeting situation. Because of the advancing age of many pulverized-coal plants funding for required repairs and maintenance has increased significantly. However, expenditures for these projects are often severely limited because of the concept that minimizing equipment costs will achieve low electricity generating costs. It comes to the point on many plants where only the highest priority upgrading and refurbishment projects are funded. As a result, there are many upgrading and refurbishment projects that don't get funded that are justifiable in terms of economic payback based on fuel and other savings, and which would provide CO_2 reductions. This funding, in many cases, is so severely limited that the needed studies and evaluations for determining what should be done or what would be an optimized improvement are not done.

As a result, overall pulverized-coal plant operating efficiency and reliability is substantially below achievable levels because of "short term" plant upgrading and refurbishment budgeting practices. For example, requiring that an upgrading and refurbishment project "payback" the expense for implementing the improvement within several years will result in many missed improvement opportunities. Power plants typically have service lives of 40 to 60 years that dictates long term economic and financial planning horizons that are different than typical practices for commercial and industrial facilities. The graph below, which shows the general concept of the impact of funding on power plant reliability, serves as an example of the concept for optimized upgrading and refurbishment funding.

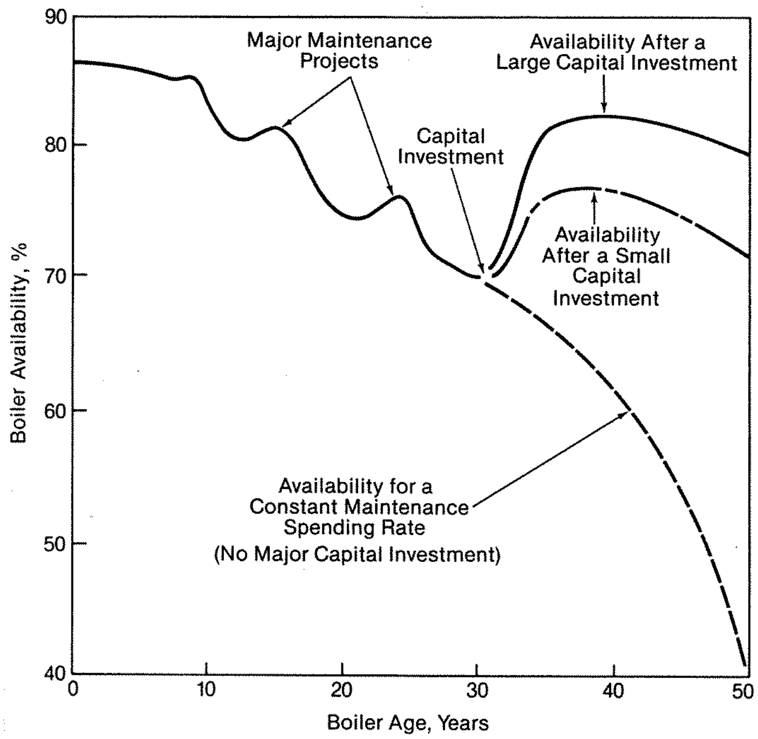


Figure 12: Typical Availability Curve for Large, High-Pressure Boiler

Reference: Babcock & Wilcox, Steam, Page 46-2

A new AEPC report that clearly shows how funding of upgrading and refurbishment projects reduces future electrical generating costs and CO_2 reductions may be quite beneficial. This report would show the relationships between optimized upgrading and refurbishment expenditures and generating costs. Examples of older plants with low generating costs that are operating with high efficiency and low CO_2 emissions would be sought out and their practices would be described in this new report. .

11. REDUCED CO_2 EMISSIONS AND UPGRADING AND REFURBISHMENT COSTS

This section addresses potential CO_2 emission reductions achievable through application of a range of upgrading and refurbishment options to the existing inventory of coal-fired power plants in the APEC member economies and the associated costs for achieving these reductions. This information supports the conclusion reached in the Phase 1 report that a CO_2 annual reduction of 165Mt is feasible. Also, this information supports the assertion that this reduction can be achieved at a cost benefit or at least at a zero cost.

11.1 APEC Region CO_2 Reductions

The following data (a portion of the entire table) was presented in the APEC Phase 1 report, page 68):

	Improvement	Net Efficiency Gain (% points)
Combustion System	Pulverizer and feeder upgrades	0.3
	Air preheater repair or upgrade	0.25
	Sootblower improvements	0.35
	Excess air I&C	0.2
Steam Cycle	Feedwater heater repairs	0.4
	Heat transfer tube upgrades	0.6
	Steam turbine blades	0.5
	Cycle isolation	0.5
	Condenser repairs	0.4
O&M	O&M training	
	Computerized maintenance and management systems and Reliability centered maintenance	Included in combustion and steam cycle gains. Efficient operation realized over the long term.
	Distributed control systems	
Combined Total		3.5

Based on the above data and the following bases, the Phase 1 Report shows a total potential CO2 reduction for existing coal-fired steam generating plants of 165 Mt per year based on the following:

- The total estimated MW capacity in the Combustion, Steam Cycle and O&M Improvements (E4) category and the estimated annual fuel consumption.
- 50% of the MW plant capacity.
- Average total plant efficiency increases of 3.5 percentage points obtained by combining the improvements listed per the data in the above table and the resulting 9% plant CO2 emission reductions (Phase 1 report Figure 4-1).

The data developed in this report and the references cited below indicate that the assumption of 3.5 percentage point heat rate potential improvement would probably be exceeded at many plants. The other bases above were not reviewed, but if accepted as presented indicate the estimated CO2 reduction of 165 Mt may be a low / conservative estimate.

Australian Greenhouse Office

The following table is from the Efficiency Standards for Power Generation Report, Australian Greenhouse Office, January 2000, page 38, prepared by Sinclair Knight Merz (SKM). These data are from surveys, SKM calculations and some plant specific data. The cost and CO_2 data that are also in this table were not used. It is noted that the efficiency improvements are not necessarily additive and that variations will occur based on the specific plant design and current performance. However, these data support the conclusion that the efficiency value of 3.5 percentage points assumed in the Phase 1 report is probably conservative. From other data and the results stated in the Phase 2 report the turbine blade improvement of 0.98 is low by a factor of at least two.

Efficiency Improvement

Action	Efficiency Improvement
Minimize boiler tramp air	0.42
Reinstate any feedwater heaters	0.46
Refurbish feedwater heaters	0.46 to 1.97
Reduce steam leaks	0.84
Reduce turbine gland leakage	1.1
Low excess air operation	0.84
Improved combustion control	1.22
Extra air heater surface in the boiler	0.84
Install high efficiency turbine blades	0.98
Install variable speed drives	1.97
Install new cooling tower fill film pack	1.97
Install on-line condenser cleaning system	0.84
Install intermittent energization to electrostatic precipitators	0.32

U.S. Environmental Protection Agency

The USEPA's report titled Efficiency Improvement Report dated April 17, 2001, found on the EPA's web site provided the following data based on efficiency improvements implemented by Wisconsin Electric Power Company. It is noted that the listed efficiency improvement projects are both related to plant operation and to equipment upgrading and refurbishment. These data also support the 3.5 percentage point average efficiency improvement used in the Phase 1 CO_2 estimated potential reduction.

Plant	Original Heat Rate (Btu/kWh - HHV)	Improved Heat Rate (Btu/kWh - HHV)	Efficiency Increase %	Description of Efficiency Improvement Projects
Oak Creek	9,802	9,4234	3.9	Variable pressure operation, distributed control system, retractable turbine packing, variable speed drives on the forced and induced draft fans, reduced air in-leakage, feedwater heater replacements, increased availability and capacity factor and precipitator energy management system
Pleasant Prairie	11,157	10,796	3.2	Variable pressure operation, unit and equipment performance monitoring, retractable turbine packing, reduced air in-leakage, increased availability and variable speed drive make-up eater pumps
Presque Isle	11,565	11,089	4.1	Retractable turbine packing, increased availability and capacity factor, reduced air in-leakage, reduced excess boiler O_2, boiler chemical cleaning, CO monitors on the boiler, improved turbine pressure and updated or additional instrumentation

It is noted that the some of the above Efficiency Improvement Projects are NOT the types that typically are expected to yield the largest cycle efficiency improvements. Therefore, these data could be considered as indicating that higher than the reported efficiency improvement would be possible at many plants.

The Phase 2 Report Case Study (page 25) for the Banshan Power Station, Hangzhou, Zhejiang Province, PR China described the improvement for a single 125 MW unit. This upgrading and improvement project included a turbine upgrade. The boiler improvements included reinstatement of the sootblowers and burner tilt mechanisms, reduction in excess air, furnace remodeling to reduce unburned carbon loss, improvement of mill maintenance, and air heater upgrading. The unit efficiency improved from 33.9% to 38.5%, a 4.6 percentage point efficiency improvement. It was noted that this unit is similar to more than 100 other units in China.

The Phase 2 Report Case Study (page 27) for the Liddell Power Station, New South Wales, Australia described the project for improving the steam turbine efficiency for the four 500-MW coal fired units, commissioned between 1971 and 1973. The 1960-vintage turbine low-pressure section blades were replaced which increased turbine efficiency 2% to 3%.

11.2 Upgrading and Refurbishment Project Costs

The cost information located from a data search on this topic is summarized below. There are a lot of references available, but it is noted that applicable sufficiently detailed cost data is not provided in most of these references. Detailed reporting is restrained because of the preference for confidentiality and for simplifying the presentations. However, the following information shows that it is reasonable to project that many upgrading and refurbishment projects would have either a negative or close to a zero net total cost result while achieving significant CO_2 reductions. The results of the Case Studies developed for this report also support this assertion.

The Phase 2 Report Case Study (page 25) for the Banshan Power Station reported an Annualized Capital savings of US$0.58 million.

The Phase 2 Report Case Study (page 27) for the Liddell Power Station reported an Annualized Capital savings of US$0.21 million.

The following table was prepared based on data from the Efficiency Standards for Power Generation Report, Australian Greenhouse Office, January 2000 pages 71 through 74. The Black and Brown coal plants produce over 94% of Australia's fossil fuel electricity generation.

Parameter	Black Coal	Brown Coal
Output - GWh / year	96,231	44,260
Output - % of Total	67%	33%
Average Cost - US$/tonne	25 to 35	4
GHG Reduction - %	2.0	3.4
Capital Expenditure – US$ M	148.8	171.7
Annual Fuel Savings - US$ M	27.7	9.0
NPV @10% Discount Rate - US$ M	77.4	-64.5

These datum show that the black coal plants producing about 67% of the power for these two types of plants could produce significant Green House Gas (GHG) reductions at an estimated positive Net Present Value of US$77.4 million. The estimate for Brown coal with lower fuel costs and higher capital expenditures shows a negative Net Present Value of US$64.5 million. However, a portion of the Brown Coal GHG reductions undoubtedly could be achieved at a positive or zero NPV. Therefore, although only one example, these data support the bases that over 50% of APEC existing coal fired generating plants could achieve a 3.5-percentage point CO_2 reduction at a positive or zero NPV.

Certainly not all plants will be able to achieve a benefit or zero cost results, but achieving the 165-Mt annual CO_2 reduction included the assumption that 50% of the APEC existing coal fired steam generating station capacity would achieve a 3.5-percentage point reduction.

11.3 Summary

In summary, based on the data provided below it is reasonable to expect that 50% of the APEC region plants would be able to achieve a 3.5-percentage point CO_2 reduction at a negative or zero net cost. This conclusion leads to the assertion that the 165-Mt CO_2 projected reduction would be achievable at approximately zero net cost.

12. SUPPORTING INFORMATION

12.1 References

Babcock & Wilcox, Steam, 1992

Combustion Engineering, Combustion Fossil Power, 1991

Combustion Engineering, Power, 1991

GE Power Systems, Advances in Steam Path Technology, GER-3713C

GE Power Systems, Steam Turbines for Large Power Applications, GEK 3646D

Integrating Consultancy – Efficiency Standards for Power Generation for the Australian Greenhouse Office (January 2000) prepared by Sinclair, Knight Merz.

International Energy Agency's (IEA) Clean Coal Center and the Australian.

Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, Prepared for APEC Energy Working Group, Expert Group on Clean Fossil Energy, Prepared by Levelton Engineering Ltd, November 2001, EWG 4/2000.

Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region (Phase II), Prepared for APEC Energy Working Group, Expert Group on Clean Fossil Energy, Prepared by HRL Technology Pty Ltd, December 2003, EWG 2/2001 – Phase II

Power-Gen Europe 1996, Modernisation of Rotating Matrix Regenerative Air Preheaters

12.2 Glossary

APEC	Asia-Pacific Economic Cooperation
ASME	American Society of Mechanical Engineers
$CaSO_4$	Calcium Sulfate
CEMS	Continuous Emissions Monitoring System
CO_2	Carbon Dioxide
CO	Carbon Monoxide
DCS	Distributed Control System
EGCFE	Expert Group on Clean Fossil Energy
EWG	Energy Working Group
FD	Forced Draft
FGD	Flue Gas Desulfurization
GW	Giga watt
HHV	Higher Heating Value
kJ	Kilojoule
kW	Kilowatt
kWh	Kilowatt hour
LSB	Last Stage Blade
NDT	Non-Destructive Testing

ID	Induced Draft
MW	Mega watt
NO_x	Oxides of Nitrogen
PV	Present Value
SCR	Selective Catalytic Reduction
SPE	Solid Particle Erosion
SO_2	Sulfur Dioxide
TCC	Total Capital Cost

12.3 Appendix 1

Introduction

Two prior APEC reports provide important information on carbon dioxide (CO_2) reductions:

1. Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, November 2001, Levelton Engineering, Ltd.

   The information in this report pertaining to pulverized-coal plants describes the amount of electricity generated, associated CO_2 emissions, potential for plant performance improvements and emission reductions, and other relevant information for this type of generating plant.

2. Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region (Phase II) HRL Technology Pty Ltd.

   This report included two descriptions (Case Studies) for projects that resulted in CO_2 emission reductions that are applicable to upgrading and refurbishing pulverized-coal plants. Enabling factors for CO_2 emission reductions and two reviews were provided for targeted economies: Malaysia and Vietnam.

This appendix provides references, described below, to the Phase 1 and Phase 2 reports relative to the information that is applicable to this report.

1. Options to Reduce CO_2 Emissions From Electricity Generation in the APEC Region, November 2001, Levelton Engineering, Ltd.

The Phase I Executive Summary of this Report states:

> “The principal goals for the study were: (1) to review current and emerging options to improve efficiency and reduce CO_2 emissions from burning fossil fuels to generate electricity; (2) to develop data on the status of current CO_2 emissions and CO_2 emission reduction measures; and (3) to determine the current effects of emissions from combustion of fossil fuels for electricity generation on air quality and health and the possible effects of CO_2 reduction options on air quality."

Phase I report information provided for improving existing CO_2 emissions and efficiency of coal pulverized plants, identified in this report as E-4 improvement scenarios, will be utilized in the preparation of the Upgrading and Refurbishment Report as summarized below:

1.1. Only the E4 category of plants applies to the Upgrading and Refurbishment report:

1.2. Page 12: Table 3-2, Energy Supply Indicators for APEC Economies shows coal reserves that will influence where coal will be used in existing pulverized-coal plants.

1.3. Page 14: Table 3-3, Electricity Generating Capacity and Annual Generation in APEC in 1998 shows where existing pulverized-coal plants output is likely to be most needed.

1.4. Page 19: Table 3-5, Input Energy Used in APEC Economies for Electricity Generation in 1999. This table provides coal consumption for the countries, which is the important data for projecting CO2 emission reductions based on the upgrading and refurbishment possibilities identified in this report.

1.5. Page 23: Section 3.5.1.1, Coal-Fired Technologies provides a brief description of types of coal generation. This section will be referenced in this report.

1.6. Page 31: Table 3-7, Distribution of Existing Capacity by Fuel and Type of Energy Technology for APEC Economies as of November 2000. This table provides generating capacity for the countries, which is the most important data from the Phase I report needed for the Upgrading and Refurbishment report.

1.7. Page 33: Table 3-8, Future Electricity Generating Facilities: Planned or Under Construction provides estimates of future total generation. This table is interesting, but does not apply to the scope of this report.

1.8. Page 42: Section 4.3, “Existing Plants”: Combustion System Improvements is a discussion on combustion improvements that will be referenced in this report or possibly included as an Appendix.

1.9. Page 49: Existing Plants: Steam Cycle Improvements is a discussion on turbine cycle improvements that will be referenced in this report or possibly included as an Appendix.

1.10. Page 68: Table 5-2, Illustration of Efficiency Improvement Package for Scenario E4: Shows approximate percentage efficiency increases for various pulverized-coal plant improvements that will be referenced in this report.

1.11. Page73: Table 5-5, Estimated CO2 Emissions by Technology Group for APEC Fossil Fuel Generation Based on UDI Database through 1998 shows APEC CO2 generation for pulverized coal-fired generating plants and other types of plants. This table will provide the basis for the CO2 estimated reductions required in this report.

1.12. Page 74: Table 5-6, Emission Basis for Assessing Effects of Scenarios E1to E5 shows the assumed pulverized-coal plant generation (E-4) that would be improved based on implementation of upgrading & refurbishment improvements. This estimate will be reviewed and adjusted if necessary.

1.13. Page 83: Table 5-10, Comparison of Emission Factors and Generating Costs for Technologies to 2010 Relative to Baseline Technologies shows generating costs that will possibly be useful when the cost justification methodology is developed.

1.14. Page 102: Table 6-6, Qualitative Rating of Emissions and Air Quality Co-Benefits for CO2 Emission Reduction Scenarios Analyzed in the Study shows how efficiency improvements reduce CO2 and other emissions.

1.15. Page 104: Obstacles to Implementation of CO2 Emission Reduction Options". This section will be referenced in this report; e.g., "The obstacles to combustion, steam cycle and O&M upgrades in the APEC region should be low in the developed economies and likely somewhat higher in the developing economies in the APEC region.

1.16. Page 107: "The Scenarios to Reduce CO2 Emissions" section will be referenced in this report.

1.17. Page 108: E-4 is listed as the highest potential for reductions.

1.18. Appendix C: Data from APEC Countries will be incorporated in this report as applicable data.

1.19. Appendix D: Table D-1 provides efficiency improvements for various refurbishment and maintenance options. This information will be incorporated in this report.

1.20. Appendix E: Table E-1 shows the calculations for estimating CO2 reduction for the E-4 and other categories. This information will be incorporated in this report.

2. Options to Reduce CO_2 Emissions from Electricity Generation in the APEC Region (Phase II) HRL Technology Pty Ltd.

The summary of the report states:

> "The report takes a standard database of power station in the AEPCE region and identifies the types and capacities of power station plant in the APEC economies. It then identifies four basis categories (see below) and within these a total of nineteen CO_2 reduction scenarios. The CO_2 reduction that could be achieved in each scenario if a reasonable proportion of plants in each class were converted, irrespective of APEC economy or equipment manufacturer, is estimated. There are broad variations in the number and capacity of plants in each class and in the possible reduction for that class."
>
> "The four basic categories of options identified are as follows:
>
> - Combustion, steam cycle and O&M upgrades:
> - Co-firing and switching to lower carbon fuel;
> - Repowering with more efficient technology or biomass; and
> - Combined heat and power generation."

Of the above four categories, the first, Combustion, steam cycle and O&M upgrades, is applicable to this report. Information applicable to this report is summarized below.

2.1. Of the eleven Case Studies presented in the Phase II Report the studies for two existing pulverized-coal plants are applicable; Banshan and Liddel.

2.1.1 Banshan: This plant is located in Hangzhou, capital of Zhejiang province in PR China. This project included the following improvement for a 125-MW unit:

a. Turbine: included a complete upgrade.

b. Boiler improvements: including sootblowers, burner tilt mechanism improvements, reduction in excess air, furnace remodeling, pulverizer maintenance and air heater upgrading.

c. A complete control system upgrade.

d. For the above improvements, the following information was provided:

e. Capital costs are briefly stated.

f. Unit efficiency improvements are briefly stated.

g. Fuel cost savings are briefly stated.

h. CO_2 abatement cost is also shown.

i. A very brief summary of the costs and benefits is provided based on using an internal rate of return economic value to compare to the capital cost was provided:

Although this Phase II Report section is directly applicable to the Upgrading and Refurbishment Report the level of detail provided is insufficient for a comprehensive understanding of this major project. For example, the information provided does not describe the turbine or boiler efficiency improvements separately; only the overall plant efficiency improvement is provided. Also, the total capital cost was stated whereas the individual costs for the turbine, boiler and for other improvements is needed for this report. It is important that plant owners and operators to see the operational improvements and capital expenditures in sufficient detail to understand how they can justify and implement improvements on their plants.

2.1.2 Liddell: This plant is located in New South Wales, Australia. This project involved replacing the low pressure steam turbine blades resulting in a 3% efficiency improvement. The following information was provided for this improvement:

a. A brief summary of the costs and benefits is provided based on using an internal rate of return (IRR) economic value to compare to the invested capital cost.

b. Demonstration of how one typical impediment, i.e. capital cost justification was addressed. In this case, the Australian government provided supplemental project funding.

c. The justification shown may not be as strong as could be; e.g. there are only revenue increases based on increased electrical output. However, there should be reduction in ash disposal costs, pulverizer maintenance, reduced auxiliary power and other variable cost savings that are not included whereas they usually are for this type of improvement. Also, the reason for replacing the LP turbine section and not the high pressure (HP) turbine section should have been discussed because the HP section refurbishment usually provides the major improvement in turbine overall efficiency.

d. Section 5 (page 67) provides information for addressing impediments.

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