ABSTRACT

As concerns increase regarding the effect of anthropogenic emissions of CO$_2$ on global climate, efficiency improvement, as the only practical option capable of immediate reduction of CO$_2$ emissions, has become a key concept in choosing technology for new plants and upgrades of existing power plants. Early reduction in CO$_2$ emissions is of paramount importance, because the sooner we start reducing CO$_2$ emissions, the smaller the future reduction and the lower the cost to stabilize CO$_2$ concentration in the atmosphere at desired levels.

The main objective of this study is identification of cost-effective commercially-ready options, newly developed technologies and concepts, and technologies nearing commercial application for improving efficiency and reducing pollution control costs for existing coal-fired power plants using Illinois coals. The further objective is analysis of performance improvement options, and quantification of achievable performance improvements and emissions reductions. To accomplish project objectives, a comprehensive review and analysis of potential heat rate improvement and emissions reduction options was performed to quantify benefits and costs of each option. Options analyzed in this work included: recovery and utilization of heat from flue gas, improvements to the steam turbine cycle and heat rejection system, improved performance of boiler auxiliaries, improvements to combustion sensors and control, balancing of coal flow among individual burners, combustion optimization, sootblowing optimization, and repowering. The total potential improvement (excluding repowering), although not cumulative and being dependent on many site-specific factors, ranges from 3.5 to 12\% for bituminous coals, 6.4 to 12.5\% for washed Illinois coals, 7.3 to 13.8\% for PRB coals, and 9 to 16\% for lignites.

In conclusion, there are numerous options available for improving performance and reducing emissions from existing coal-fired power plants. Although potential improvements can be large, the actual improvement depends on many site-specific design, operating, and maintenance conditions, and on the fuel burned. The actual improvement in net unit heat rate has to be determined on a unit-by-unit basis. Higher efficiency will allow the existing fleet of coal-fired power plants to continue playing an important and “greener” role in power generation.
EXECUTIVE SUMMARY

Concentrations of greenhouse gases, such as carbon dioxide (CO₂), in the atmosphere have increased over the past century, and are considered as a most likely cause of a global temperature increase. In 2007, about 50% of the total electricity generation in the U.S. was generated by coal-fired power plants, which accounts for 83% of CO₂ emissions from the power sector and 33% of CO₂ emissions from all sectors. In the U.S. about 50% of the operating fossil fuel fleet, or about 350,000 MW, is coal-based. A significant part of that capacity is over 35 years old having average efficiency of 30% or lower (Energy Information Administration).

The major operating cost of a coal-fired power plant is fuel purchase. Given the higher heating value of coal (HHV), the flow rate of coal required to generate desired gross power output is directly proportional to generation efficiency. The efficiency is, therefore, a very important factor affecting plant economics. Besides lower fuel costs and improved plant economics, reduced fuel use results in lower emissions of NOₓ, SOₓ, mercury (Hg), particulate matter (PM), CO₂, and other pollutants. CO₂ emissions are directly proportional to unit heat rate, i.e., 1% improvement in heat rate results in 1% reduction in CO₂ emissions, regardless of the coal type or its rank.

As concerns increase regarding the effect of anthropogenic emissions of CO₂ on global climate, efficiency improvement, as the only practical option capable of immediate reduction of CO₂ emissions, has become a key concept in choosing technology for new plants, and upgrades of existing power plants. Early reduction in CO₂ emissions is of paramount importance, because the sooner we start reducing CO₂ emissions, the smaller the future reduction and the lower the cost to stabilize CO₂ concentration in the atmosphere at desired levels. Although new, more efficient power-generating technologies, and CO₂ removal technologies are nearing commercialization, significant market penetration will take some time. Estimates range from 2030 to 2050 and beyond. Improving efficiency of existing power plants, and newly build generation (approximately 140,000 MW by 2030) remains the first logical, inexpensive and necessary step. Also, efficiency of a coal-fired power plant will have a strong effect on the cost of carbon capture. With higher efficiency, the flow rate of flue gas that has to be treated will be lower, resulting in a smaller, less expensive carbon capture and sequestration (CCS) system, having smaller adverse effect on plant efficiency and capacity.

The efficiency improvement of existing power plants is of great importance for the Illinois coal mining industry, because at least 90% of the coal mined in Illinois (approximately 32.5 million short tones annually) is used by the electric utility industry for power generation.

The previous work of the author of this report (Sarunac, N. et al., 2006) has identified

---

1 In terms of greenhouse gas abatement, there is no total consensus as to what the CO₂ target should be.
2 Sarunac, N., H. Bilirgen, E. K. Levy, and J. W. Sale, “Opportunities for Improving Efficiency of Coal-
options for improving net unit heat rate and reducing emissions from existing coal-fired power plants. Although, the total heat rate improvement is not cumulative, the potential heat rate improvement for power plants firing high-rank coals is estimated at 5 to 13% (relative) and 6 to 15% (relative) for power plants firing high-moisture coals.

The main objective of this study is identification of cost-effective commercially-ready options, newly developed technologies and concepts, and technologies nearing commercial application for improving efficiency and reducing pollution control costs for existing coal-fired power plants using Illinois coals. The further project objective is analysis of performance improvement options and quantification of achievable performance improvements and emissions reductions. To accomplish project objectives, a comprehensive review and analysis of potential heat rate improvement and emissions reduction options was performed to quantify benefits and costs of each option. Options, analyzed in this work included: recovery and utilization of heat from flue gas, improvements to the steam turbine cycle and heat rejection system, improved performance of boiler auxiliaries, improvements to combustion sensors and control, balancing of coal flow among individual burners, combustion optimization, sootblowing optimization, and repowering. Improvements in net unit heat rate and reductions in CO₂ emissions, associated with investigated options are summarized in Table 1. The total potential improvement, although not cumulative and being dependent on many site-specific factors ranges, from 3.5 to 12% for bituminous coals, 6.4 to 12.5% for washed Illinois coals, 7.3 to 13.8% for PRB coals, and 9 to 16% for lignites.

Some of the investigated options involve application of advanced technologies, such as the heat recovery and utilization from flue gas option. The amount of heat in the flue gas is simply too large to be discharged into the atmosphere. Recovered heat can be used for air preheating, feedwater heating, reduction of moisture content for high-moisture coals, and stack reheat. A flue gas cooler (FGC) is enabling technology, commercially available from several vendors, for recovering heat from the flue gas. The cost ranges from $0.06 to $0.13 per Btu of recovered heat, depending on choice of corrosion-resistant materials. Improvements to the steam turbine cycle involve application of high-efficiency turbine blade design, application of better seals, improvement or replacement of feedwater heaters, and improved exhaust hood design. Although the cost of turbine upgrades could be in the $30 million range (depending on the turbine size and extent of the upgrade), and the cost of the individual feedwater heater (FWH) could be in the $5 million range, these improvements not only improve efficiency, but also increase unit capacity. This capacity increase represents fuel-free or “green” megawatts, because no additional fuel is used. Although improvements to the heat rejection system can provide performance improvements similar in magnitude to turbine cycle improvements, these can be, in most cases, achieved by monitoring of condenser and cooling tower performance, and proactive and timely maintenance practices. Also, performance of a cooling tower can be improved by use of new, more efficient fill designs. Variable

frequency drives should be considered for circulating water pumps and fans on mechanical draft towers to reduce auxiliary power use.

### Table 1: Potential Performance Improvement Options for Existing Power Plants

<table>
<thead>
<tr>
<th>Performance Improvement Method/Option</th>
<th>Min</th>
<th>Max</th>
<th>Coal</th>
<th>Comment</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reduction of Heat from Flue Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FGC for Feedwater (FW) Heating</td>
<td>1.39</td>
<td>1.46</td>
<td>Bituminous</td>
<td>FGC commercially available</td>
<td>$0.06 to $0.13 per Btu recovered heat</td>
</tr>
<tr>
<td>FGC for Advanced Air Preheating</td>
<td>1.34</td>
<td>1.33</td>
<td>Bituminous</td>
<td>FGC commercially available</td>
<td>$0.06 to $0.13 per Btu recovered heat</td>
</tr>
<tr>
<td>FGC for PHE Heating + Air Preheating</td>
<td>1.32</td>
<td>1.33</td>
<td>Washed Bituminous</td>
<td>FGC commercially available</td>
<td>$0.06 to $0.13 per Btu recovered heat</td>
</tr>
<tr>
<td>FGC and UFG for PHE Heating</td>
<td>1.20</td>
<td>1.20</td>
<td>Bituminous</td>
<td>Post-Combustion CCS</td>
<td></td>
</tr>
<tr>
<td>FGC and UFG for Air Preheating</td>
<td>1.34</td>
<td>1.34</td>
<td>Washed Bituminous</td>
<td>Post-Combustion CCS</td>
<td></td>
</tr>
<tr>
<td><strong>Seal Replacement</strong></td>
<td>0.16</td>
<td>0.16</td>
<td>Bituminous</td>
<td>Depending on seal choice</td>
<td></td>
</tr>
<tr>
<td><strong>Flue Gas Temperature Leaving the APH</strong></td>
<td>1.00</td>
<td>1.00</td>
<td>Bituminous</td>
<td>For 1°F change in stack temperature</td>
<td></td>
</tr>
<tr>
<td><strong>Converter to Leakless AHI</strong></td>
<td>0.15</td>
<td>0.15</td>
<td>Bituminous</td>
<td>For 1°F change from initial water temp</td>
<td></td>
</tr>
<tr>
<td><strong>APH Fouling and Plugging</strong></td>
<td>0.05</td>
<td>0.05</td>
<td>All Coals</td>
<td>Depending on hood geometry</td>
<td></td>
</tr>
<tr>
<td><strong>Flue Gas Reheat by Heat Displacement</strong></td>
<td>2.45</td>
<td>2.45</td>
<td>Bituminous</td>
<td>For 1°F change in reheat steam temp</td>
<td></td>
</tr>
<tr>
<td><strong>Heat Rate Improvement</strong></td>
<td>0.02</td>
<td>0.02</td>
<td>Washed Illinois</td>
<td>For 1% increase in air temp</td>
<td></td>
</tr>
</tbody>
</table>

Air preheater (APH) performance is also very important for maintaining high plant performance and availability. APH leakage, corrosion, and plugging caused by deposition of sulfuric acid and ammonium bisulfate (ABS) increase auxiliary power use, can result in load derate, and can compromise unit availability if APH water-washing is needed. New, high-efficiency seals can reduce APH leakage by a factor of two, while advanced air preheating can be used to reduce corrosion and fouling and simultaneously
improve unit performance. Auxiliary power use can be decreased by installing VFDs on main fans and other large electrical motors. Improvements to combustion sensors and control, including tuning and control system upgrades can result in large performance improvements, especially on older units and units retrofitted with low-NOx firing systems. Balancing of coal flow between coal pipes improves performance and reduces emissions by allowing operation at lower excess O₂ and higher combustion efficiency, and achieves more stable boiler operation. Combustion optimization represents a cost-effective approach for reducing emissions and optimizing performance of existing combustion and pollution control equipment. Sootblowing optimization can solve many problems related to slagging and fouling, poor steam temperature control, opacity exceedances, and related capacity and performance losses. Repowering offers a wide range of options, from Rankine-Brayton to solid fuel-based repowering. With Rankine-Brayton repowering, a combustion turbine is incorporated into an existing coal-fired power plant to improve its performance and increase capacity. The main benefits include higher efficiency and capacity and lower CO₂ emissions. Lower CO₂ emissions are achieved due to higher efficiency and firing of less carbon-intensive fuel (natural gas). The solid fuel-based repowering options include application of fluidized bed technology (bubbling or circulating bed), either at atmospheric or elevated pressure, fluidized bed gasification, and Integrated Gasification Combined Cycle (IGCC). Application of these repowering options improves plant net unit heat rate by up to 30% while allowing use of low-cost opportunity fuels. In addition, oxygen-blown IGCC is very suitable for implementation of carbon capture and sequestration (CCS) technology. The choice of repowering technology depends on the required reduction in CO₂ emissions from existing units, CCS costs, and price of CO₂ emission credits or carbon tax.

The options for reducing CO₂ emissions analyzed in this project included: biomass co-utilization, post-combustion CO₂ capture, and oxy-fuel combustion. Negative effects of biomass co-firing can be eliminated by thermal drying of wet biomass. Thermal integration and heat recovery will help reduce negative effects of post-combustion CO₂ capture, and oxy-fuel combustion.

To illustrate the effect of potential performance improving measures, two power stations firing Illinois coals were visited to inspect their units, identify hardware improvements, and collect plant operating data. Plant operating data were analyzed to determine effects of scheduled outages, hardware upgrades, and identify options for additional improvements. Recommendations for further improvements were provided for each power station.

In summary, there are numerous options available for improving performance and reducing emissions from existing coal-fired power plants. Although potential improvements are large, the actual improvement depends on many site-specific design, operating, and maintenance conditions, and on the fuel burned. The actual improvement in net unit heat rate has to be determined on a unit-by-unit basis. Higher efficiency will allow the existing fleet of coal-fired power plants to continue playing an important and “greener” role in power generation.
OBJECTIVES

The main project objective is identification of cost-effective commercially-ready options, newly developed technologies and concepts, and technologies nearing commercial application for improving efficiency and reducing pollution control costs for existing coal-fired power plants using Illinois coals. The further project objective is analysis of identified performance improvement options and quantification of achievable performance improvements and emissions reductions. More specifically, the project goals included:

- Improve efficiency and reduce emissions of existing power plants firing Illinois coal.
- Identify practical cost-effective options for efficiency improvement and reduction of environmental compliance cost. Quantify efficiency improvement and cost for each of the selected performance improvement options.
- Quantify emissions reductions and cost for each of the selected performance reduction options.
- Develop and apply methodology and analysis tools for determining effects of identified performance improvement and emission reduction techniques.
- Analyze performance and emissions improvements achieved by planned outages and hardware upgrades for two selected power plants of different vintage, size, and design firing Illinois coal.

To best accomplish project objectives, the work was divided into the following tasks:

Task 1: Identify and Characterize Cost-Effective Options for Efficiency Improvement
Task 2: Identify and Characterize Cost-Effective Options for Emissions Reduction
Task 3: Develop Analysis Methodology and Tools
Task 4: Analyze Effect of Planned Outages and Hardware Upgrades on Performance and Emissions and Recommend Options for Further Improvements for Two Power Plants Firing Illinois Coals

To accomplish these objectives, an analysis methodology and software tools were developed. Also, existing methods of analysis and software tools were used.

INTRODUCTION AND BACKGROUND

Concentration of greenhouse gases, such as CO₂, in the atmosphere has increased over the past century, and is considered as a most likely cause of a global temperature increase. In 2007, about 50% of total electricity generation in the U.S. was generated by coal-fired power plants, which accounts for 83% of the carbon dioxide (CO₂) emissions
from the power sector, and 33% of the CO₂ emissions from all sectors (residential, commercial, industrial, transportation, and power generation). Worldwide, the percentage of electricity generated from coal is higher. According to Energy Information Administration (IEA) and International Energy Agency (IEA) predictions, the use of coal will continue to increase, and it is projected that CO₂ emissions from the power generation sector will increase to 38% of total CO₂ emissions (which are projected to increase by 16% from the 2006 level).

In the U.S. about 50% of the operating fossil fuel fleet, or about 350,000 MW, is coal-based. A significant part of that capacity is over 35 years old and requires modernization. These older coal-fired power plants (units) have an average efficiency of 30% or lower.

A relationship between the net unit efficiency and net unit heat rate (HR\textsubscript{net}) is presented in Figure 1. Thermal efficiency, or efficiency (\(\eta\)), is defined as the electric energy output as a fraction (or percentage) of the fuel energy input. Heat rate is an inverse of efficiency (multiplied by the unit conversion factor of 3,412). The net unit heat rate, HR\textsubscript{net}, is defined as:

\[
HR\textsubscript{net} = \frac{Q_{\text{fuel}}}{P_{\text{net}}} = \frac{M_{\text{coal}} \cdot \text{HHV}}{(P_G - P_{\text{ss}})} \tag{Eqn. 1}
\]

where \(Q_{\text{fuel}}\) is heat input with fuel, \(P_{\text{net}}\) is net unit power output, \(M_{\text{coal}}\) is flow rate of coal fired to generate gross power output \(P_G\), HHV is coal higher heating value, and \(P_{\text{ss}}\) is station service (auxiliary power) use.

![Figure 1: Unit Efficiency vs. Heat Rate](image)
References are often made in the literature to changes in efficiency by percentage points (%-points), which should be distinguished from relative changes in percentage. For example (see Figure 1), a change of 1%-point in efficiency (from 36 to 37%) represents a relative change of 2.7%.

Both efficiency and heat rate can be expressed on a HHV- or LHV-basis. In the U.S., HHV is used for coal-fired power plants, while in the Europe, efficiency calculations are based on LHV*. The difference in efficiency between HHV and LHV for bituminous coal is about 2%-points (5% relative), while for high-moisture sub-bituminous coals and lignites, the difference is about 3-4%-points (8 to 10% relative), depending on the coal composition.

The major operating cost of a coal-fired power plant is fuel (coal) purchase. Given the HHV, the flow rate of coal required to generate desired gross power output depends on unit efficiency. The efficiency is, therefore, a very important factor affecting plant economics. Besides lower fuel costs and improved plant economics, reduced fuel use results in lower emissions of NOx, SOx, Hg, particulate matter (PM), CO2, and other pollutants. A relationship between heat rate improvement and reduction in CO2 emissions, presented in Figure 2, shows that CO2 reduction is directly proportional to heat rate improvement, i.e., 1% improvement in heat rate results in 1% reduction in CO2 emissions, regardless of the coal type or its rank.

![Figure 2: Reduction in CO2 Emissions vs. Improvement in Net Unit Heat Rate](image)

* LHV is usually used in analysis of gas turbine cycles, both in the U.S. and in Europe. As an exception, HHV is often used for IGCC plants in the U.S. to allow consistent comparison with other coal-based technologies.
As concerns about the effect of anthropogenic emissions of CO₂ on global climate increase, efficiency improvement, as the only practical option capable of immediate reduction of CO₂ emissions, has become a key concept for the choice of technology for new plants, and upgrades of existing power plants. Early reduction in CO₂ emissions is of paramount importance, because the sooner we start reducing CO₂ emissions, the smaller the future reduction and lower cost to stabilize CO₂ concentration in the atmosphere at desired level.

Post-combustion CO₂ capture, oxy-fuel combustion, and other CO₂ capture methods are the subject of intensive research and development. Significant advancements were made in demonstration with the first mid-size, 30 MW_{th}, oxy-fuel pilot plant in operation at Schwarze Pumpe, Germany since October 2008, and the first commercial-size amine-based CO₂ scrubbing system in operation at a power plant owned by E.ON in Rotterdam since 2008. Work on reduction of negative effects of carbon capture and sequestration (CCS) on plant efficiency and capacity continues. These CCS techniques nearing commercialization stage are still far away from achieving any significant market penetration. A study made by a council of electric utilities in Europe has concluded if CCS technology at its current state of development were implemented fleet-wide, the consumption of coal would have to be increased by 25% to maintain the same capacity. Similar conclusions were obtained in numerous studies conducted in the U.S.

Given the state of development of CCS technologies, and projected significant market penetration 30 to 50 years from now, the most effective, logical, and immediate approach for reducing CO₂ emissions is to increase generation efficiency from existing coal-fired plants and new generation (approximately 140,000 MW) to be built by 2030, as well as to promote end-use efficiency. If heat rate of the existing generating fleet were increased by 5%, coal consumption will be reduced by 5%, resulting in 5% reduction in CO₂ emissions; equivalent to approximately 17,500 MW of coal-fired generation. Therefore, efforts aimed at increased energy efficiency, both at the generation and end-use sides are central to any economic CO₂ emissions strategy.

To illustrate the importance of unit performance improvement, savings in fuel and CO₂ emissions costs for a 580 MW power plant firing Illinois coal (Crown 2) are presented in Figure 3 as functions of the improvement in net heat rate and cost per ton of CO₂.

Results show that 1% improvement in net unit heat rate (on a relative basis) with energy cost of $4/MBtu and unit capacity factor of 0.85 results in annual fuel savings of $1.6 million. Assuming a CO₂ cost of $30 per ton (a conservative estimate), annual savings are almost doubled ($2.8 Million/year).

Also, efficiency of a coal-fired power plant will have a strong effect on the cost of carbon capture and sequestration (CCS). With higher efficiency, the flow rate of flue gas that needs to be treated will be lower, resulting in a smaller and less expensive CCS system. A smaller CCS will also have smaller adverse effect on plant efficiency and capacity.
There are numerous opportunities and options for improving efficiency of existing power plants. The definition of net unit heat rate, expressed in terms of boiler efficiency ($\eta_B$), turbine cycle heat rate ($HR_{cycle}$), station service (auxiliary power) use ($P_{ss}$), and gross power output ($P_G$), shown in Figure 4, provides a roadmap to heat rate improvement options; the net unit heat rate can be improved by improving boiler efficiency, improving turbine cycle heat rate, and reducing auxiliary power use.

**Figure 3**: Annual Savings in Fuel and CO₂ Emissions Cost vs. Improvement in Net Unit Heat Rate

**Figure 4**: Options for Heat Rate Improvement
The efficiency improvement of existing power plants is of great importance for the Illinois coal mining industry because at least 90% of the coal mined in Illinois (approximately 32.5 million short tons annually) is used by the electric utility industry for power generation.

Looming on the horizon are regulations requiring a significant reduction in CO₂ emissions. Although the magnitude of required CO₂ emissions, compliance options and the regulatory timeline are presently unknown it is certain that any mandatory reduction in CO₂ emissions from existing power plants will have a major impact on the cost of electricity. Early reduction in CO₂ emissions from existing power plants is, as stated before, of utmost importance.

The previous work of the author (Sarunac, N. et al., 2006) has identified options for improving net unit heat rate and reducing emissions from existing power plants and has estimated magnitude of potential improvements. Although, the total improvement may not be cumulative, the potential total improvement was significant: approximately 5 to 13% (relative) for power plants firing high-rank coals, and 6 to 15% (relative) for power plants firing high-moisture coals.

EXPERIMENTAL PROCEDURES (TECHNICAL APPROACH)

General Approach
Thermodynamic analysis of commercially available heat rate improvement technology options, technologies nearing commercialization stage, and newly developed technologies and concepts for efficiency improvement and emissions reduction of older coal-fired power plants, firing Illinois coals, was conducted. An analysis methodology and analytical models for modeling of power plant performance and performance of its components were developed to evaluate various technology options, and determine their effect on power plant efficiency and emissions.

Also, plant operating data was collected at two power generation sites (three power plants firing Illinois coals) using Plant Information (PI) system over a period of two months preceding scheduled unit outages, and two months following each outage. Regular power plant maintenance was performed during the outage at one of the selected plants, while equipment upgrades were performed at the other two power plants in addition to the regular maintenance. Equipment upgrades involved upgrades to the boiler and auxiliaries (fans, mills, and APHs), steam turbine cycle (high pressure and intermediate pressure turbine, turbine seals, and last stage blades), feedwater heater replacement, condenser retubing, and upgrades to the pollution control system ranging from installation of larger electrostatic precipitator (ESP), forced oxidation upgrade to the existing wet scrubber, and installation of a new wet scrubber. Operating data was analyzed to determine effects of scheduled outages and hardware upgrades on performance and emissions. Based on results of the analysis, and information collected during the site visit and field inspection, recommendations for further improvements were provided for each power generation site.
Analysis Methodology and Modeling
To accomplish project objectives, a spreadsheet-based first principles analysis based on conservation of mass and energy and equilibrium thermodynamics was developed. The analysis also included combustion calculations, heat transfer analysis, calculation of fan and mill power, and equilibrium-based condensation of sulfuric acid and moisture from the flue gas. This analysis approach was used because it offers flexibility and freedom in modeling, complete understanding of employed analytical models and modeling assumptions, and also allows building models of unconventional system configurations. Model results and predictions were, wherever possible, compared and verified against test or plant operating data, or results from the literature.

A spreadsheet model of a regenerative Rankine steam turbine cycle was developed to allow modeling of heat recovery from the flue gas and its use for feedwater heating and air preheating (advanced air preheating), and evaluation of tradeoffs and different options. Although, modeling of the steam turbine cycle can also be conducted by using commercial codes such as PEPSE and Aspen Plus, the spreadsheet-based modeling allows ultimate flexibility when analyzing unconventional system configurations. The model results were verified against design and performance test data and results from the literature. Spreadsheet models were developed to allow modeling of the entire power plant, modeling of the regenerative steam turbine cycle, and modeling of heat recovery (sensible and latent heat) from the flue gas. Results obtained from heat recovery models were verified against design data received from manufacturers of flue gas coolers (German Babcock Borsig Services and Swiss Flucorex).

Also, existing analytical models, developed by the ERC, were used in the analysis. These included HEATRT, RPHMT, and the FBD codes. HEATRT (Sarunac et al., 1985) is a first principles model of a power plant, developed by the ERC for EPRI, allowing modeling of a wide variety of conventional power plant configurations. The model performs combustion analysis, mass and energy balance, and heat transfer analysis to determine net unit heat rate, boiler efficiency, and flow rates of air and flue gas at a number of state points throughout the power plant. The HEATRT code was verified against field and test data in previous EPRI studies. The code was used extensively in this project to determine the effect of operating conditions such as excess oxygen (O₂) level, unburned carbon in ash (expressed as LOI), APH performance, flue gas temperature, steam temperature, fuel quality, and other parameters on unit performance.

RPHMT (Sarunac, 1985) is a finite-difference model of the regenerative APH, developed by the ERC for EPRI. The code allows modeling of the Ljungstrom- and Rothemuhle-type of regenerative heat exchangers. Both the bi-sector and tri-sector APH configurations can be modeled. RPHMT employs mass and energy balance and heat transfer analysis to determine thermal performance of the APH, and temperatures of heat transfer surfaces, combustion air, and flue gas throughout the heat transfer matrix. The code has been verified against field measurements in previous EPRI studies. The RPHM was used for prediction of the effects of plant and APH operating conditions on thermal performance of the APH, temperature of the heat transfer matrix, and onset of sulfuric acid and ammonium bisulfate deposition, and size and location of deposition zones.
FBD (Levy et al., 2006) is a first principles drying model predicting performance of a fluidized bed dryer (FBD). The code uses coal-specific information relating relative humidity of drying air in equilibrium with coal as a function of coal moisture content and temperature. The code is verified against test data used to develop the relative humidity vs. coal moisture relationship, and has been used to predict performance of a FBD as a function of its operating conditions.

RESULTS AND DISCUSSION

Task 1: Identify and Characterize Cost-Effective Options for Efficiency Improvement

Efficiency-improving technologies analyzed in Task 1 included: recovery and utilization of heat from flue gas, improvements to the steam turbine cycle, improvements to the heat rejection system, improved performance of boiler auxiliaries, improvements to combustion sensors and control, coal flow balancing in PC-fired boilers, combustion optimization, sootblowing optimization, and repowering. Descriptions of each option and their effects on plant performance and emissions are summarized in this section. Details are presented in Appendices I to IX.

Recovery and Utilization of Heat from Flue Gas

The temperature of flue gas leaving the boiler is commonly reduced in an APH, where sensible heat in flue gas leaving the economizer is used to preheat combustion air. Common practice is to recover sensible heat from flue gas until its temperature drops to approximately 300°F. The primary impediment to recovering heat by additional cooling is the risk of sulfuric acid condensation on the APH heat transfer surfaces and downstream ductwork. Upon exiting the electrostatic precipitator (ESP), the flue gas temperature is decreased by evaporative cooling in a spray area of a wet FGD to a temperature close to the adiabatic saturation temperature. This practice results in significant use of water for evaporative cooling. More importantly, the sensible heat of flue gas is not beneficially used.

The total (sensible and latent) heat of the flue gas stream leaving the ESP is large. As the flue gas is cooled below water dewpoint, flue gas moisture condenses, liberating latent heat, and the amount of total heat greatly increases. However, there are practical limitations associated with cooling of the flue gas to low temperatures and use of the low-temperature heat. Despite these limitations, the amount of heat in the flue gas is simply too large to be discharged into the atmosphere or quenched by sprays. Use of heat recovered from the flue gas for performance improvement and emissions reduction was analyzed in this project.
Feedwater Heating and Advanced Air Preheat

System configurations for using low-temperature heat from the flue gas, analyzed in this project, included a configuration for feedwater (FW) heating and preheating of combustion air presented in Figure 5. The low-temperature heat is recovered from the flue gas using a flue gas cooler (FGC) located upstream of the FGD, and used for the FW heating and/or air preheating. To quantify benefits of using heat recovered from the flue gas for FW heating and air preheating, an analysis was performed for the system configuration presented in Figure 5 and four coals: bituminous, washed Illinois, PRB, and lignite. Results are summarized in Figure 6 as a relative improvement in net unit heat rate with respect to the baseline configuration with no heat recovery.

**Figure 5:** Low-Temperature Heat Recovery for FW Heating and Combustion Air Preheat

**Figure 6:** Improvement in Net Unit Heat Rate as Function of Heat Use and Coal Type
The improvement in net unit heat rate depends on the use of recovered heat and coal type. For the system configuration employing FW heating and air preheating, the relative improvement in net unit heat rate varies from 1.3 to 2.4%, and is largest when recovered heat is used for FW heating and air preheating. The analysis was performed by assuming the same degree of air preheat in all cases. The effect of air preheat temperature on performance is presented in Appendix IV. The performance improvements for system configurations employing condensing heat exchangers to recover latent heat are higher (up to 3.6%). These configurations and predicted performance improvements are presented in Appendix I.

In summary, performance improvements achievable by using heat recovered from the flue gas for the FW heating and combustion air preheat can be significant and should be considered as measures for improving performance and reducing emissions for existing and newly constructed power plants. For existing power plants where it is difficult or impossible to raise steam parameters to improve performance, use of heat recovered from the flue gas represents an attractive option.

**Reduction of Coal Moisture Content by Thermal Drying**

When coals with high-moisture content are burned in a utility boiler, several percent of the fuel heat input is used to evaporate fuel moisture. This results in higher flow rates of coal compared to low-moisture coals, higher flow rates of the flue gas and combustion air, higher fan and mill power requirements, and lower unit efficiency. Some Illinois basin coals are washed to remove impurities such as ash and sulfur, reduce potential emissions, improve HHV, and increase value. Washed coals contain significant amounts of water (mostly as surface moisture) and need to be dewatered to improve handling and heating value and dried to further improve HHV. Dewatering of coal is accomplished by using conventional equipment. Further reduction of coal moisture content can be accomplished by thermal drying.

A low-temperature coal drying process employing a fluidized bed dryer (FBD) and waste heat was developed by a team led by Great River Energy (GRE) and Lehigh University’s Energy Research Center (ERC). The FBD is fluidized by air preheated to a desired temperature. Additional heat is supplied to the dryer by using an in-bed heat exchanger.

Reduction of coal moisture content by drying increases HHV of the coal. For a constant power output, higher HHV results in lower coal flow rate and reduced burden on the plant coal handling system including mills and feeders. Lower flow rate and improved grindability of dried coal result in lower mill power. Also, flow rates of combustion air and flue gas decrease as the moisture content of coal and coal flow rate are reduced. A 15%-point reduction in coal moisture content will result in a reduction in flue gas flow rate of 6% for lignite and 2 to 3.5% for washed Crown coal, depending on configuration of the coal drying system. Reduced flue gas flow rate will have a positive effect on performance of the existing pollution control system (increased residence time), as well as on the size and capital and operating costs of a post-combustion CO₂ capture system.
The effect of coal moisture content on relative improvement in net unit heat rate is presented in Figure 7 for lignite, PRB, and Crown 2 coals. Results are presented for three configurations labeled as HTC, BC, and LTC. The HTC (High-Temperature) configuration uses high-grade (high-temperature) heat recovered from the flue gas as a source of heat for drying. Mid-grade heat is used in the base case (BC) configuration, while low-grade heat is used in the LTC (Low-Temperature) configuration. The magnitude of improvement depends on configuration of the coal drying system, and increases as temperature of the heat source decreases. A 15%-point reduction in coal moisture content will result in a relative improvement in net unit heat rate of 3 to 6% for lignite, 2 to 3.5% for PRB coal, and 0.8 to 2% for Crown coal, (Sarunac et al. 2008).

![Figure 7: Improvement in Net Unit Heat Rate as Function of Coal Moisture Content and Drying System Configuration for Lignite, PRB, and Illinois (Crown 2) Coals](image)

Thermodynamic maximum represents the case where coal is dried at another facility (off-site) and is delivered to the plant with reduced moisture content. It represents maximum improvement that could be achieved with dried coal, because losses associated with coal drying such as fan power requirements for the fluidizing air are avoided.

In summary, performance improvements that can be achieved by coal drying can be significant and should be considered as cost-effective measures for improving performance and reducing emissions for existing and newly constructed power plants firing high-moisture coals. Utilization of low-temperature heat recovered from the flue gas makes the coal drying process especially attractive. With the retrofit cost in the $50/kW to $100/kW range, savings in fuel and emissions control costs (excluding CO₂) yield a return on investment (ROI) of less than three years.
**Flue Gas Reheat by Heat Displacement**

The flue gas is leaving the wet FGD in a saturated or supersaturated state, carrying a significant amount of moisture, some in the form of water droplets. Although most water droplets are removed in a demister, some pass through the chevron vanes.

Reheat of saturated flue gas is needed if velocities in the stack exceed critical velocity, which allows water droplets to be carried into the atmosphere with the flue gas, or to increase buoyancy of the flue gas to insure adequate dispersion of residual SO₂, NOₓ, and particulate matter (PM) exiting from the stack. The flue gas re heater can be integrated with the FGD. Heat for the reheater is commonly supplied by low-pressure steam extracted from the steam turbine. This steam extraction reduces the steam turbine output by approximately 1% (depending on coal moisture content and ambient conditions), and decreases plant efficiency.

The heat displacement technology makes use of heat recovered from the flue gas in a FGC upstream of the FGD for reheating the saturated flue gas leaving the FGD. The use of extraction steam is eliminated, resulting in higher steam turbine cycle output, and improved unit performance. Schematic representation of several heat displacement concepts and results of the analysis, are presented in Appendix I. For washed Illinois coal, the relative heat rate improvement achieved by using heat displacement for reheating the flue gas from the saturation temperature to 160°F is approximately 0.6%.

**Flue Gas Coolers**

A flue gas cooler (FGC) is an important piece of equipment enabling recovery of heat from the flue gas. Since a significant section of the FGC operates below the acid dewpoint temperature, the heat transfer surface has to be constructed from corrosion-resistant materials, such as corrosion-resistant alloys, carbon steel with corrosion-resistant coating, high-temperature corrosion-resistant plastic tubing, or borosilicate glass. Details concerning materials and design are presented in Appendix I.

Use of corrosion-resistant plastic or alloy tubes increases the cost of a FGC. As a rule of thumb, the cost of a FGC operating below acid dewpoint is about ten times higher compared to the finned tube design employing carbon steels. The cost of a FGC depends on the choice of material and ranges from $0.06 per Btu/hr of recovered heat for enamel glass lined steel, to $0.10-0.13 per Btu/hr of recovered heat for corrosion-resistant alloys.

**Improvements to the Steam Turbine Cycle**

Over its lifetime, a steam turbine can lose from 2 to 5% of its efficiency with the amount of efficiency loss depending on the number of hours of operation and the quality of maintenance. In today’s highly competitive electricity generating market, there are both financial and environmental incentives to improve generation efficiencies. The same technology advances that are incorporated into new steam turbines can be used to improve the performance of existing turbines. Upgrading existing turbines can raise efficiencies by as much as 5% in high-pressure (HP) turbines, 4% in intermediate-pressure (IP) turbines, and 2-1/2% in low-pressure (LP) turbines. Also, turbine upgrade can result in a significant increase in turbine output. Details are presented in Appendix II.
Steam turbine technologies that are available for modernization of existing units and were investigated in this study include: rotors and casings, partial to full-arc admission retrofits, high-efficiency turbine blades, new blade materials, improved inter-stage seals, advanced L-0 blades, LP turbine exhaust hood improvements, generator cooling, and improvements to feedwater heaters (FWHs). These improvements can, cumulatively, increase turbine cycle heat rate by 2 to 4.5% (relative), which will improve net unit heat rate. Also, as presented in Figure 2 the reduction in CO₂ emissions is directly proportional to the net unit heat rate improvement.

The largest single improvement that can be made to an existing steam turbine-generator is replacing the rotor and casing. New, more efficient steam turbine designs have been developed with higher-reaction lower-pitch diameters, longer blades, and increased annulus areas. Three-dimensional computational fluid dynamic (CFD) analysis was used to optimize the steam turbine blade design, in particular to reduce flow-through velocity (resulting in lower profile losses), improve blade aspect ratio (resulting in reduced secondary losses), and improved rotor-dynamics (producing lower velocities that allow smaller pitch diameters). A new rotor and casing provides all the individual component upgrades, such as improved blade design and materials, increased number of stages, decreased root diameter, increased active blade height, better seals, and improved LP exhaust end design. When retrofitting a steam turbine, the old internal stationary components are removed and replaced with a single, fully-integrated casing. The integral design also reduces thermal distortions during operation, which allows smaller clearances and improved unit efficiency.

At full load, there is little efficiency difference between full-arc and partial-arc admission. However, below full load, full-arc emission has a higher efficiency loss. Most modern controls start with full-arc allowing even heat distribution around the circumference of nozzle blocks and uniform warming of control valves. Once the turbine is under load and near rated inlet steam conditions, the control is shifted to partial-arc to avoid unnecessary throttle pressure losses across turbine control valves. This control mode improves turbine cycle heat rate over a wide range of turbine loads.

One often overlooked performance area in a steam turbine involves improvements in seal design. However, when considering a seal design, the specific operation of the steam turbine needs to be considered. Each application requires an evaluation to determine the best solution. There are four factors that need to be taken into consideration: installation, cost, durability, and performance. For example, replacing straight seals with brush seals in the HP and IP sections of a steam turbine can result in performance gain of about 0.74% as compared to 0.15 and 0.25% increases with dimpled seals and slant tip seals, respectively. On another unit, replacing retractable seals with Turbo seals has resulted in a 1.5% increase in net unit heat rate.

The low pressure (LP) turbine end blade is one of the most important elements in designing a steam turbine. This blade design determines the performance, dimensions, and number of casings of the turbine. Newly developed blade designs are applicable not only for new steam turbines but also for retrofitting existing steam turbines. Changes to
the LP blade design include increased blade length (lower annulus loss) and improved blade design with a free-standing last row blade. Also, improvements to the LP exhaust hood design have been developed to reduce pressure losses due to flow recirculation and detachment, reduce exit static pressure at the last stage rotating blades and increase LP power output, and improve condenser performance due to more uniform steam flow distribution.

Proper cooling is critical to generator performance and maximum generation capacity. Large generators are cooled with hydrogen because of its superior thermal properties. Generator losses can be decreased by increasing hydrogen pressure and maintaining high hydrogen purity. At increased pressure, hydrogen becomes denser, improving its heat transfer capacity and allowing the generator to carry additional electrical load without an increase in winding temperature. Hydrogen purity is important for safety and economic concerns. An explosive atmosphere exists if the hydrogen/air concentration drops below 74%. Furthermore, an increase in hydrogen purity will decrease generator windage loss. For example, a 3% increase in hydrogen purity in an 800 MW generator corresponds to about a 1 MW increase in generator output without any increase in fuel use. Therefore, a continuous supply of stable high-pressure high-purity hydrogen is critical to the efficient operation of a hydrogen-cooled generator.

Feedwater heaters transfer heat from steam extracted from the steam turbine to the feedwater to improve efficiency of the steam turbine cycle (by reducing heat loss in the condenser) and boiler efficiency (by reducing required heat input to steam). However, steam extractions reduce turbine power output, and FWH-related losses or failures adversely affect performance and can also affect capacity. Also, the final feedwater temperature is a function of the performance of the top high-pressure FWH. The ability to adjust the final feedwater temperature allows the turbine cycle to be optimized for either gross power output or efficiency.

Retrofitting FWHs with improved designs incorporating new technologies and materials will help protect the steam generator and help improve and maintain performance of the turbine and the unit. FWH modifications or retrofits should be considered when retrofitting steam turbines due to potential changes in extraction pressures and flows.

Improvements to the Heat Rejection System
Approximately 50% of the fuel heat input to a subcritical coal-fired power plant is rejected to the ambient (heat sink) by the cooling water system (assuming turbine cycle heat rate of 8,000 Btu/kWh and boiler efficiency in the 85 to 90% range). The amount of rejected heat decreases as efficiency of the steam turbine cycle increases. The rejected heat represents latent heat from condensing the LP turbine steam exhaust flow in the main steam condenser. This phase change is necessary to increase density of the working fluid and reduce compression work required to increase pressure of the condensate to the boiler inlet pressure. The latent heat of condensation is rejected to the environment by once-through cooling water system where bodies of water are used as a heat sink, or by cooling towers where heat is rejected directly to the atmosphere. Regardless of the
approach, condenser pressure has a major effect on performance of the steam turbine cycle.

The main condenser pressure is determined by the outlet cooling water temperature, which depends on the inlet cooling water temperature and cooling water temperature rise across the condenser. The condenser pressure is based on the saturation temperature of the condensing steam (the sum of the outlet cooling water temperature and the thermal temperature difference, TTD) plus partial pressure of non-condensables (in-leakage air). Because the inlet cooling water temperature is a function of ambient conditions, condenser pressure and turbine cycle performance change as ambient conditions change.

Maintaining the lowest main condenser pressure provides the best steam turbine cycle efficiency. While changes in ambient conditions are beyond the control of the plant operator, plant operating and maintenance practices have a significant effect on cooling water temperature rise across the condenser, TTD, and partial pressure of non-condensables. Improvements can be achieved by using good maintenance and operating practices on both the steam-side and the water-side of the main condenser, e.g. by maintaining cooling water flow, maintaining condenser cleanliness (which is affected by formation of scales, biofouling, and siltation), replacing plugged condenser tubes, and maintaining performance and capacity of the venting system (steam ejectors and vacuum pumps). Details are provided in Appendix III.

Unfortunately condenser performance is often an overlooked area for improving plant performance and increasing the profitability of the power plant. For full load operation, decreases in turbine cycle heat rate of more than 2% are typical for an increase in exhaust pressure of 2”Hg Abs. above design. It is not uncommon to find units operating with turbine back pressures approaching 5”Hg, which results in even larger heat rate penalties. Monitoring of condenser pressure and cleanliness should be implemented as a first step in a condenser performance improvement program.

In cooling tower systems, the main condenser pressure is also a function of ambient conditions (relative humidity and temperature of ambient air) and performance of cooling tower heat transfer surfaces (cooling tower fill), which affect the inlet cooling water temperature. It is important to keep the circulating water system clean, through blowdown and chemical treatment of the circulating cooling water, to prevent corrosion and fouling of the heat transfer surfaces both in the condenser and the cooling tower.

Although proper maintenance is a key to good cooling tower performance as it is in main steam condensers, there are opportunities for improving cooling tower performance by upgrading the fill. For example, reducing cooling tower approach (difference between circulating temperature leaving the cooling tower and inlet air wet bulb temperature) from 10 to 5°F on a warm summer day will improve turbine cycle heat rate by 20-40 Btu/kWh. Newer fill materials and designs have improved configurations with better heat transfer characteristics. Also, VFD applications for circulating water pumps and mechanical draft fans will reduce auxiliary power use and increase net unit power output.
Condenser pressure is also affected by the condenser thermal duty. Thermal duty of a condenser can be reduced through recovery and use of low-temperature heat from the condenser or a circulating water system. Possibilities include: preheating of combustion air (for power plants located in northern climates), building heat, and other low-temperature heat uses. Another possibility involves application of the Rankine-Kalina cycle, which can improve cycle efficiency by up to 23% (Korobitsyn, M.A., 1998). However, retrofit to an existing older power station might be difficult, but should be considered as part of a repowering project.

Improved Performance of Boiler Auxiliaries
Boiler auxiliaries are absolutely essential to boiler operation, and have significant effect on boiler and unit performance. Boiler auxiliaries, analyzed in this project include regenerative APHs and forced draft (FD) and induced draft (ID) main fans. Details are provided in Appendix IV.

Air Preheaters and Factors Affecting their Performance
The APH transfers sensible heat in the flue gas leaving the boiler to the combustion air, through regenerative heat transfer surfaces in a rotating (Ljungstrom) or stationary (Rothemuhle) heat transfer matrix, thereby increasing boiler efficiency and reducing heat rate. A 25°F change in flue gas temperature leaving the APH results in approximately 1% change in net unit heat rate, with corresponding change in CO₂ emissions.

Due to differences in static pressure between flue gas and combustion air streams, combustion air leaks into the flue gas stream. For Ljungstrom APHs air leakage typically varies from 8 to 12% (by weight) for secondary air (SA) APHs, and 12 to 25% (or higher) for the primary air (PA) APHs. For Rothemuhle APHs, air leakages in the 25 to 30% range are not uncommon (Howden Power Ltd., 1996). Air leakage not only affects APH performance, but has an adverse effect on unit performance. Air leaking from the combustion air to flue gas stream is not participating in the combustion process, and represents additional burden on the FD and ID fans. As the air leakage increases, the FD and ID fan power increases, increasing the station service power and net unit heat rate. For example, a 10%-point increase in APH leakage (e.g., increase from 6 to 16%) increases station service power by 11%, and net unit heat rate by 0.25% (relative). For a tri-sector APH the heat rate penalty is higher because the high-pressure PA from the PA sector leaks into the SA and flue gas sectors, resulting in higher PA fan power, in addition to higher FD and ID fan powers. Eliminating APH leakage by using leakless gas-to-gas heat exchangers, or heat pipe heat exchangers will improve net unit heat rate by approximately 0.15%.

Besides affecting station service power and net unit heat rate, APH air leakage has a negative effect on performance of air pollution equipment by reducing treatment (residence) time due to higher flow rate of the flue gas. Also, air leakage will have a negative effect on the post-combustion CO₂ capture system and its efficiency. The size and cost of the post-combustion CO₂ capture system is proportional to flow rate of the flue gas that needs to be treated. Therefore, efficiency is affected by the concentration of CO₂ in the flue gas, which is lowered by the air in-leakage. In the oxy-fuel retrofit case,
any air leakage will have a severe negative effect on plant efficiency, retrofit cost, and CO₂ purity, and must be eliminated. This will require zero-leakage heat exchangers when operating in the oxy-fuel mode.

The transfer of heat from the hotter flue gas stream to the colder air stream creates temperature gradients which cause thermal distortions of the APH components. The relative distortion of the APH components affects clearances between seals and sealing surfaces. Therefore, control of APH leakage is not an easy task, especially in the case of a Rothemuhle APH. Application of advanced seal designs and doubling the number of radial seals can reduce air leakage in a Ljungstrom APH by a factor of two. Unfortunately, there are no good seal designs for Rothemuhle APHs. Even with advanced seal designs, APH leakage has to be checked on annual basis, and seals need to be adjusted or replaced to maintain reduced levels of APH air leakage and bypass.

APH performance is affected by the plant and APH operating parameters. The most important factor is the ratio of air and flue gas flow rates through the APH heat transfer matrix, which is proportional to the capacity rate ratio Cₓ (also known in the industry as the X ratio). An increase in boiler air in-leakage results in higher excess O₂ levels measured at the economizer outlet, and in order to maintain the excess O₂ set-point, the combustion control system reduces flow rate of the combustion air. This reduces Cₓ and results in higher temperature flue gas leaving the APH and higher net unit heat rate. For example, an increase in the boiler air in-leakage from 5 to 10% results in an increase in net unit heat rate by 0.4%. For best unit performance it is important to keep boiler air in-leakage at a minimum practically achievable level.

Operation of a regenerative APH represents a compromise between performance and maintenance. As temperature of the flue gas leaving the APH decreases, unit performance improves. Lower flue gas temperature, however, results in lower temperature of the heat transfer matrix and increases size of the acid deposition zone in the cold end (CE) layer of the APH. As discussed in Appendix I, flue gas is typically cooled to approximately 300°F to maintain an “acceptable” level of sulfuric acid condensation on the APH heat transfer surfaces and downstream ductwork. Deposition of sulfuric acid causes corrosion of APH heat transfer surfaces and fouling and plugging of APH heat transfer passages. Reduced cross-sectional areas result in increased air- and gas-side pressure drops across the APH, which increases fan power requirements.

Sulfuric acid (H₂SO₄) is formed as a vapor in the boiler by the association of sulfur trioxide (SO₃) with water vapor. In the 660 to 600°F temperature range, both SO₃ and H₂SO₄ are present in the flue gas, but H₂SO₄ is dominant. Below 600°F, SO₃ is almost completely converted to H₂SO₄. The SO₃ is initially formed by the reaction of sulfur dioxide (SO₂) with atomic oxygen in the post-flame region of the furnace and by the catalytic (heterogeneous) oxidation of SO₂ with molecular oxygen in the convective pass of the boiler. Typically 0.7 to 1% of SO₂ is converted to SO₃ through homogenous reactions. Heterogeneous reactions are responsible for approximately 1% conversion of SO₂ to SO₃, but the actual conversion ratio depends on many factors. Some of the SO₂ (0.3 to 2%) is oxidized to SO₃ within passages of the selective catalytic reduction (SCR)
reactor. Application of advanced catalysts reduces the \( \text{SO}_2 \) to \( \text{SO}_3 \) conversion in the SCR to 0.1%.

The acid dewpoint temperature is a function of \( \text{SO}_3 \) and \( \text{H}_2\text{O} \) concentrations in the flue gas, and increases with an increase in concentration. For \( \text{SO}_3 \) concentration of 5 ppmv and \( \text{H}_2\text{O} \) concentration of 7% by volume, the acid dewpoint temperature is 260°F. As temperature decreases below the acid dewpoint, sulfuric acid condenses in the flue gas stream forming mist, or on metal surfaces forming hygroscopic and sticky layer. Water vapor from the flue gas is attracted to this initial layer forming a layer of dilute and very corrosive sulfuric acid. Fly ash sticks to this layer forming deposits.

The ease of removing these deposits depends on the mineral content of coal. For most bituminous coals, they can be removed easily (as is the case for Illinois coals). For the case of high-alkali coals (western coals and lignites) calcium and magnesium oxides from fly ash are sulfated on the APH furnace forming hard-to-remove deposits. If severe plugging occurs, the unit might become fan-limited, and load derate may be needed until the APH is washed and the APH pressure drop (\( \Delta P_{\text{APH}} \)) is restored. In the case of high-alkali coals, the \( \Delta P_{\text{APH}} \) might not be fully restored by water-wash only and, after a few years of operation, APH baskets need to be replaced. Corrosion of APH heat transfer surfaces results in loss of heat transfer surface, reduced heat transfer, reduced basket life, higher temperature of flue gas leaving the APH, and higher net unit heat rate. A 50% loss of heat transfer surface in the CE layer of a medium-size APH results in a heat rate penalty of approximately 20 Btu/kWh.

Operating experience shows that regenerative APHs are vulnerable to fouling with ammonium bisulfate (ABS) deposits, resulting from the operation of the ammine-based \( \text{NO}_x \) removal equipment, such as SCR and SNCR reactors. Ammonia (\( \text{NH}_3 \)) slip is practically an unavoidable consequence of injecting ammonia or urea in the flue gas for \( \text{NO}_x \) reduction. When ammonia slip occurs, ammonium sulfates form in the presence of \( \text{SO}_3 \) in the flue gas. The APH fouling prevention criteria specify that \( \text{SO}_3 \) levels lower than 2-3 ppmv and \( \text{NH}_3 \) levels lower than 1-2 ppmv are required to avoid APH fouling by ammonium salts.

The reaction of \( \text{NH}_3 \) and \( \text{SO}_3 \) in the presence of water vapor begins at elevated temperatures (550-650°F) forming ABS and ammonium sulfate (AS). ABS is hygroscopic, corrosive, sticky and difficult to remove in its solid state, while AS is formed as a dry non-sticky powder. AS particles are small (less than 10\( \mu \text{m} \)), difficult to remove in the ESP, and can contribute to PM\( _{10} \) emissions and opacity. ABS formation temperature depends on \( \text{SO}_3 \) and \( \text{NH}_3 \) concentrations. The Hitachi-Zosen and Radian-EPA correlations are available for prediction of the ABS formation temperature. There is a significant discrepancy between predicted ABS formation temperatures, with Hitachi-Zosen predictions being substantially higher. One of the reasons for this discrepancy is due to a difference in assumed reaction paths. From an equilibrium point of view Radian-EPA correlation should provide better predictions of ABS formation temperature compared to Hitachi-Zosen (Tavoulareas, 2006). The Radian-EPA correlation was used in this study because its predictions seem to be in a better agreement with field
observations compared to Hitachi-Zosen. For SO$_3$ and NH$_3$ concentrations of 5 ppmv, ABS formation temperature predicted by Hitachi-Zosen correlation is approximately 322°F.

Once formed in the flue gas, ammonium compounds deposit on the APH heat transfer surfaces and increase flow resistance. This results in increased $\Delta P_{APH}$ and fan power requirements, and reduction in net unit power output. Excessive increase in $\Delta P_{APH}$ can result in unit derates due to fan power limitations and cause unscheduled unit outages for APH cleaning. Precipitation of ABS from the gas state will continue until its freezing point is reached (approximately 300°F), establishing a narrow formation temperature (and deposition) window typical of the hot-intermediate (HI) layer baskets. The size and location of ABS deposition zones determined using the Radian-EPA correlation and the Siemens design guideline to predict ABS formation temperature are presented in Figure 8. Temperatures of the heat transfer matrix were calculated by the RPHMT code. The predicted ABS deposition zone is very narrow when Radian-EPA correlation is used and its size and location is in agreement with field observations. The APH fouling problem is further aggravated by the fly ash adhering to the sticky ABS layer, breaks between the APH layers, and deposition of sulfuric acid in the CE layer.

![Secondary APH Model](image)

**Figure 8:** Acid and ABS Deposition Zones in a Typical APH

APH fouling and corrosion can have a significant impact on unit performance and availability. The net unit heat rate is affected by higher temperature flue gas leaving the APH, which is caused by reduced heat transfer or loss of the heat transfer surface due to corrosion, and by higher FD and ID fan power requirements due to increased $\Delta P_{APH}$. The unit availability can be compromised by scheduled and unscheduled APH water-washes which are needed to remove fouling deposits and restore, if possible, $\Delta P_{APH}$. The options, available for controlling fouling and corrosion of the heat transfer surfaces in the CE and
HI layers include: sootblowing, water-washing, increased cold end temperature, reduction of SO$_3$ concentration in the flue gas, APH modifications, and complete APH replacement.

If it can be performed during a scheduled unit outage, water-washing does not affect unit availability. Unscheduled water-washing reduces unit availability, and there is a great incentive to reduce the number of required water-washes. This could be accomplished by better cleaning of the APH with sootblowing equipment (regular or high-energy sootblowers). The smaller the deposition zone, and the closer it is to the CE of the APH, the more effective are APH sootblowers in controlling acid and ABS deposition.

One of the most commonly used options for mitigating deposition, corrosion, and pluggage involves increasing the temperature of air into the APH by preheating in a steam air heater (SAH). Steam for the SAH is extracted from the steam turbine. Higher temperature inlet air to the APH results in higher temperature of the heat transfer matrix. The effect of air preheating on temperature of the APH heat transfer matrix, and location and size of the acid and ABS deposition zones, is presented in Figure 9. Higher cold end temperature reduces size of the acid and ABS deposition zones by moving the onset of deposition closer to the APH cold end. For example, increasing the inlet air temperature from 80 to 160°F shifts the onset of acid deposition from the HI layer to the CE layer, shrinking the size of the acid deposition zone by a factor of four. The ABS deposition zone is moved 6” closer to the cold end and is shrunk in size by 35%. However, an increase in the APH inlet air temperature in the SAH, increases temperature of the flue gas leaving the APH, and results in higher net unit heat rate due to higher flue gas loss and higher extraction from the steam turbine.

Figure 9: Effect of Inlet Air Temperature on Acid and ABS Deposition Zones
The advanced air preheat, described in a section “Recovery and Utilization of Heat from Flue Gas” and in Appendix I, represents an option for increasing the APH air inlet temperature to mitigate deposition of sulfuric acid and ABS, without negatively affecting unit performance. A schematic representation of this option is presented in Figure 5. The effects of the advanced air preheat and SAH preheat on net unit heat rate are compared in Figure 10 where corresponding heat rate changes are presented as functions of the APH air inlet temperature. The heat rate penalty due to SAH air preheating is the total penalty due to higher temperature flue gas leaving the APH and higher steam extraction. This penalty increases as the inlet air temperature is increased. In the case of advanced air preheating, the net unit heat rate improves as the APH inlet air temperature is increased because the heat from the flue gas is recovered and used for air preheating. As the amount of heat recovered from the flue gas increases, the flue gas temperature decreases, reducing the stack loss and improving unit performance.

![Figure 10: Comparison of the SAH and Advanced Air Preheating](image)

In the absence of any real-time indication of the matrix temperature, plant engineers rely on the flue gas temperature, measured at the APH outlet, and CEAT guidelines provided by the APH manufacturer to maintain “acceptable” levels of acid condensation in the APH. However, as shown in Figure 4-64 in Appendix IV, the difference between flue gas temperature at the APH outlet and metal matrix temperature is large, in excess of 100°F, with metal temperatures being lower. Therefore, APH modeling is needed to determine the temperature of the metal matrix, the onset of acid and ABS deposition, and the size of the acid and ABS deposition zones, and to analyze effects of the plant and APH operating conditions on acid and ABS deposition, and to determine the proper temperature of inlet air.
The lower the SO$_3$ concentration at the APH inlet, the lower the sulfuric acid dew point and the lower the potential for corrosion. Therefore, if the SO$_3$ level at the APH inlet is reduced, the APH can be operated with a lower outlet gas temperature, allowing the APH to recover additional heat. Also, the potential for ABS formation and fouling is greatly reduced. The most popular procedures for reducing SO$_3$ concentration in the flue gas stream involve injection of a sorbent into the fuel stream, into the furnace, or into the flue gas stream. The sorbent reacts with SO$_3$ in the flue gas to form a solid compound that is collected in the ESP or baghouse. Typically used sorbents include limestone (added to the coal feed), sodium bisulfite solution (injected into the flue gas stream upstream of the APH), trona (sodium carbonate) or hydrated lime (injected upstream of the APH), and ultrafine limestone (injected upstream of the APH). Alkali (limestone) injection also helps mitigate SCR catalyst poisoning by arsenic.

APH design modifications to improve cleanliness of heat transfer surfaces include deep CE layer, use of better materials, and heat transfer elements with closed flow channels. A complete replacement of the APH is the most expensive option, and is warranted in situations where structural integrity of the old APH is compromised, baskets in all layers need to be replaced, and air leakage is very high. For example, this would be the case where an old Rothemuhle APH with air leakage exceeding 30% and corroded and damaged baskets is replaced by a modern Ljungstrom APH employing modern seals and high-efficiency heating elements.

**Auxiliary Power Use**

A reduction in auxiliary power use represents an important option for improving net unit heat rate; a 10% reduction in auxiliary power use will improve net unit heat rate by approximately 1.1% (relative). Opportunities for reducing auxiliary power loads include streamlining of the power plant ductwork, replacing mechanical draft towers with natural draft towers, and reducing electric drive power requirements. Use of variable speed frequency drives (VFDs) to reduce power consumption of main fans (PA, FD, and ID) was analyzed in this project. VFD drives allow fan pressure rise to be matched exactly to the system resistance without throttling of the fan discharge pressure and associated power losses. VFDs can also be used to reduce power requirements of the circulating water pump drives and fan drives on mechanical draft towers.

For a subcritical unit, main fans (PA, FD, and ID) contribute to 18.8% of the auxiliary power use. Savings achieved by application of VFDs depend on the plant load profile. For a near base-loaded plant operating at 100% MCR 74% of the time (load profile 1), the ID fan power savings due to VFDs are approximately 18%. For the same unit, operating at 100% MCR 30% of the time, and at 70% maximum continuous rating (MCR) 40% of the time (load profile 2), the ID fan power savings are considerably larger, approximately 44%. Assuming VFDs are installed on all main fans, the auxiliary power savings for load profile 1 will be approximately 3.4%, resulting in a 0.34% relative improvement in net unit heat rate. For load profile 2, the auxiliary power savings will be 8.3%, corresponding to a 0.93% relative improvement in net unit heat rate.
Improvements to Combustion Sensors and Control

Combustion control is achieved by adjustments to coal and air flows to maintain an adequate firing rate, and steam flow to the steam turbine needed to generate electric power output requested by the power dispatcher. Accurate measurement of fuel and combustion air is important to obtain best achievable net unit heat rate and lowest CO₂ emissions. Additionally, other process parameters such as excess O₂ and unburned fuel (expressed as LOI) are important for combustion monitoring, boiler safety, performance improvement and reduction of CO₂ emissions.

In addition to combustion monitoring, the control of combustion affects a number of important performance, operational, and environmental parameters, and can contribute to achieving CO₂ emissions reductions through efficient combustion. Combustion monitoring and control depends on the accurate measurement of combustion air flow rate, excess O₂ level, CO emissions, LOI, steam (or feedwater), and coal flow rate. Improved combustion control has a positive effect on unit performance and emissions.

Technology review was performed to identify improvements in sensors for measurement and monitoring of the following combustion parameters: combustion air, excess O₂, CO, fly ash sampling, and on-line LOI analysis. The performance characteristics of combustion sensors for measurement and monitoring of aforementioned combustion parameters are presented in Appendix V. Additionally, deficiencies of current combustion measurements and combustion control strategy are discussed and suggestions for improvement are presented.

The measurement and control of combustion air flow is a key to the proper functioning of the boiler control system. Accurate measurement of the combustion air flow is difficult. In a coal-fired power plant, the air flow measurement is typically based on a differential pressure Venturi or flow nozzles, and air foil devices. This technology is marked by low accuracy (15 to 30%), low turn-down ratios, and is characterized by significant pressure drop, undependable repeatability and reliability, and unsettled maintenance practices.

The conventional combustion control system for coal-fired boilers includes analysis of the flue gas. This measurement is based on an old technology that samples excess O₂ at the economizer outlet plane by a small number of probes, assuming even distribution of fuel and combustion air between the burners. Such combustion control is sensitive to stratifications in excess O₂ level resulting from changes in boiler operating parameters that are unrelated to changes in combustion air flow.

Also, the conventional combustion control cannot account for changes in air in-leakage into the boiler and it controls the excess O₂ level at the boiler exit, instead of at the furnace exit. Because combustion process is governed by the excess O₂ level at the furnace exit, this combustion monitoring scheme does not provide adequate control of the combustion process. As the air in-leakage increases, the measured value of excess O₂ at the boiler exit increases and the combustion control system reduces the flow rate of combustion air to maintain the excess O₂ set-point. This results in lower furnace excess O₂ level, increased LOI levels and CO emissions, higher furnace exit gas temperature.
(FEGT), increased furnace and pendant slagging, higher net unit heat rate, and increased CO₂ emissions. For a power plant firing bituminous coals, an increase in boiler air in-leakage from 5 to 10% will result in net unit heat rate penalty of approximately 0.9%. Because the boiler air in-leakage cannot be measured on-line, an increase in boiler leakage will typically remain unnoticed over a significant period of time.

Advances in tunable diode laser spectroscopy (TDLS) technology allow non-intrusive measurements of excess O₂ level, temperature, and other parameters to be performed in the furnace. This technology also allows mapping of spatial stratification by using multiple sensor pairs. A conventional combustion control system can be greatly improved by applying TDLS and other technologies for air and coal flow control to individual burners. The coal flow control technology is described in Appendix VI.

An improved combustion control system, presented in Figure 11, where spatial distribution of excess O₂, CO and temperature is measured at the furnace exit plane by an array of non-intrusive sensors, would have many advantages compared to a conventional combustion control system (Sarunac, 2003). First, the effect of changes in boiler air in-leakage on control of combustion air is eliminated allowing continuous operation with the lowest possible excess O₂ level, and resulting in improvement in net unit heat rate by up to 100 Btu/kWh (1%). Second, the effects of shifts in spatial stratification of excess O₂ are eliminated, resulting in a more stable operation and better combustion efficiency. Third, the O₂ probe drift, caused by plugging or leakage, is eliminated, allowing operation with lower excess O₂ level. Fourth, on-line information on O₂, CO and temperature stratification patterns, measured at the furnace exit, can be used to diagnose and correct fuel and combustion air maldistribution problems, allowing continuous operation with the lowest possible excess O₂ level, fly ash LOI, and CO emissions. The advantage of this approach is that all required components are commercially available, and could be retrofitted in stages.

![Figure 11: Improved Combustion Control Scheme](image-url)
The most common approach to coal-fired boiler control is an uncoordinated arrangement of single-input-single-output (SISO) feedback loops based on proportional-integral-derivative (PID) controllers. A PID controller owes its popularity to the fact that it does not require a dynamic model of the plant since the structure of the controller is fixed. The PID-based control system is tuned by adjusting controller gains. Tuning is done on an empirical basis, sometimes by personnel lacking sufficient control background, which can result in a poorly-tuned control system. Another limitation of this control system architecture resides on the selection of control set-points, which are ultimately left to plant operators and often result in sub-optimal values in terms of plant performance.

The increasing demand for highly-efficient boiler operation and reduction of CO₂ emissions requires implementation of novel control system architectures that exploit high-performance process models for control and real-time optimization of the objective function, while satisfying operating and environmental constraints. The objective function may include overall system efficiency, cost, or a combination of both. To achieve overall system optimization, the control system architecture must follow an integrative approach by taking into account interdependencies of different subsystems, which is neglected by control architectures based on SISO control loops.

As discussed in Appendix V, control system retrofits can result in heat rate improvements in 1 to 2% range, with higher values corresponding to cycling units and units with old pneumatic control systems. For a base-loaded 600 MW unit firing bituminous coal, 1% improvement in net unit heat rate represents total annual savings of $1.4 million. Accounting for CO₂ emissions (at $40/ton CO₂) more than doubles annual savings.

For every boiler there is an optimal value of excess O₂ level at which net unit heat rate is at its minimum value, given operating and environmental constraints. The optimal O₂ value depends on many operating and maintenance factors. As maintenance condition changes, the optimal value of excess O₂ changes, and typically increases with deterioration of combustion hardware. Any deviation in the actual excess O₂ level from its optimal value will result in a heat rate penalty.

Except in the case where an increase in boiler air in-leakage is not detected and furnace excess O₂ is lower than required for good combustion, boilers are typically operated with excess O₂ levels higher than the optimal value. For the medium LOI level, 1%-point increase in excess O₂ (e.g. increase from 2.8 to 3.8%) results in approximately 20 Btu/kWh increase in net unit heat rate. Each additional 0.5%-point increase in O₂ adds a 20 Btu/kWh penalty.

**Coal Flow Balancing in PC-Fired Boilers**

Poor coal flow distribution to burners is a common problem in pulverized coal (PC) fired boilers and has been considered to be an area that needs to be addressed for improving unit performance, emissions, operations, and maintenance. There are numerous studies showing the benefits of coal balancing between the burners on unit emissions, efficiency, and operating conditions. An overview of the available coal flow control technologies
and their capabilities is presented in Appendix VI, along with description of the coal flow controller device developed by the ERC and three case studies.

In a PC-fired boiler, coal particles, after being ground in mills, are carried to burners via primary air (PA) flow through a complex network of coal pipes. A mixture of coal and PA flow leaving the mill through a main distributor pipe is distributed into a number of burner lines using mechanical flow-splitting devices. A riffler is the most commonly used flow splitter configuration in U.S. power plants. It consists of a number of alternating flow passages, directing the mixture of coal and air to a designated burner line. Although rifflers help improve coal flow distribution between burners, relatively large imbalances in coal flow can exist at the riffler outlet due to the presence of strong stratification in coal flow (referred to as a coal rope) at the inlet to the riffler.

Another common coal flow splitting mechanism is the multiple outlet discharge turret in pressurized mills. The flow distribution between coal pipes is achieved as the coal and PA mixture leaves the pulverizer through a number of outlet coal pipes, each of which is carrying flow to an individual burner. Similar to the riffler type flow splitters, the multiple-outlet discharge turret splitting mechanism also suffers from severe stratification in coal flow as a result of strong flow rotation in the discharge turret.

With the introduction of low-NOₓ burners, coal distribution between burners has become even more important, as they have reduced tolerance to poor coal distribution. Initially, boiler manufacturers offered riffler devices for even coal distributions between burners. Later on, modified riffler designs were offered for breaking up particle ropes prior to entry into the riffler device. Neither was very successful.

There is significant development effort among boiler manufacturers and equipment companies for developing technologies that can be used to uniformly distribute coal and primary air flow among burner pipes. These efforts can be categorized into four groups: (1) Static/dynamic flow mixers (diffusers) upstream of the splitter, (2) Flow restricting devices (fixed or variable area orifices), (3) Dampers for directing flow into designated pipes, and (4) Coal flow control via streamlined objects.

Laboratory experiments and numerical analysis were conducted at the ERC to develop and evaluate static mixers, flow restricting devices, and other two-phase mixing concepts (Bilirgen, 2000). The study showed that with static mixers, a relatively uniform particle concentration distribution could be achieved after approximately six pipe diameters downstream of an elbow at the expense of high pressure drop. Space constraints and PA fan discharge pressure are, however, limiting factors for installing static flow mixers in coal pipe networks. There are a number of field installations of static flow mixers, however, utility experience and published results on the success of the flow mixer concept are inconsistent. Experiments conducted with fixed and variable area orifice plates confirmed that these devices, although very effective for balancing air flow rate in coal pipe networks, have little effect on distribution of coal flow between coal pipes.
Some boiler manufacturers offer flow splitter devices featuring dampers installed upstream of the flow splitting point to provide on-line adjustments to the coal and PA flows into outlet pipes. Although, these dampers are more effective than orifice plates in controlling coal flows they have a large effect on the PA flow distribution between outlet pipes. Low PA flow can result in saltation and coal pipe pluggage. In addition, large variations in PA flow among coal pipes can result in decreased combustion efficiency, higher net unit heat rate, and higher NOx emissions. Therefore, these dampers are not recommended for balancing of coal flow in coal-fired power plants.

The coal flow controller based on streamlined objects was developed by the ERC. The flow controller employs specially designed adjustable flow control elements positioned upstream of the riffler. Control of the coal flow distribution is achieved by using a series of flow control elements connected to adjustment rods, which can be traversed back and forth changing the coal particle concentration pattern at the riffler inlet. Flow control elements are designed to allow balancing of coal flows without affecting the PA flow distribution between coal pipes.

This coal flow control technology makes it possible to balance coal flows to burners in piping systems where a single coal pipe is divided into two, three or four outlet pipes at a splitter junction. It was successfully applied to ten PC-fired power plants not only for balancing coal distribution between burners, but also for proving that balanced coal distribution results in improvements in unit emissions, performance, and operation. Typical benefits of coal flow balancing, determined in field studies, include: reduction in fly ash LOI by more than 25%, heat rate improvement by almost 1%, reduction in CO emissions by 15%, and reduction in NOx emissions (due to lower excess air operation).

Besides the coal flow balancing capability, the ERC coal flow control technology can be used to achieve a desired coal flow distribution between coal pipes, which is sometimes necessary to maintain constant combustion stoichiometry for individual burners in cases where there is stratification in the secondary air flow between burners due to the windbox design or maintenance problems. Results of three case studies where the flow controller was used for balancing of coal flow between coal pipes, and for achieving desired distribution of coal flow between the burners, are described in Appendix VI.

Despite the importance of proper coal flow balancing, there are few options for utility engineers to improve coal flow distribution among burners. The first challenging issue is repeatable measurement of coal flow distribution in coal pipes. There are mechanical, ultrasonic, and electrostatic charge-based off- and on-line devices for measuring flow rate of coal in coal pipes. Depending on the application, these devices may have poor coal measurement accuracy. The second challenging task is the choice of a mechanism/device for controlling coal flow distribution among burners. There are a number of designs proposed by equipment manufacturers for controlling and balancing coal flows between burners. However, their performance is questionable as shown by mixed results published in the literature. The coal flow controller, developed by the ERC, has recently been evaluated by EPRI with excellent results in controlling coal distribution among outlet coal pipes.
Combustion Optimization

As the environmental pressure on coal-fired power plants increases, plant owners are looking for cost-effective solutions to reduce emissions (SO\textsubscript{x}, NO\textsubscript{x}, and more recently mercury) from coal-fired power plants and improve their performance and economics. Combustion optimization is a cost-effective approach for reducing emissions and optimizing performance of existing combustion and pollution control equipment. It requires minimal capital investment and in addition to optimized operation, it also results in improved understanding of the effects and importance of key operating parameters on unit performance and emissions.

Combustion optimization is a process where plant operating parameters are manipulated to achieve an optimization goal, such as maximum emission reduction with minimum impact on plant performance. Plant-specific operating and environmental conditions, such as CO emissions, opacity, steam temperatures, and slagging, impose constraints. Therefore, combustion optimization is typically a constrained optimization problem. Combustion optimization can be used as an alternative to modifications to the firing system for emissions reduction, or in conjunction with these to maximize performance of firing and post-combustion emission control systems. It should be noted that boiler and SCR or SNCR optimizations are inter-dependent, since the post-combustion system is very much affected by combustion. Therefore, combustion optimization should consider the integrated systems.

Based on long experience with performance and combustion optimization of utility boilers, the ERC has developed a practical and cost-effective procedure for combustion optimization, based on understanding of the underlying physics and boiler operations. It has been used to optimize more than 30 utility boilers of different size and design burning a wide range of fuels. The combustion optimization approach and results of four case studies are presented in detail in Appendix VII.

Field experience shows that the ERC combustion approach can reduce NO\textsubscript{x} emissions by 25 to 30% regardless of boiler size, firing system design, fuel fired, and baseline NO\textsubscript{x} level. Heat rate can be improved by up to 1%, depending on operating constrains and coal characteristics (reactivity, LOI, and slagging propensity). A summary of heat rate improvements achieved in PC-fired boilers is presented in Table 1. Mercury emissions, when used as the optimization objective, can be reduced by as much as two-thirds for power plants firing bituminous coals. For power plants firing Western sub-bituminous coals, mercury emissions can be reduced by one-third. Results show that heat rate improvements are larger for tangentially-fired boilers, compared to wall-fired. This is because maldistribution of air and fuel among burners in wall-fired boilers imposes operating (high LOI) or emissions/safety (high CO) constraints. Since combustion optimization involves minimal capital investment by optimizing existing hardware, it represents an attractive and cost-effective method for reducing emissions from coal-fired power-plants and improving their performance and profitability.

Given that the ERC and most other combustion optimization approaches depend on a data-based model describing the effect of boiler control settings on emissions and
performance, creating a good database through a series of field tests is of utmost importance. Selection of key operating parameters and development of a test protocol are also critical. The database is used to correlate test data by artificial neural networks (ANNs). ANNs are then used to determine optimal operating settings by employing a mathematical or genetic optimization algorithm. Achieved results are greatly dependent on test preparations, including instrument calibration, proper operation and tuning of the control system and actuators, mill adjustments, and proper operation of the combustion hardware.

Table 1: Summary of Heat Rate Potential Improvements in Coal-Fired Boilers

<table>
<thead>
<tr>
<th>Unit No.</th>
<th>Boiler Characteristics</th>
<th>Fuel Type</th>
<th>Unit Size [MW]</th>
<th>Heat Rate Improvement: $HR_{avg. BL} - HR_{min.}$ [Btu/kWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4-Corner, LNCFS Level III LNB</td>
<td>BIT</td>
<td>90</td>
<td>23</td>
</tr>
<tr>
<td>2</td>
<td>8-Corner, LNB, OFA</td>
<td>BIT, SUB</td>
<td>245</td>
<td>39</td>
</tr>
<tr>
<td>3</td>
<td>Separate Furnaces, TFS2000 LNB</td>
<td>BIT, SUB</td>
<td>285</td>
<td>48</td>
</tr>
<tr>
<td>4</td>
<td>4-Corner, TFS2000 LNB</td>
<td>SUB</td>
<td>400</td>
<td>84</td>
</tr>
<tr>
<td>5</td>
<td>8-Corner, LNB, OFA</td>
<td>BIT, SUB</td>
<td>535</td>
<td>105</td>
</tr>
<tr>
<td>6</td>
<td>Front Wall-Fired, CB, FGR</td>
<td>BIT</td>
<td>300</td>
<td>5 (61@ Part Load)</td>
</tr>
<tr>
<td>7</td>
<td>Opposed Wall-Fired, LN Cell Burners</td>
<td>BIT, SUB</td>
<td>750</td>
<td>16</td>
</tr>
<tr>
<td>8</td>
<td>Front Wall-Fired, Twin Furnace, CB</td>
<td>BIT, SUB</td>
<td>280</td>
<td>21</td>
</tr>
<tr>
<td>9</td>
<td>Opposed Wall-Fired, CB, DRB</td>
<td>SUB</td>
<td>600</td>
<td>25</td>
</tr>
<tr>
<td>10</td>
<td>Front Wall-Fired, LNB, OFA</td>
<td>BIT, SUB</td>
<td>135</td>
<td>32</td>
</tr>
<tr>
<td>11</td>
<td>Opposed Wall-Fired, DRB-LNB, OFA</td>
<td>BIT, SUB</td>
<td>650</td>
<td>55</td>
</tr>
<tr>
<td>12</td>
<td>4-Corner, LNCFS Level III LNB, SCR</td>
<td>BIT</td>
<td>150</td>
<td>54</td>
</tr>
</tbody>
</table>

Abbreviations: BIT=Bituminous Coal, SUB=Sub-bituminous Coal (PRB or imported), CB=Conventional Burners, LNB=Low-NOx Burners, LNCFS=Low-NOx Concentric Firing System, TFS=Tangentially-Fired System, DRB=Dual Register Burners, OFA=Overfire Air, FGR=Flue Gas Recirculation, SCR=Selective Catalytic Reduction

As stated earlier, combustion optimization is a constrained optimization problem. Therefore, for best results it is important to remove or relax operating constraints. Combustion tuning is a process of eliminating or mitigating operating constraints through adjustment of the combustion system, coal mills and, if necessary, balancing of coal flows in coal pipes. It is, therefore, a necessary step in the combustion optimization process.

Several options are available for implementation of optimal boiler control settings, including real-time open-loop advisory, programming optimal settings into the plant DCS, closed-loop control for key operating parameters, and full closed-loop control. The choice depends on the size of the unit, capabilities of the plant control system, degree of automation, availability of the actuators, coal quality variation, and plant load profile.

Approximately 280-300 coal-fired boilers have used optimization software provided by several vendors. Presently, there are 100 to 130 coal-fired units in the United States that are using optimization software in a closed-loop mode. Field experience has shown that
closed-loop systems are not good options for older power plants and for power plants without digital control systems, adequate instrumentation, and some degree of automation. Real-time on-line advisory is a cost-effective solution for such units. Industry experience confirms earlier estimates about performance improvements that can be achieved by optimization. NO\textsubscript{x} emissions can be reduced by 5-35\% depending on the number of control variables available, the operating range of each variable, and whether the boiler was tuned prior to the optimization. Heat rate in base-loaded units can be improved by up to 1\% and in load-following and cycling units up to 2\%. Units that have not been recently tuned, and units with many control variables and a wide operating range for each variable, should achieve performance improvements at the high end of the heat rate improvement range.

Maintaining optimal settings on a long-term basis can be challenging. For example, as the maintenance condition of the firing system degrades over time, operating constrains change, typically reducing the benefits. Although, adaptive closed-loop neural network controllers can deal with these changes, the result of such passive control strategy is an undesirable deterioration in performance and an increase in emissions. A proactive, back-to-the basics approach, focusing on maintaining top performance of the boiler firing, milling and control systems is recommended by the ERC. The following periodic activities are recommended: bi-annual combustion tuning to maintain best performance of the firing system, monthly coal fineness tests to track mill performance, and quarterly fine-tuning of the combustion control system. In addition, inspection of the combustion hardware should be performed at every opportunity to identify and correct any damage.

Four case studies, described in Appendix VII, report combustion optimization of a tangentially-fired boiler firing Eastern bituminous coal, a tangentially-fired boiler firing blends of Western and Eastern coals, a wall-fired boiler firing blends of Western and Eastern coals, and combined optimization of a tangentially-fired boiler and SCR, where the boiler is firing Northern Appalachian coal. The objective of the first case study was to achieve target NO\textsubscript{x} emission levels and minimize performance penalty due to low NO\textsubscript{x} operation. The objective of the second case study was determination of boiler control settings resulting in low NO\textsubscript{x} operation, best net unit heat rate, and FEGT values below an empirically-determined slagging limit. The third case study involved improvement of unit performance, determination of optimal boiler control settings over a range of target NO\textsubscript{x} levels, and reduction of mercury emissions. The objective of the fourth case study was minimization of the overall cost of NO\textsubscript{x} emissions compliance, constrained by ABS fouling of the APH.

**Sootblowing Optimization**

Furnace and convection pass slagging and fouling have a detrimental effect on boiler performance and emissions and represent the primary cause of reduced operating efficiency and availability in fossil-fired boilers. Furnace slagging reduces heat transfer to the waterwalls, and increases the amount of heat available to the convection pass. This results in higher furnace exit gas temperature (FEGT), higher steam temperature and desuperheating spray flows, and higher NO\textsubscript{x} emissions. As the convection pass of a boiler slags and fouls, heat transfer decreases, resulting in a decrease in steam
temperature and desuperheating spray flows, and in an increase in flue gas temperature at the boiler exit.

Sootblowing is used to control the level of ash and slag deposits on the boiler heat transfer sections. On-line cleaning of localized areas is done by sootblowers using high-pressure steam or air. Wallblowers are used to remove slag from furnace waterwalls, while retractable blowers are used to clean the convection pass of the boiler. Furnace cleaning increases radiation heat transfer to waterwalls and reduces FEGT. This decreases the amount of heat available to the convection pass. Over-cleaning of furnace walls can result in low steam temperatures with resulting heat rate penalties and increased moisture levels and erosion damage in the last stages of the LP turbine. Sootblowing of the convection pass increases heat transfer in that region of the boiler, which increases steam temperatures and desuperheating sprays and reduces boiler exit flue gas temperature. For best performance it is important to maintain an optimal balance between the furnace and convection pass heat transfer.

Characteristics of coal ash, ash deposition, slagging and fouling, ash performance indices, boiler sootblowing equipment, effects of sootblowing on unit performance and emissions, and optimization of sootblowing operations are discussed in detail in Appendix VIII.

Traditionally, sootblowers tend to be used at fixed time periods, based on operating experience with the boiler firing a known coal. Determination of optimal sootblower activation using a conventional empirical approach might be difficult. An “optimal” sequence is typically developed on an empirical basis and modified with experience. Also, different operators might have their own “optimal” or favorite sootblower activation sequences. Benefits of sootblowing optimization and maintaining optimal boiler cleanliness (which differs from best cleanliness), as recognized by the electric utility industry, include increased boiler efficiency, improved furnace heat transfer and lower FEGT, reduced NOx emissions, improved unit availability, increased power output, reduced furnace slagging and convection pass fouling, reduced tube erosion and corrosion, reduced sootblower usage, reduced attemperation spray flow rates, reduced sootblower maintenance, and improved SCR catalyst life.

The simplest but still very effective way of dealing with slagging and fouling issues involves modifications to boiler operating parameters, where FEGT is controlled by making changes to the boiler operating parameters such as excess O2 level, secondary air register opening, mill loading patterns, mill out-of-service selection, burner tilt angle, and overfire air register opening and tilt angle. Combustion modifications for slagging and fouling control and results are presented in Appendix VIII for a wall-fired boiler firing high-sulfur Eastern bituminous coal, and a tangentially-fired boiler firing blends of Western and Eastern coals.

The terms sootblowing optimization and intelligent sootblowing are often used interchangeably, but they are not the same. As defined in this report, sootblowing optimization involves determination of the optimal sootblower activation sequence satisfying optimization goal and imposed constraints. The optimal sootblowing sequence
is predominantly time-driven, and is implemented through hardware and some PLC or sootblower control panel programming. For many users, the time-driven optimal sootblower activation strategy is sufficient for improvement of their sootblowing operations.

The intelligent sootblowing involves use of intelligent software (expert system) that satisfies the optimization goal and imposed constraints by making decisions on sootblower activation based on the process data and knowledge base. This is referred to as event-driven sootblower activation. Intelligent sootblowing software operates in the open-loop advisory mode or, preferably, in the closed-loop mode. It provides a means for handling changing optimization objectives, and adapting to changes in fuel quality as well as the maintenance condition of sootblowing equipment. Variations in fuel quality and ash mineral content pose severe challenges to sootblowing due to changes in ash deposition rates and deposit strength. When operating in a closed-loop mode, intelligent sootblowing also eliminates operator variability in selecting sootblowing schedules, and reduces demands on control room operators.

Sootblowing optimization and intelligent sootblowing approaches, developed by the ERC, are based on the minimum data and instrumentation requirements, and involve sootblower characterization testing and application of the knowledge base and expert system. Decisions concerning sootblower activation are based on process data, sootblower characterization data, and cleanliness status of boiler heat transfer surfaces. Cleanliness status is determined by using fuzzy logic either directly through calculation of the surface cleanliness factor, or inferentially, by using indirect measures of surface cleanliness. Both approaches were successfully implemented in the field.

The event-driven sootblower activation is implemented via the intelligent sootblowing code IntelligentClean. This adaptive sootblower activation strategy is needed in cases where there are large variations in fuel quality leading to large variations in slagging and fouling intensity, or other variations such as load changes. The IntelligentClean code can be implemented as the real-time open-loop advisory or in a closed-loop control mode, depending on the sootblower activation frequency. Sootblowing optimization and intelligent sootblowing, field implementation, and results are described in Appendix VIII. Benefits achieved by closed-loop intelligent sootblower control include increased power output (3% increase), lower reheat desuperheating spray flow (30% reduction), more uniform steam temperatures, lower opacity (25% reduction), improved boiler cleanliness, lower NOx, and reduced sootblower activation.

Different approaches to sootblowing optimization and intelligent sootblowing are provided by other vendors. Technical approaches include expert systems, fuzzy logic, artificial neural networks, principal component analysis, first principles analysis, monitoring of temperature differences or conductance, monitoring of ash accumulation by strain gauges, and others. Several vendors have incorporated sootblower characterization into their technical approach, while others depend on a heuristic approach, or human expertise. Some approaches are software-oriented, others depend mostly on improved sootblowing hardware and PLC programming, or a combination of
improved sootblowing hardware and optimization software. Heat flux meters or electrical resistance mapping (ERM) are employed by some vendors to measure waterwall temperatures, calculate cleanliness factor of different waterwall sections, and develop waterwall cleanliness maps. Approaches based on heat flux meters or ERM mapping are expensive.

In conclusion, typical results of a sootblowing optimization or intelligent sootblowing project include improved control of steam temperature, reduced reheat desuperheating spray flow rate, improved unit availability, and higher power generation. The achieved heat rate improvements are typically in the 0.25 to 1% range, which might be insufficient to justify hardware-based sootblowing optimization approaches, especially on a smaller unit. Although difficult to quantify upfront, the improvement in unit availability constitutes the largest financial benefit, and typically justifies the cost of a sootblowing optimization project. Improvement or optimization of the sootblowing activation schedule using existing sootblowing hardware and control systems, is inexpensive and effective and should be considered by all, especially smaller, coal-fired power plants.

**Repowering**

Repowering involves changing the existing boiler and “repowering” the power station using newer, more efficient boiler technologies. It represents an important option for achieving plant and system improvements including reduction of overall system fuel usage and emissions. In a carbon-constrained world, repowering might be a good option for improving efficiency and reducing emissions of existing power plants, especially older units approaching retirement (Stenzel, 1997). The Rankine-Brayton and solid fuel-based repowering options investigated in this project and their characteristics are described in Appendix IX.

**Rankine-Brayton Repowering**

Repowering a Rankine power cycle with a Brayton-Joule (combustion turbine) cycle has the advantage of lower carbon intensity fuel and a considerable increase in output and net plant efficiency in reducing CO₂ emissions. The investigated Rankine-Brayton repowering options included: site repowering, combined cycle repowering, hot windbox repowering, feedwater heater repowering, and supplemental boiler repowering.

The most common type of repowering in the U.S. is combined cycle repowering, where the existing boiler is replaced by a combustion turbine and a heat recovery steam generator (HRSG). This approach can increase the net generating capacity of the unit by about 150-200%, reduce the plant heat rate and CO₂ emissions by up to 30-40%, and also reduce NOₓ emissions. Due to the relatively large capacity increase, this approach is typically considered for older units less than 250 MW with steam pressures up to 1,800 psia.

The hot windbox repowering consists of installing one or more combustion turbines exhausting into the windbox of an existing boiler. It can increase unit capacity by up to 25%, improve efficiency by 10-20%, improve part load efficiency and cycling capability, and reduce CO₂ and NOₓ emissions. It is a partial repowering option where coal is
providing part of the heat input to the boiler while the rest is supplied by the exhaust from the combustion turbine.

In a feedwater heater repowering option, the exhaust gas from combustion turbine is used to heat feedwater in an existing Rankine-cycle power plant. The steam normally used for feedwater heating is expanded through the steam turbine, resulting in higher power output from the steam turbine-generator. This option is attractive because it requires only minimal modifications to the existing steam power cycle. The net unit efficiency at full load operating conditions can be improved by up to 5 to 6%.

Supplemental boiler repowering is similar to the feedwater heater repowering option, except that the combustion turbine exhausts to a HRSG which provides steam to the steam turbine to increase its power output. The economics of this cycle depend on the ability to use the additional steam efficiently in the steam turbine (a steam turbine upgrade might be needed). This option is similar in concept to the biomass-fired boiler option discussed in Appendix XII, except natural gas is used as a fuel instead of biomass.

The main benefits of Rankine-Brayton repowering are improved efficiency of the existing unit, increased power output, and a decrease in CO₂ and other emissions. A reduction in CO₂ emissions is partially due to higher steam combined unit efficiency, and partially due to firing of less carbon-intensive fuel (natural gas) in a Brayton cycle. The downside of Rankine-Brayton repowering is that the coal as a nonvolatile-price fuel is phased out completely or partially, and plant economics is subject to volatility in natural gas prices. The choice of the coal to natural gas proportion depends not only on the price of natural gas, but also on the required reduction in CO₂ emissions from existing units, CCS cost, and the price of CO₂ emission credits or carbon tax.

**Solid Fuel-Based Repowering**

Low-cost opportunity fuels, such as waste coal, petroleum coke, biomass, and waste fuels, present situations where repowering with solid fuel-based technologies is advantageous. Solid fuel repowering options provide increased fuel flexibility, including co-firing of biomass and waste fuels to offset CO₂ emissions. In general, solid fuel repowering requires a larger capital investment when compared to Rankine-Brayton repowering. The solid fuel-based repowering options include atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), gasification fluidized bed combined cycle (GFBCC), and integrated gasification combined cycle (IGCC).

In AFBC repowering, the existing boiler is replaced by a fluidized bed combustor. Commercial AFBC boilers offer good efficiencies at competitive price, and have NOₓ and SO₂ emissions below mandated limits. Bubbling bed or circulating fluidized bed (CFB) technologies are available. Advances in CFB boiler technology in the 150 to 300 MW range make CFB boiler repowering an attractive option to consider. An example of the CFB boiler repowering, including efficiency, emissions, and operation, is presented in Appendix XIV.
In PFBC repowering, an existing boiler is replaced by a pressurized fluidized bed combustor to produce steam for the existing steam turbine and generate hot gases for the new combustion turbine. PFBC designs are available for units ranging from 80-350 MW. The first generation PFBC repowering technology employs a pressurized CFB combustor that produces high-pressure high-excess air gas (also called vitiated or partially used air) stream for the gas turbine. Particulate matter (dust) from the gas stream is removed by ceramic filters. The steam generated from the heat released in the pressurized CFB combustor is provided to the steam turbine, while the combustion turbine exhaust is used for feedwater heating in a HRSG, creating a highly efficient combined cycle system. Plants that have used PFBC technology have lowered plant heat rate by as much as 15% and increased plant output by up to 20%. The other benefits of the PFBC technology are low SO2 and NOx emissions.

A 1½ generation PFBC system increases the gas turbine firing temperature by using natural gas in addition to the vitiated air from the pressurized CFB combustor. The high-pressure gas stream from the pressurized CFB combustor, de-dusted by ceramic filters, is mixed with natural gas and burned in a topping combustor to provide higher inlet temperatures for higher combined cycle efficiency. This power cycle, however, uses natural gas, which is a more expensive fuel than coal. The rest of the system has the same configuration as the first generation PFBC.

In more advanced second generation PFBC systems, called advanced circulating pressurized fluidized-bed combustion (APFBC) combined cycle systems a pressurized bubbling fluidized bed carbonizer is incorporated to convert the feed coal into a low Btu fuel gas and char. The char is burned in a pressurized CFB combustor to produce steam for the existing steam turbine and vitiated air stream for the new gas turbine. Vitiated air is de-dusted by ceramic filters. The hot fuel gas from the carbonizer, de-dusted by ceramic filters, is mixed and combusted with the vitiated air in a topping combustor to provide high-temperature gas to the combustion turbine. The combustion turbine exhaust is used for feedwater heating in a HRSG. An APFBC system has combined cycle efficiency higher than 42%, while operating on low-cost low-rank coal and opportunity fuels, resulting in 30% lower specific coal consumption and CO2 emissions compared to the exiting power plant. Also, NOx, SOx, and PM emissions are lower.

GFBCC is a hybrid coal-fueled system employing a pressurized CFB partial gasifier, and an atmospheric CFB combustor. The pressurized CFB partial gasifier operates at elevated pressure in a mild gasification mode that produces syngas and char. Syngas fuels the new gas turbine, while char is burned in a pressurized CFB combustor to generate steam for the existing steam turbine. The syngas is cooled in a syngas cooler before being de-dusted by sintered metal filters. Clean syngas is combusted in a topping combustor providing high-temperature gas for the combustion turbine. The gas turbine exhaust is used as combustion air for the CFB. This provides a convenient way for recovering heat from the gas turbine exhaust and increasing efficiency of the power cycle. The GFBCC represents one the cleanest, most efficient ways of using coal for electric power generation.
IGCC repowering is the most expensive and complex repowering option. IGCC is one of the most efficient and cleanest technologies for coal-based electric power generation where a gasifier converts a solid fuel to a gaseous fuel (syngas) for the new combustion turbine. Steam for the existing steam turbine is produced by using heat from a syngas cooler, and by recovering heat from the gas turbine exhaust in a HRSG. High efficiency is obtained through system integration to efficiently use and recover waste heat. IGCC repowering can reduce plant heat rate by up to 30%, with a resulting decrease in CO₂ emissions. Also, the IGCC system, based on the oxygen-blown gasifier, is very suitable for implementation of CCS technology due to a low volume of gas that needs to be treated. The gasification process can also be used to produce other products, accelerating the payback of the initial capital investment. IGCC can be used for repowering 50-100 MW steam turbine-generators, and provide an additional 150-250 MW of the combustion turbine capacity. Similar to combined cycle repowering, capacity increase is relatively large compared to the size of the existing unit.

**Task 2: Identify and Characterize Cost-Effective Options for Emissions Reduction**

Options for improving performance and reducing emissions are summarized in Task 1 of the report with details provided in Appendices I to IX. Task 2 is focused mainly on reduction of CO₂ emissions from coal-fired power plants.

To put CO₂ emissions from existing power plants in prospective, information was gathered on historic and current CO₂ emission levels from the end-use and power generation sectors in the U.S. According to the Energy Information Administration (EIA), 8,320 millions metric tons (8.32 Gt) of CO₂ were emitted from end-use and electric power sectors in the U.S. in 2005 (see Figure 12). The end-use sector was responsible for 71% of the energy-related CO₂ emissions, while the electric power sector emitted 29% of the CO₂ emissions, 23% of that from coal.

![Energy-Related CO₂ Emissions](image_url)

**Figure 12: Energy-Related CO₂ Emissions in U.S. from 1949 to 2005**
In 2004, a total of 27 Gt of CO₂ was emitted worldwide from burning fossil fuels. Compared to previous years, CO₂ emissions from industrialized regions, such as North America and Europe decreased, while CO₂ emissions from regions experiencing large economic growth (such as Asia) sharply increased. In 2004, U.S. contribution was about 22%, European about 17%, while Asian contribution was about 36% of total CO₂ emissions.

Although global climate change has received considerable attention over the past few years, the magnitude of the problem is not yet well understood. The effect of proposed solutions on energy security and economy is, unfortunately, understood even less. In the last 50 years, environmental regulations beginning with the 1955 Air Pollution Control Act and followed by The Clean Air Act of 1963, The Clean Air Act Amendments of 1969-1970, 1977 and 1990, and others, addressed pollutants (NOₓ, SOₓ, PM, and most recently Hg) which are present in the flue gas in very low concentrations (ppmv of µg/Nm³). After 50 years and billions of dollars invested in air pollution controls, this effort is still on-going. For example, according to EIA Form EIA-767, in 2005, only about 100,000 MW of coal-fired capacity was equipped with FGDs.

CO₂ concentration in flue gas is on the order of 15% (wt) or higher (depending on the coal rank). This is approximately four orders of magnitude (10,000 times) higher compared to NOₓ and Hg. Clearly, we are facing a problem of unprecedented proportions and cost. An early U.N. estimate places a price tag on CO₂ mitigation at $20 trillion worldwide, with the actual cost most likely to be much higher. To be effective, CO₂ emissions need to be reduced from all sectors and across the globe.

This section of the report is concerned with CO₂ reduction from coal-fired power plants, with an understanding that large reductions are possible (and necessary) in the end-use sector. The three main paths to CO₂ capture from coal-fired power plants are presented in Figure 13. Post-combustion CO₂ capture and pre-combustion denitrogenation (referred to as oxy-fuel combustion) options were investigated in Task 2 of the project, and their development status and effect on plant efficiency and capacity are presented in Appendices X and XI.

![Figure 13: Three Main Paths to CO₂ Capture](image-url)
Oxy-Fuel Combustion

Oxyfuel combustion, also referred to as pre-combustion denitrogenation, represents one of three main paths to CO₂ capture from coal-fired power plants. A process schematic, utilizing cryogenic Air Separation Unit (ASU) and wet recycle before SO₂ removal, is presented in Figure 14.

![O₂/CO₂ recycle (oxyfuel) combustion capture](image)

**Figure 14:** Schematic Diagram of Oxyfuel Combustion Process
Employing Cryogenic ASU

A portion of the flue gas leaving the oxy-fuel boiler is recycled back to the boiler to limit flame and flue gas temperatures and furnace heat fluxes to the level comparable to air combustion.

The air in-leakage has a negative effect on efficiency of the oxy-fuel cycle, CO₂ recovery, and CO₂ removal cost. For new boilers, air in-leakage can be greatly reduced by boiler design, while for retrofits maintaining low air in-leakage might be a challenge. One of the proposed solutions involves use of captured CO₂ as a sealing fluid.

The first generation of oxyfuel boilers will use external recycle and will be similar in size and design to existing boilers. The second generation of oxyfuel boilers will be smaller and will use internal recycle. The first and second generation of oxyfuel boilers will depend on cryogenic oxygen (air) separation technology (cryogenic ASU). Although this is a mature technology, the performance penalty for O₂ production is large. With cryogenic ASU technology, optimal O₂ purity is in the 95 to 97.5% range.

The third generation of oxyfuel boilers is likely to employ Oxygen Ion Transport Membrane (OTM, or ITM) technology which is currently in early stages of development. The advanced OTM boiler concept, being developed jointly by Praxair and Alstom Power, has the potential to drastically reduce air separation requirements. Currently, a cryogenic ASU consumes more than half of auxiliary power, and reduces net unit efficiency by approximately 6.5%-points.
The flue gas from the oxy-fuel boiler will contain up to 75 to 85% by volume CO₂ (on dry basis), and also oxygen, water vapor, and residual quantities of argon and nitrogen (which mainly enter the system with the undesirable air in-leakage), and oxides of sulfur and nitrogen formed during combustion process. These residual gases make it difficult to raise the CO₂ concentration in dry flue gas to more than 90% by volume. Although specifications for CO₂ purity required for sequestration currently do not exist, it is expected that required CO₂ purity will be higher than 95%. To achieve this purity level, one-stage or two-stage partial condensation is needed.

The most economical and efficient solution of CO₂ separation would be to compress the dried flue gas to about 1,500 psia and store it underground. In this case, any contaminants such as O₂, NOₓ and SOₓ would be stored with the CO₂, which might possibly lead to undesirable processes in the geological storage locations and pipeline corrosion. Considering this possibility, NOₓ and SOₓ might have to be removed before CO₂ is sequestered.

A two-stage CO₂ purification process, developed jointly by Air Products, Doosan Babcock, and Imperial College, removes NOₓ, mercury and arsenic, and converts SO₂ to SO₃. Dilute sulfuric acid is then removed by the water treatment system. Any remaining NOₓ is converted to nitric acid, which is discharged to the water treatment system. In the second stage of the process, CO₂ is dried (water is removed in a flue gas condenser, or condensing heat exchanger) and inerts (N₂, Ar, and O₂) are separated, resulting in a high-purity CO₂ stream. This stream is compressed to either 1,500 or 2,200 psia and transported to the sequestration site via pipeline where it is stored underground. The energy stored in the compressed CO₂ fluid represents a net loss to the power plant of about 8% of gross power, or 3 to 3.5%-points in efficiency.

To improve thermal efficiency of the oxy-fuel power plant, energy (heat) integration of the ASU, flue gas cooler and condenser, and CO₂ compression train (adiabatic compressor with after-cooler) with the oxy-fuel boiler and steam turbine cycle is needed to utilize portion of compression, sensible and latent heat from these processes and improve efficiency of the power cycle. Examples of heat integration are presented in Appendix X.

Currently a number of oxy-fuel demonstrations are in progress as technology is developed from laboratory to pilot scale. Figure 10-32 in Appendix X shows historical progression of the scale of oxy-fuel pilot plants and demonstrations.

Additionally, research, regulatory, technology development, and deployment targets are presented in Appendix X. It is expected that regulatory framework will be established by 2014 to allow permitting for demonstrations to be operating by 2020. It is also expected that gas cleaning technology will be proven by 2014 to meet regulatory requirements for CO₂ transport and storage, and that ITM membranes will be developed by 2016 to reduce parasitic energy loss due to air separation and improve net unit efficiency. Second generation oxy-fuel boilers are expected to be in service after 2020. Projected oxy-fuel technology development phases are presented in Figure 10-33 in Appendix X.
In summary, oxy-fuel combustion technology is now approaching the pre-commercial demonstration stage with a number of demonstration plants under construction worldwide. Operational experience through demonstration is critically important to oxy-fuel commercial plants with CCS.

**Post-Combustion CO₂ Capture**

Post-combustion systems separate CO₂ from flue gases produced by combustion of primary fuel in air. The purpose of CO₂ capture is to produce a concentrated stream of CO₂ at high pressure that can readily be transported to a storage site.

Conventional coal plants are faced with a difficult task of capturing post-combustion CO₂ from flue gas at atmospheric pressure. The concentration of CO₂ in flue gas from a pulverized-coal (PC) power plant is typically less than 15% (by volume), with most of the rest being nitrogen from the air used to support combustion. Nevertheless, 80–95% of the CO₂ can potentially be removed from the flue gas by post-combustion capture systems, with the exact percentage dependent mainly on economic trade-offs.

A schematic of a post-combustion CO₂ capture process is presented in Figure 15. The boiler and most of the flue gas treatment system are the same as in a conventional coal-fired power plant. Following treatment in pollution control equipment to remove SO₃, NOₓ, and PM, CO₂ is separated from nitrogen. The separated CO₂ is dried, liquefied and compressed to approximately 2,200 psia for transport to a sequestration site, or use for enhanced oil recovery.

![Figure 15: Schematic of Post-Combustion CO₂ Capture](image)

The basic technologies for post-combustion CO₂ capture include the following: (1) absorption of CO₂ in a physical or chemical solvent followed by regeneration of the solvent for production of CO₂, (2) physical or chemical adsorption of CO₂ on a solid adsorbent followed by regeneration of the sorbent to produce CO₂, and (3) selective permeation of CO₂ through a porous or non-porous membrane. For any one of these technologies to be feasible, there must be some form of economic or legal incentive.
Legal incentives are expected to arise from restrictions on CO₂ emissions resulting from measures such as the Kyoto protocol that are gaining worldwide support.

For a modern pulverized coal (PC) fired-power plant, commercially available post-combustion capture systems would typically employ an organic solvent such as monoethanolamine (MEA). Other chemical-based options for absorption are under consideration, including advanced amine solvents, amine-enriched sorbents, aqueous ammonia (NH₃) solutions and non-amine reagents. Commercially-viable CO₂ scrubbing technologies are based on low-temperature CO₂ absorption on a solvent in an absorber, and regeneration of the solvent in a stripper at higher temperature to release captured CO₂ and produce a CO₂-rich stream. The heat required for solvent regeneration is supplied by steam extracted from the low-pressure (LP) steam turbine. Steam extraction, combined with other parasitic loads, such as CO₂ compression, has a significant negative effect on power output and efficiency of the power plant.

Significant improvements in CO₂ scrubbing technology have been made in the past five to ten years, especially in reducing the energy penalty for CO₂ capture. However, negative effects of commercially available CO₂ scrubbing technology on plant efficiency and capacity are still large, as illustrated in Figures 16 and 17 where effects of MEA scrubbing on net power output and plant efficiency are presented as functions of the CO₂ capture level.

![Figure 16: Effect of CO₂ Capture Level on Net Power Output](image-url)
The results show that significant savings can be achieved by reducing the CO₂ capture requirement from 96 to 90%. This is especially true for the Cost of Electricity (COE), which is reduced by 45% (see Figure 18). (Economic analysis was performed by using a replacement power cost of 6.40 ¢/kWh, 2001 study results were escalated to 2006 dollars, while variable O&M cost includes SO₂ credit of $608/ton, Ciferno, 2007). Results show there is no “sweet spot” and no optimal CO₂ capture level, at least not in terms of the COE.

### Economic Results

![Figure 18: Cost of Electricity vs. Percent CO₂ Capture](image)
The key challenges for retrofitting post-combustion CO₂ capture to existing power plants include the following: (1) availability of steam for solvent regeneration, (2) major equipment modifications or redundancy, (3) high-efficiency desulphurization equipment is required to reduce SOₓ to the 10-30 mg/Nm³ level required by ammine scrubbers, (4) space limitations (many acres are needed for current scrubbing technologies), (5) replacement power needed to offset power loss due to CO₂ scrubbing and maintain base load output, (6) scheduling outages for CO₂ retrofits, (7) post-retrofit dispatch implications due to increased COE (dispatch of scrubbed vs. non-scrubbed units), (8) retrofit triggering NSPS review, and (9) uncertainties concerning proposed legislation.

In addition to improvements in CO₂ separation (capture), the area requiring equal attention is CO₂ liquefaction and compression, where improvements are needed to reduce compression work (currently responsible for about 3 to 4%-point reduction in power plant efficiency). Heat and system integration are needed to reduce CO₂ compression and capture costs. The ERC is working actively in the area of heat integration.

**Biomass Co-Firing**

A typical subcritical bituminous coal-fired power plant emits nearly three tons of CO₂ for each ton of coal burned. On an energy basis, this amounts to about 220 lb CO₂/MBtu. While combustion of biomass produces about the same level of CO₂ as coal on an energy basis (about 220 lb CO₂/MBtu for wood), biomass is considered CO₂-neutral (no net CO₂ increase) relative to fossil fuel combustion. However, biomass and biofuels can be considered renewable sources of energy as long as they are based on sustainable biomass production. For biomass to be truly CO₂-neutral, an equivalent level of new biomass growth is needed to replace biomass combustion. Other issues, complicating the role of biomass in terms of global climate change include the energy required for its planting, growing, harvesting, transporting and processing, as well as decomposition effects which release other greenhouse gases, such as methane.

Biomass feedstocks can be classified as woody and herbaceous. Woody feedstocks include mill residues (bark, sawdust, planer shavings, chips), forestry residues, and urban waste such as pallets, railroad ties, utility poles. Herbaceous feedstocks include crops (agricultural wastes, switchgrass, miscanthus, reed canary grass), crop residues (straw, alfalfa, corn stover, rice straw), and production materials (bagasse, corn cobs, rice, oat and nut hulls, fruit pits, trimmings). Biomass resources, conversion technologies, and use of biomass for power generation are described in Appendix XII.

**Biomass Properties**

The composition of biomass fuels is very different from coal. While coal composition is relatively consistent, biomass fuels often exhibit considerable variability in fuel characteristics. Compared to bituminous coals, both woody and herbaceous biomass fuels have a significantly higher moisture content (up to 50-60%), a significantly lower carbon content (about 3 times lower), and a significantly higher volatiles content (about 2 times higher). The volatiles-to-fixed carbon ratio (V/FC) is high, indicating that biomass fuels burn close to the burner, resulting in hotter furnace waterwalls and lower FEGT. The V/FC ratio for woody biomass fuels is about 7.5 to 5.5 times higher compared to
bituminous and sub-bituminous coals, respectively. The sulfur content of biomass fuels is very low. Most biomass fuels (excluding straws) are very low in chlorine content. However, variation in nitrogen and ash content can be large. In general, biomass fuels have lower ash fusion temperature compared to coal, which promotes ash deposition.

Also, the mineral content of coal and biomass fuels is very different. In contrast to coals where sodium predominates, biomass alkali tends to be significantly higher and predominantly potassium-based. Straws, other grasses and herbaceous species, younger tissues of woody species, and other annual biomass contain more potassium compared to mature and urban wood. Alkali content varies considerably among biomass fuels. A fouling index, based on the mass of alkali metal oxides \((K_2O + Na_2O)\) per MBtu heat input to the furnace, can be used to assess the fouling propensity of a fuel. At index values above 0.4lb/MBtu, plant experience and field tests have shown that significant fouling of the boiler convective section is probable. For index values in excess of 0.8 lb/MBtu, severe fouling is to be anticipated. Young biomass materials have index values in excess of 4.7 lb/MBtu, whereas most coals have relatively low values, generally less than 0.47 lb/MBtu. While an indicator of potential problems, the fouling index needs to be combined with field experience taking into consideration boiler operating conditions to evaluate the impact of a fuel on a particular boiler.

Much of the alkali in biomass is in forms susceptible to vaporization. Vaporization of potassium and subsequent chemical reactions are responsible for much of the fouling, sulfation, corrosion, and silicate formation found in biomass boilers. Alkaline earth metals (K, Na, Ca, and Mg) present in the biomass are in forms that are less likely susceptible to vaporization. Therefore, ligneous materials, such as wood, with ash containing large fractions of calcium, pose far less fouling problems than herbaceous materials, such as straws and grass. Chlorine can be an important facilitator in fouling, leading to the condensation of alkali chlorides on boiler heat transfer surfaces, and promoting formation of alkali sulfates. Deposit formation depends on the release and chemistry of chlorine, sulfur, aluminum silicates and alkali during combustion.

The impact of biomass co-firing on ash deposition depends largely on the chemistry and fusion behavior of the coal ash and the co-firing ratio. Rates of ash deposition from biomass fuels can greatly exceed or be considerably less than those from firing coal alone, Figure 19. Deposition rates from blends of coal and biomass are generally lower than indicated by a direct interpolation between the two rates. This reduction occurs primarily because of interactions between alkali (mainly potassium) from the biomass and sulfur from the coal (Project No. SES6-CT-0200007, 2006). Therefore, co-firing high-potassium biomass with low-sulfur coals might be challenging.
The as-received HHV of woody and herbaceous biomass fuels is about 2.5 times lower compared to bituminous coals. Considering a 5-fold difference in density, the overall energy content of biomass is roughly one tenth that of coal. Consequently, co-firing biomass at a 10% heat input rate results in volumetric coal and biomass flow rates of comparable magnitudes. Therefore, demands on biomass shipping, storage, and on-site handling are disproportionately high compared to its heat contribution. Although usually not a problem during biomass co-utilization demonstration tests, these demands could represent significant logistic challenges for continuous co-firing of biomass.

Unlike pulverized coal, biomass is quite irregular in shape. This is true even for sawdust. This variation and irregularity in particle shape and size affects particle aerodynamics, which in turns affects particle mixing and contact with oxygen, the particle residence time, char burnout, and LOI. It is generally unfeasible (and unnecessary) to reduce biomass to the same size or shape as coal. In many demonstration plants, biomass firing occurs with particles that pass through a ¼" mesh, with size distribution dominantly less than about 1/8”.

**Applications**

The three main concepts for biomass co-firing in PC-fired boilers include direct co-firing, indirect co-firing, and separate firing (also called parallel firing). All of these concepts have been implemented either on a demonstration or a fully commercial basis, and each with its own particular merits and disadvantages. Direct co-firing is the most straightforward application, most commonly used and lowest cost ($50-$300 per kW of biomass capacity). Biomass fuel and coal are burned together in the same furnace, using the same or separate mills and burners depending on the biomass fuel characteristics. Direct co-firing can be further classified into the following three groups: direct injection, co-milling, and reburning.

In indirect co-firing, a biomass gasifier is used to convert solid biomass materials into a fuel gas, which can be burned in the same furnace as coal. This option offers the
advantages that a wider range of biomass fuels can be used (e.g. difficult-to-grind biofuels), and that the fuel gas can be cleaned and filtered to remove impurities before it is burned in the utility boiler. Experience with this option is rather limited. A separate biomass boiler can be used to generate steam to be used in the steam turbine of the existing coal-fired power plant. This is similar to the supplemental boiler repowering option.

Operating costs for biomass are typically higher than for coal. The most important factor is the cost of fuel, with energy crops suffering large economic disadvantages relative to residues and wastes. Even if the fuel is free at the point of its collection, transportation, preparation, and on-site handling increase the cost per unit of energy such that it rivals and sometimes exceeds the cost of coal. In general, biomass co-firing is commonly slightly more expensive than dedicated coal systems. If there were no motivations to reduce CO₂ emissions, biomass co-firing would be difficult to justify. However, when compared to other renewable energy sources, biomass co-firing is generally significantly cheaper. Therefore, it is one of the best short-term and long-term solutions to reducing greenhouse gas emissions from power generation.

Biomass co-firing has been successfully demonstrated in over 150 installations worldwide for most combinations of fuels, boiler types (stoker, cyclone, bubbling fluidized bed and CFB, tangentially- and wall-fired), and sizes (50 to 700 MW). About a hundred of these demonstrations have been in Europe. In the U.S. there have been over 40 commercial demonstrations, with the remainder mainly in Australia. The proportion of biomass has ranged from 1 to 20%. A broad combination of fuels, such as residues, energy crops, herbaceous and woody biomasses, have been co-fired. Cyclone boilers can co-fire wood up to as high as 15%. PC-fired boilers can co-fire wood in the range of 2-10%. Most of the known biomass co-firing experience in the U.S. has been in coal-fired cyclone and stoker boilers, where long residence times allow combustion of coarse particles. In contrast, comparatively little biomass co-firing has been performed in PC-fired utility boilers, which are dominant in U.S. power generation.

The experience with biomass co-firing in PC-fired boilers has demonstrated that co-firing woody biomass generally results in a modest decrease in boiler efficiency. The effect on capacity can be positive or negative, depending on site-specific conditions. The typically high biomass moisture content, compared to coal, has a negative effect on boiler efficiency, and increases the volume of biomass that needs to be handled. A considerable reduction in SO₂, NOₓ and mercury emissions was typically achieved, except for nitrogen-rich switchgrass where co-firing increased NOₓ emissions. Though herbaceous biomass have been co-fired in several plants worldwide, their higher content of inorganic matter results in higher slagging and fouling. Therefore, co-firing herbaceous fuels tends to be more difficult and costly than other fuels. Typical issues encountered with biomass co-firing include fouling, corrosion, fuel (carbon) conversion, formation of striated flows, impacts on SCR operation, and fly ash utilization. These issues and biomass co-firing options are discussed in detail in Appendix XII.
The high moisture content of biomass fuels can be reduced by thermal drying. A low-temperature drying process, developed by ERC and GRE for drying of high-moisture coals, can also be used for biomass drying. This achieves higher efficiencies and reduces the volume of biomass that needs to be co-fired in the boiler. Biomass drying experiments conducted at the ERC show that wood chips can be dried in a fluidized bed dryer (FBD) in less than 30 minutes from the initial moisture content of 64% to 1.5 to 2.5% final moisture using a low-grade heat rejected by the power plant. Such moisture reduction doubles HHV of the biomass, increases the proportion of co-fired biomass on an energy basis (which reduces CO\textsubscript{2} emissions), reduces energy losses due to evaporation of biomass moisture in the boiler furnace, improves the boiler and plant efficiency, and makes the biomass co-firing process more economical. Following drying in a FBD, dried biomass can be mixed with coal, or injected separately into the boiler furnace.

**Task 3: Develop Analysis Methodology and Tools**

Thermodynamic analysis of commercially available heat rate improvement technology options, technologies nearing commercialization stage, and newly developed technologies and concepts for efficiency improvement and emissions reduction of older coal-fired power plants firing Illinois coals was conducted using analytical models developed in this the project, as well as existing models developed by the ERC.

Spreadsheet-based first principles models, based on conservation of mass and energy and equilibrium thermodynamics were developed to allow modeling of unconventional system modifications. These models included combustion calculations, heat transfer analysis, calculation of fan and mill power, and equilibrium-based condensation of sulfuric acid and moisture from the flue gas. Model results were, wherever possible, compared and verified against test or plant operating data, or results from the literature. Also, existing models, including the HEATRT, RPHMT, and FBD codes developed by the ERC, were used in the analysis. Analysis methodology, models, and codes used are described in the Experimental Procedures (Technical Approach) section of the report.

**Task 4: Analyze Effect of Planned Outages and Hardware Upgrades on Performance and Emissions and Recommend Options for Further Improvements for Two Power Plants Firing Illinois Coals**

Operating data collected at two power stations firing Illinois coals, before and after outages, were analyzed to determine the effect of scheduled outages and hardware upgrades on performance and emissions. Results, findings, and recommendations for further improvements are summarized below. Details are presented in Appendices XIII and XIV.

**Power Plant Site 1**

The Power Plant Site 1 (PPS1) is a 1976 vintage front wall-fired Riley balanced draft subcritical boiler designed to fire washed Illinois coals containing 16 to 18% moisture. Three double-ended ball tube mills provide coal to 24 CCV\textsuperscript{R}-DAZ burners arranged in four elevations. The boiler provides steam to a single-reheat steam turbine, rated at 384 MW at 2,414 psia throttle pressure, and 1,000°F main steam and reheat steam temperature, and 1” Hg Abs. condenser pressure.
A major unit upgrade was conducted in two phases. The first phase of the upgrade was performed during a November 2007 outage to improve boiler reliability, provide fuel flexibility, and increase unit efficiency and capacity. New radiant superheater, reheater, primary superheater, and economizer were installed, and boiler sootblowers were upgraded. One of the mills was replaced with a new, larger capacity mill to provide larger steam capacity needed for the upgraded steam turbine. Dynamic classifiers were added to coal mills to improve coal fineness. The pollution control system was upgraded including installation of a new, larger ESP for enhanced PM control and control of mercury emissions by activated carbon injection, and a new catalyst in the SCR reactor for enhanced NOx control. Turbine upgrades included new high-pressure (HP) and intermediate-pressure (IP) steam turbines to increase turbine capacity and improve efficiency of the HP and IP sections. Also, the plant control system was upgraded, with the addition of a new burner management system to reduce CO emissions and a combustion optimizer to improve performance and reduce emissions.

The second phase of the unit upgrade included construction of new wet scrubber for control of SO2 emissions, upgrade to the low-pressure (LP) turbine, and new ID fans to overcome current ID fan limitations. These upgrades were performed during a winter 2009 outage with the unit scheduled to be back in service in March 2009.

PPS1 was visited in July 2008 to collect detailed plant operating data, information on unit design, hardware improvements, performance, emissions, fuel quality, any operating and environmental constraints, and explore opportunities for performance improvement and emissions reduction. Two months of plant operating data preceding and following the November 2007 outage were collected and analyzed to determine improvements achieved in the first phase of upgrade. Results are presented in Appendix XIII. The winter 2009 post-outage data was collected in April and May with results also included in Appendix XIII.

Following phase one of the unit upgrade, tests were performed by professional testing companies to determine distribution of coal in coal pipes, coal fineness, HP and IP turbine efficiency, and boiler and turbine cycle performance. Test results show that with a dynamic classifier in service, coal flow rates in coal pipes are relatively well balanced; however, with the dynamic classifier out of service, large deviations were measured. Coal fineness needs to be improved because the percentage of coal retained on a 50 mesh screen is high (about 5% when it should be 0.5 to 1%). The percentage of coal passing a 200 mesh screen is low (57 to 67%), with higher values corresponding to operating conditions when the dynamic classifier was in service.

Results of a boiler performance test, conducted at about 80% MCR (due to ID fan limitations), show good agreement between design and test values of boiler efficiency. As previously discussed, the boiler was modified to increase its steaming capacity and match it with the upgraded steam turbine capacity. Test results show that the upgraded boiler design provided 28% increase in boiler thermal duty at 80% MCR.
Results of turbine efficiency tests show that advanced blade design and other design features employed in the new HP and IP turbines resulted in 5 to 6%-point improvement in HP and IP turbine efficiencies. Higher boiler thermal duty, combined with higher HP and IP efficiencies, resulted in approximately 80 MW increase in gross turbine power output. Due to the superheat desuperheating spray flow limitations, the FGR fan could not be used during the test resulting in lower reheat steam temperature, lower gross power output, and higher turbine cycle heat rate compared to design values.

Comparison of the pre- and post-outage performance shows that the average gross turbine cycle heat rate (HRcycle) at full load (360 MW gross) is approximately 2% lower compared to the pre-outage value. Correcting the post-outage value of HRcycle for the hot reheat steam temperature increases this difference to 2.7% (see Figure 20), which is equal to the difference between original and new design values. Results also show that pre-outage values of HRcycle are 4 to 5% higher compared to the original design values. Most of this difference can be attributed to equipment degradation over more than 30 years of service.

The post-outage value gross unit heat rate (HRgross) at full load is, on average, 1.3% lower compared to the pre-outage value. Correcting HRgross for the hot reheat steam temperature increases this difference to approximately 2.2%. The post-outage value of net unit heat rate (HRnet) at full load is higher compared to the pre-outage value, mostly due to higher station service requirements, which have, at full load conditions, increased by 30% compared to the pre-outage values. This increase in auxiliary power consumption is attributed to new larger primary air (PA) fans which were installed during the November 2007 outage. Larger PA fans were installed to provide for fuel flexibility, i.e., burning of low-rank, high-moisture coals. When burning Illinois coals, the PA fan capacity is too high, and fans need to be throttled resulting in unnecessary power losses and high station power use.

![Figure 20: Pre- and Post-Outage Values of Turbine Cycle Heat Rate](image-url)
Based on analysis of the pre- and post-outage plant data and performance, it is recommended that drying of high-moisture washed Illinois coals burned at PPS1 be considered. Moisture content of washed coals can be reduced by employing a low-temperature coal drying system and fluidized bed dryer technology described in Appendix I. Drying coal to 8% moisture content will improve net unit heat rate by approximately 2%, and will also improve coal grindability. Also, installation of VFDs is recommended not only to reduce PA fan power requirements and improve net unit heat rate, but also to ensure stable PA fan operation at loads lower than 80% MCR. Advanced air preheating should also be considered to maintain high APH cold end temperature, reduce acid deposition, push ABS deposition zone closer to the APH cold end for easier cleaning, and improve unit performance by up to 1%. Sootblowing optimization should be employed to maximize the hot reheat steam temperature which has a significant effect on unit performance and capacity. Heat recovery from the flue gas can also be considered for drying of wet biomass fuels if biomass co-firing were implemented at PPS1 to reduce CO₂ emissions. Biomass drying is described in Appendix XII.

Power Plant Site 2

Power Plant Site 2 (PPS2) is comprised of two units. Unit A was repowered in 2003 by replacing three original small boilers with a 120 MW Circulating Fluidized Bed (CFB) boiler. The CFB provides steam to three 1961 vintage 33 MW steam turbines, and is rated at 875 psig and 905°F. The CFB boiler was designed to burn moderate-moisture, moderate-sulfur, low-Btu mine and coal preparation wastes. The design value of boiler efficiency is approximately 85%. As presented in Figures 21 and 22, SO₂ and NOₓ emissions were greatly reduced by the repowering.

Figure 21: SO₂ Emissions and Heat Input Before and After Repowering
SO₂ removal is achieved by sulfur-limestone reactions in the bed, which result in formation of calcium sulfate. The ideal reaction temperature range is 1,500 to 1,700°F. There is little limestone reaction when the bed temperature is below 1,500°F or above 1,700°F. An SNCR, employing injection of anhydrous ammonia, is used for control of NOₓ emissions. Particulate emissions are controlled by a baghouse.

The actual fuel moisture is higher and HHV lower than design values, resulting in lower bed temperatures compared to design, which affects SO₂ removal efficiency in the CFB. To raise bed temperature and improve SO₂-limestone reaction, some of the evaporative wingwalls were removed from the furnace. A mixture of coal slurry and Illinois coal was burned after the outage to increase bed temperature, and improve sulfur capture in the bed. This has raised bed temperature by about 50°F, but has increased NOₓ emissions, and plant operating cost. To maintain the NOₓ emission limit, ammonia injection rate was increased, resulting in increased ammonia slip and increased rates of ABS deposition (and corrosion) of heat transfer tubes in the tubular APH. A polishing SCR will be installed upstream of the APH to make use of the ammonia slip.

PPS2 was visited in September 2008 to collect plant operating data, information on unit design, outage activities, performance, emissions, fuel quality, operating and environmental constrains, and explore opportunities for performance improvement and emissions reduction for both Units A and B. Two months of plant operating data preceding and following the spring 2008 outage were collected for Unit A and analyzed to determine the effect of the outage on performance and emissions. Results are presented in Appendix XIV.
Comparison of the pre- and post-outage operating data shows that after the outage the final superheater steam outlet temperature has, for reduced loads, increased to values close to the design value. Before the outage, outlet steam temperature was significantly lower. Also, feedwater temperature into the economizer has increased at reduced loads. Both have a positive effect on boiler and turbine cycle efficiency. Data also show that gross turbine power output for turbines 1 and 2 has slightly increased compared to the pre-outage conditions. For turbine 3, which was overhauled during the outage, the increase in power output was about 2 MW, or 6%.

Improvements in performance of the boiler, boiler auxiliaries, and steam turbines achieved during the outage resulted in improvements in plant performance; boiler heat input was reduced by approximately 3.7% compared to the pre-outage conditions. The gross unit heat rate at 100 MW has improved by 450 Btu/kWh, or 3.7% (see Figure 23), which is in agreement with the reduction in boiler heat input. The improvement in net unit heat rate is higher due to lower auxiliary power use. However, because auxiliary station use is not in the plant database, the net unit heat rate could not be calculated.

Stack opacity was reduced from the pre-outage average value of 10% to less than 2% after the outage because leaking or torn bags in the baghouse were replaced with the new bags. The NOx concentration at the SNCR outlet remained constant, however the SNCR ammonia injection rate increased by approximately about 30%. The SO2 emission rate remained approximately constant.

Based on analysis of pre- and post-outage operating and performance data, it is recommended that moisture content of the carbon slurry can be reduced by employing the low-temperature fluidized bed dryer technology described in Appendix I. The heat needed for coal drying will be recovered from the flue gas. This will result in lower plant operating costs, lower SO2 emissions, and restored CFB boiler performance.

![Figure 23](image-url): Gross Unit Heat Rate vs. Gross Power Output, Corrected to 1.5” Hg Abs
because steam turbines at Unit A are in a good shape with approximately 20 years of useful life remaining, turbines 1 and 2 should be rebuilt to improve their performance. Rebuilding of turbine 3 has improved its power output by about 6%. The same or similar maintenance should be performed at the other two turbines at the next outage. In the summer, the temperature of the plant cooling source is significantly higher compared to winter, increasing condenser pressure by 2” Hg Abs., reducing full load gross power output by 2.2%, and increasing net unit heat rate by 2.6%. For reduced loads, the heat rate penalty is considerably higher. The use of helper cooling towers should be considered during time periods when sink temperature is significantly warmer compared to the design cooling water temperature. Drying of wet biomass fuels should be considered if biomass co-firing were implemented at PPS2 to reduce CO₂ emissions. Biomass drying is described in Appendix XII.

Unit B is a 1969 vintage Babcock and Wilcox positive-draft cyclone-fired radiant subcritical boiler with four slagging cyclones, supplying steam to a single reheating GE steam turbine rated at 173 MW at 1,005°F main and reheating steam temperature. The boiler is equipped with an SCR, ESP, and wet scrubber for NOₓ, PM, and SO₂ emissions control. Although not a part of the project scope, analysis of the pre-and post-outage performance and operating data of Unit B was included in the study because of some unique unit upgrades performed in the fall 2008 unit outage, including turbine L-0 blade upgrade, turbine seal replacement, top feedwater heater replacement, main steam condenser retubing, replacement of a significant portion of the boiler water walls, and complete APH replacement. Results concerning the spring and fall 2008 outages are presented in Appendix XIV.

CONCLUSIONS AND RECOMMENDATIONS

As concerns about the effect of anthropogenic emissions of CO₂ on global climate increase, efficiency improvement, as the only practical option capable of immediate reduction of CO₂ emissions, has become a key concept for the choice of technology for new plants and upgrades of existing power plants. Early reduction in CO₂ emissions is of paramount importance because the sooner CO₂ emissions reductions start, the smaller the future reduction and the lower the cost to stabilize CO₂ concentration in the atmosphere at desired levels. Although new, more efficient power-generating technologies and CO₂ removal technologies are nearing commercialization, significant market penetration will take some time. Estimates range from 2030 to 2050 and beyond. Improving efficiency of existing power plants and newly build generation (approximately 140,000 MW by 2030) remains the first logical, inexpensive and necessary step. Also, the efficiency of a coal-fired power plant will have a strong effect on the cost of carbon capture. With higher efficiency, the flow rate of flue gas that has to be treated will be lower, resulting in a smaller, less expensive CCS system.

Part 1: Performance Improvement and Emissions Reduction
Cost-effective commercially-ready options, newly developed technologies and concepts, and technologies nearing commercial application for improving efficiency and reducing the cost of pollution control for existing power plants firing Illinois coals were
investigated and analyzed in the first part of the study to quantify achievable performance improvements and emissions reductions. These options include the following:

Recovery and Utilization of Heat from Flue Gas
The amount of heat in the flue gas is too large to just be discharged into the atmosphere. Recovered heat can be used for air preheating, feedwater heating, reduction of moisture content of high-moisture coals, and stack reheat. Expected heat rate improvement is in the 1.2 to 5.8% (relative) range, depending on the coal rank. A flue gas cooler is enabling technology, commercially available from several vendors, for recovering heat from the flue gas.

Improvements to Steam Turbine Cycle
The improvements to the steam turbine cycle involve application of high-efficiency turbine blade design, application of better seals, improvement or replacement of feedwater heaters, and improved exhaust hood design. These improvements not only improve efficiency, but also increase unit capacity. This capacity increase represents fuel-free or “green” megawatts, because no additional fuel is used. Improvements in turbine cycle performance range from 2 to 4.5% (relative).

Improvements to Heat Rejection System
Although, improvements to the heat rejection system can result in performance improvements similar in magnitude to the turbine cycle improvements, these can be, in most cases, achieved by proactive and timely maintenance practices. A 2” Hg Abs. change in condenser pressure at full load results in 2% (relative) change in turbine cycle heat rate. At lower loads, the effect of condenser pressure is significantly higher. Cooling tower performance can be improved by use of new, more efficient fill designs. VFDs should be considered for circulating water pumps and fans on mechanical draft towers to reduce auxiliary power use. Converting mechanical draft towers to natural draft will improve heat rate by 0.6% (relative).

Improved Performance of Boiler Auxiliaries
APH performance is very important for maintaining high plant performance and availability. APH leakage, corrosion, and plugging, caused by deposition of sulfuric acid and ABS, increases auxiliary power use and heat rate. An increase in APH pressure drop by 5” H2O can increase unit heat rate by up to 0.45% (relative). Heavy fouling can result in load derate, and compromise unit availability if APH water-washing is needed.

New, high-efficiency seals can reduce APH leakage by a factor of two (a 10%-point reduction in APH leakage improves net unit heat rate by 0.25%). Maintaining proper APH operating conditions can improve heat rate by up to 0.4% (relative). Advanced air preheating can reduce APH corrosion and fouling while simultaneously improving unit performance by up to 1% (relative).

Auxiliary power use can be decreased by installing VFDs on main fans and other large electrical motors. Resulting heat rate improvements are in the 0.3 to 0.9% (relative) range, depending on the unit load profile.
Improvements to Combustion Sensors and Control
Improvements to combustion sensors and control, including tuning and control system upgrades can result in 1 to 3% (relative) improvements in unit heat rate, especially on older unit and units retrofitted with low-NO\textsubscript{x} firing systems. On-line heat rate monitoring can improve performance by 1% (relative).

Balancing of Coal Flow Among Individual Burners
Balancing of coal flow between coal pipes improves unit heat rate and reduces emissions by allowing operation at lower excess O\textsubscript{2} and higher combustion efficiency, and also results in more stable boiler operation. Heat rate improvements, achieved by implementation of this technology, are in the 1% (relative) range.

Combustion Optimization
Combustion optimization represents a cost-effective approach for reducing emissions and optimizing performance of existing combustion and pollution control equipment. Achieved NO\textsubscript{x} reductions are in the 25 to 30% range. Unit heat rate can be improved by 1 to 2% (relative), with higher improvements corresponding to load-following, cycling, and untuned boilers. Mercury emissions can be reduced by as much as two-thirds for power plants firing bituminous coals. For power plants firing Western sub-bituminous coals, mercury emissions can be reduced by one-third.

Sootblowing Optimization
Sootblowing optimization can solve many problems related to slagging and fouling, poor steam temperature control, opacity exceedances, and related capacity and performance losses. The achieved heat rate improvements are typically in the 0.25 to 1% (relative) range. For power plants suffering from opacity exceedances, closed-loop intelligent sootblower control can improve plant power output by 3%, while simultaneously reducing reheat sprays and maintaining more stable steam temperatures.

Repowering
With Rankine-Brayton repowering, a combustion turbine is incorporated into an existing coal-fired power plant to improve its performance and increase capacity. The main benefits include higher efficiency and capacity and lower CO\textsubscript{2} emissions. Lower CO\textsubscript{2} emissions are achieved due to higher efficiency and firing of less carbon-intensive fuel (natural gas).

The solid fuel-based repowering options include application of the fluidized bed technology (bubbling or circulating bed), either at atmospheric or elevated pressure, fluidized bed gasification, and IGCC. These repowering options can improve plant net unit heat rate by up to 30%, while allowing use of low-cost opportunity fuels. In addition, oxygen-blown IGCC is very suitable for implementation of CCS technology. The choice of repowering technology will depend on the required reduction in CO\textsubscript{2} emissions from existing units, cost of CCS, and price of CO\textsubscript{2} emission credits or carbon tax.
Improvements in net unit heat rate and reductions in CO₂ emissions associated with investigated options are analyzed in Appendices I to IX. Heat rate improvements are also summarized in Table 1 in the Executive Summary. The total potential improvement (excluding repowering), although not cumulative and being dependent on many site-specific factors ranges from 3.5 to 12% for bituminous coals, 6.4 to 12.5% for washed Illinois coals, 7.3 to 13.8% for PRB coals, and 9 to 16% for lignites.

In conclusion, there are numerous options available for improving performance and reducing emissions at existing coal-fired power plants. Although potential improvements can be large, the actual improvement depends on many site-specific design, operating, and maintenance conditions and the fuel burned. The actual heat rate improvement has to be determined on a unit-by-unit basis. Higher unit efficiency will allow the existing fleet of coal-fired power plants to continue playing an important and “greener” role in power generation.

**Part 2: CO₂ Capture and Reduction of CO₂ Emissions**
The second part of the study focused on the following options for reducing CO₂ emissions:

- Biomass co-utilization
- Post-combustion CO₂ capture
- Oxy-fuel combustion

Negative effects of biomass co-firing can be eliminated by thermal drying of wet biomass using heat recovered from the flue gas. In addition to improvements in CO₂ separation (capture), the area requiring equal attention is CO₂ liquefaction & compression, where improvements are needed to reduce compression work (currently responsible for about 3 to 4%-point reduction in power plant efficiency). Heat and system integration are needed to reduce CO₂ compression and capture costs. The ERC is working actively in the area of heat integration.

The key challenges for retrofitting post-combustion CO₂ capture to existing power plants include the following: (1) availability of steam for solvent regeneration, (2) major equipment modifications or redundancy, (3) high-efficiency desulphurization equipment required to reduce SOₓ to the 10-30 mg/Nm³ level required by ammine scrubbers, (4) space limitations (many acres are needed for current scrubbing technologies), (5) replacement power needed to offset power loss due to CO₂ scrubbing and maintain base load output, (6) scheduling outages for CO₂ retrofits, (7) post-retrofit dispatch implications due to increased COE (dispatch of scrubbed vs. non-scrubbed units), (8) retrofit triggering NSPS review, and (9) uncertainties concerning proposed legislation.

**Part 3: Improvements for Two Illinois Coal-Fired Power Plants**
The third part of the study focused on implementation of performance-improvement options. To demonstrate effects of performance improving measures, two power stations, comprised of three units firing Illinois coals were visited to identify hardware improvements, collect and analyze plant operating data, and determine effect of
scheduled outages and hardware upgrades on emissions and performance, and identify opportunities (operational and hardware changes) for additional improvements. Results and recommendations are provided for each unit.

**Recommendations for Future Work**

1. Because many power plants fire washed Illinois coals or mine waste containing significant amount of surface moisture, it is recommended that additional studies be performed at selected site(s) to determine site-specific benefits of firing reduced moisture coals and the cost of coal drying. The expected benefits will include higher efficiency and lower emissions, better coal handling, better grindability and lower LOI, lower flow rates of combustion air and flue gas, with a positive effect on the performance of the plant pollution control system.

   It is recommended the coal drying project be conducted in stages. The first stage will involve thermal drying of a portion of the coal feed (25 or 33%) using heat recovered from the flue gas. A coal drying system will be designed in a modular fashion to allow incremental increase in drying capacity. Following evaluation of the performance and emissions benefits, and operational impacts achieved by firing drier coal, a full-scale coal drying system will be implemented in the second phase of the project by adding additional modules.

2. Due to moderate to high sulfur content of Illinois coals, acid dewpoint temperature is high, resulting in high rates of acid condensation, and heavy corrosion, fouling and plugging of APH heat transfer surfaces. Operation of SNCR or SCR reactors for NOx control further aggravates the fouling and corrosion problem due to formation of ammonium bisulfate (ABS).

   To reduce APH fouling and corrosion rates, it is common to preheat air at the APH inlet in a Steam Air Heater (SAH) using steam extracted from the steam turbine, to increase cold end temperature, to maintain “acceptable” rates of acid deposition, and to shift the ABS deposition zone closer to the APH cold end for better cleaning by the existing sootblowing equipment. Unfortunately, as temperature of the inlet air is raised by increasing extraction from the steam turbine, the heat rate penalty increases due to higher temperature of the flue gas leaving the APH and higher extraction flow.

   Implementation of advanced air preheating is recommended to maintain high cold end temperature, reduce acid deposition, and push the ABS deposition zone closer to the cold end without incurring any heat rate penalties. In case of advanced air preheating because the air into the APH is preheated by using heat recovered from the flue gas in a FGC, the net unit heat rate is improved as the inlet air temperature is increased. This is because heat from the flue gas stream is recovered and used for air preheating.
REFERENCES

DISCLAIMER STATEMENT

This report was prepared by Nenad Sarunac and Lehigh University with support, in part, by grants made possible by the Illinois Department of Commerce and Economic Opportunity through the Office of Coal Development and the Illinois Clean Coal Institute. Neither Nenad Sarunac and Lehigh University, nor any of its subcontractors, nor the Illinois Department of Commerce and Economic Opportunity, Office of Coal Development, the Illinois Clean Coal Institute, nor any person acting on behalf of either:

(A) Makes any warranty of representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately-owned rights; or

(B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring; nor do the views and opinions of authors expressed herein necessarily state or reflect those of the Illinois Department of Commerce and Economic Opportunity, Office of Coal Development, or the Illinois Clean Coal Institute.

Notice to Journalists and Publishers: If you borrow information from any part of this report, you must include a statement about the state of Illinois’ support of the project.