OPPORTUNITIES FOR HEAT RATE REDUCTIONS IN EXISTING COAL-FIRED POWER PLANTS: A STRATEGY TO REDUCE CARBON CAPTURE COSTS

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ABSTRACT

The heat rate, or alternately the efficiency, of a coal-fired generating unit will have a strong effect on the cost of carbon capture. When used in combination with oxyfuel combustion or post-combustion capture of CO_2, reductions in unit heat rate will reduce the amount of CO_2 reduction required of the carbon capture system. For this reason, there is considerable interest in developing strategies for improving (that is, reducing) unit heat rate. There are numerous opportunities in the boiler, turbine cycle and heat rejection system of existing units for heat rate reduction. The overall level of improvement which can be achieved will vary with unit design, maintenance condition, operating conditions and type of coal. Given the possible benefits of incorporating unit heat rate improvements into an overall strategy to minimize the costs of CO_2 capture and sequestration, what are the heat rate reduction options, and what is the largest practical reduction in net unit heat rate which can be achieved? This paper discusses some of the possibilities.

INTRODUCTION

It is widely recognized that the heat rate, or alternately the efficiency, of a coal-fired generating unit will have a strong effect on the cost of carbon capture. More efficient units burn less fuel and generate less CO_2 per net MWhr of output power, and this will result in lower costs for CO_2 capture and sequestration. When used in combination with oxyfuel combustion or post-combustion capture of CO_2, reductions in unit heat rate will reduce the amount of CO_2 reduction required of the carbon capture system.

The heat rate improvement opportunities for existing units include reductions in heat rate due to process optimization, more aggressive maintenance practice and equipment design modifications. Opportunities exist in the boiler, turbine cycle and in the heat rejection system. The overall level of heat rate improvement which can be achieved will vary with unit design, maintenance condition, operating conditions and type of coal.

UNIT HEAT RATE, EFFICIENCY, AND CO_2 EMISSIONS

Figure 1 shows a simple sketch of an electricity generating unit, with chemical energy carried into the unit with the fuel $\left(\dot{M}_{coal} \times HHV\right)$, thermal energy rejected to the environment and a net amount of electrical power output $\left(P_{net}\right)$. The unit efficiency is defined as

$$\eta_{unit} = \frac{P_{net}}{\dot{M}_{coal} \times HHV} \tag{1}$$

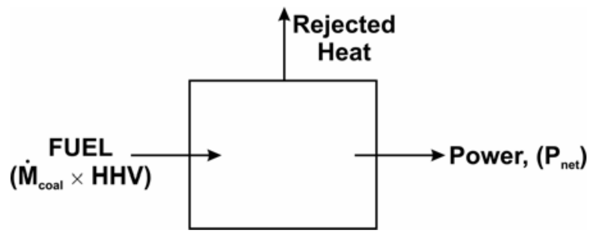

Figure 1: Energy flow rates entering and leaving a power plant.

In the U.S., the net unit heat rate, which is defined as the reciprocal of the efficiency, is expressed in units of Btu/kWhr.

$$HR_{net} \equiv \frac{\dot{M}_{coal} \times HHV}{P_{net}} \tag{2}$$

Thus, if the efficiency is 35%, the net unit heat rate is

$$HR_{net} = (1/0.35) \times 3413 \text{ Btu/kWhr} = 9751 \text{ Btu/kWhr}$$

and a 10% reduction in heat rate to 8776 Btu/kWhr would correspond to an increase in unit efficiency to 38.9 %. It can be seen from Equation 2 that a 10% reduction in unit heat rate results in a 10% reduction in fuel consumption, which, in turn, results in a 10% reduction in CO_2 emissions.

Figure 2 shows a more detailed view of a coal-fired steam power plant, with thermal energy (Q) and power (P) flowing into and out of the boiler and turbine. The net unit heat rate can be written as

$$HR_{net} = \frac{HR_{cycle}}{\eta_{BOILER}} \left[\frac{P_g}{P_g - P_{ss}} \right] \tag{3}$$

where HR_{cycle} is the turbine cycle heat rate, η_{BOILER} is the boiler efficiency, P_g is the gross electrical generation, P_{ss} is the station service power, $Q_{CONDENSER}$ is heat rejected by the condenser, and Q_{STACK} is the energy carried up the stack with the flue gas.

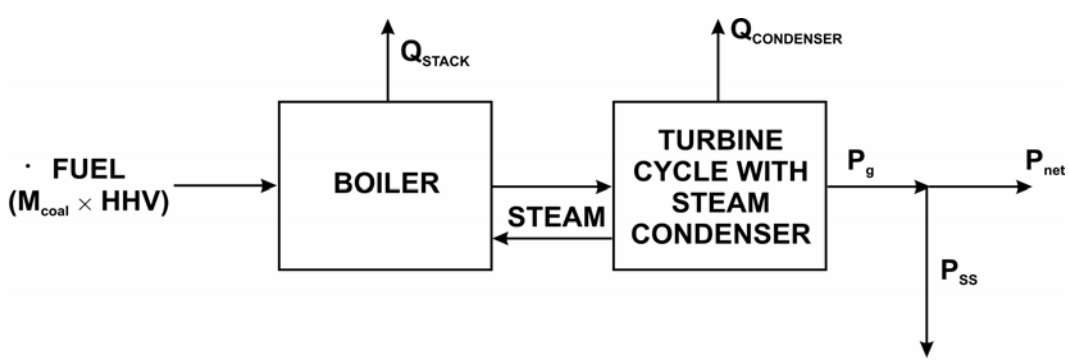

Figure 2: Block diagram of steam power plant.

Improvements in the boiler, steam turbine cycle and heat rejection system can all have beneficial impacts on unit heat rate. These improvements might involve adoption of a more aggressive-than-normal equipment maintenance program, modifications to power plant operating practices, and upgrading and/or adding equipment components. The next section of the paper gives examples of potential heat rate improvements.

EXAMPLES OF POTENTIAL HEAT RATE IMPROVEMENTS

Combustion Optimization. The operating conditions in a typical pulverized coal boiler can be controlled by adjusting the fuel/air ratio and mixing patterns of coal and combustion air. Adjusting these parameters affects quantities such as combustion efficiency, steam temperatures, slagging and fouling patterns and furnace heat absorption, which in many boilers have significant effects on unit heat rate, NO_x emissions, mercury emissions, and stack opacity. Figures 3 and 4 show heat rate results from two coal fired units, (Units A and B) plotted as heat rate versus NO_x emissions. Each data point in the two graphs represents the heat rate and NO_x for one combination of the controllable boiler operating settings. The data for Unit A in Figure 3 show that within the range of NO_x levels from 0.45 to 0.55 lb/MBtu, there was a 1% variation in unit heat rate as the boiler control settings were adjusted. The Unit B baseline control settings in Figure 4 resulted in a NO_x level of 810 ppm and a unit heat rate of 10,285 Btu/kWhr. The results show that operating with optimized boiler control settings at a NO_x level of 750 ppm would have resulted in a unit heat rate of 10,215 Btu/kWhr, which is 0.7% lower than the baseline heat rate.

In some power plants, the boiler operators have discretion over which boiler control settings are used. Table 1 shows differences in heat rate values obtained using the boiler control settings favoured by the various operators at one power plant. These data show there were variations in heat rate of up to 0.65% due to operator variability.

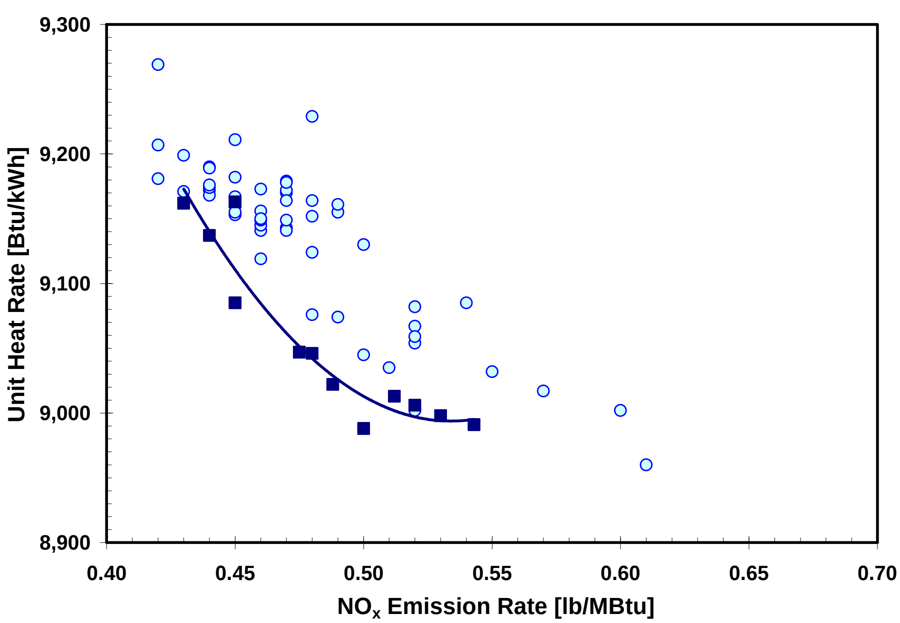

Figure 3: Variations in heat rate and NO_x emissions as boiler control settings are changed at Unit A. Each circular data point represents one combination of boiler control settings. Each dark square is a solution for minimum heat rate derived from the measured heat rate data.

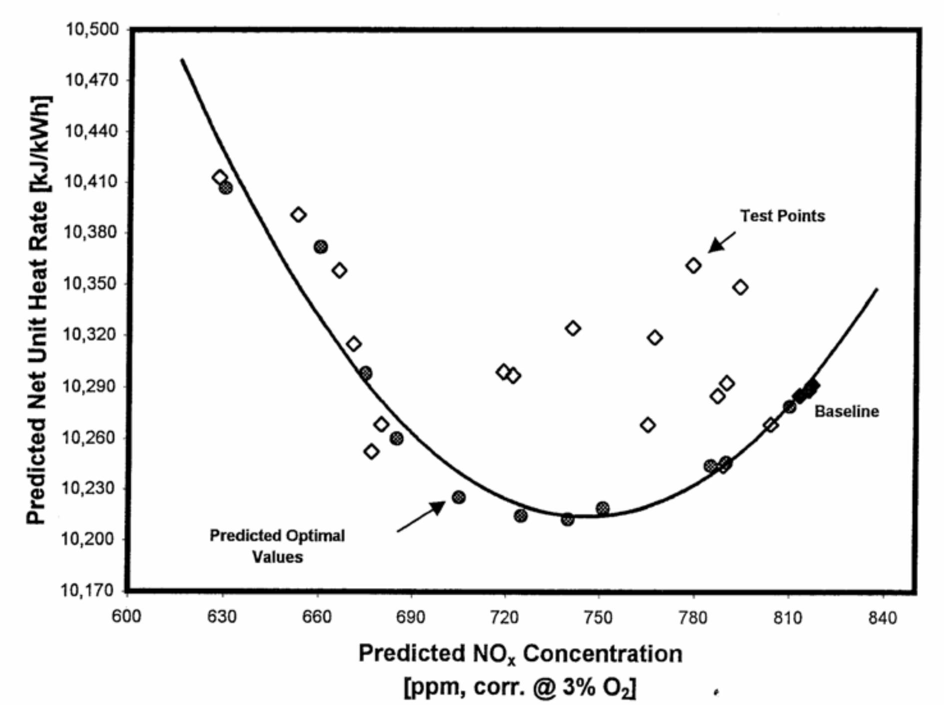

Figure 4: Variations in heat rate and NO_x emissions as boiler control settings are changed at Unit B. Each data point represents one combination of boiler control settings.

Table 1: Effect of Operator Variability on Heat Rate At a Coal-Fired Unit

Boiler Operator	HR_{UNIT} (Btu/kWhr)
1A	10,144
1B	10,144
4A	10,148
5A	10,156
3B	10,180
3A	10,210

Systematic procedures can be used to identify the combinations of boiler control settings which minimize unit heat rate. Referred to as “Combustion Optimization” these procedures typically involve use of intelligent software to perform the optimization. The Energy Research Center has optimized combustion at over 25 coal-fired units at which achievable heat rate reductions in the 0.5 to 1.5 % range were identified [Refs. 1, 2].

<u>Sootblowing Optimization</u>. Slagging and fouling deposits from coal ash accumulation on heat exchanger tubes affect boiler heat absorption patterns, steam temperatures and unit heat rate. Most boilers are equipped with an array of sootblowers which are used to clean boiler tubes by discharging high velocity jets of steam or air onto the slag and ash deposits (Figure 5). Figure 6 shows data from a boiler in which the amount of sootblowing to remove slag deposits on the waterwalls was varied. This caused the waterwall cleanliness factor to extend from a low value of 80% to more than 95% and the hot reheat steam temperature to go from more than 30°F over the design value to close to 40°F below the design value. A waterwall cleanliness factor of 88% resulted in the lowest value of unit heat rate for this boiler. The heat rate increased by 50 Btu/kWhr (approximately a 0.5% increase) at 80% cleanliness and by more than 100 Btu/kWhr (more than a 1% increase) at 98% cleanliness.

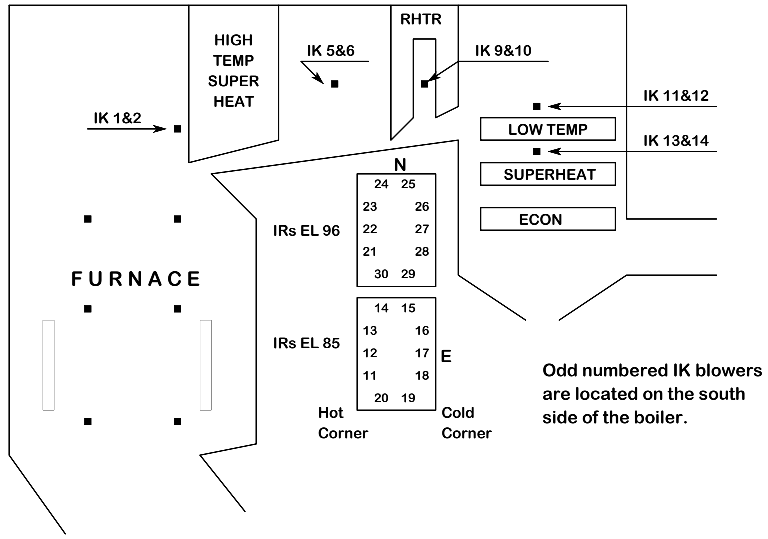

Figure 5: Sootblower locations in a coal-fired boiler.

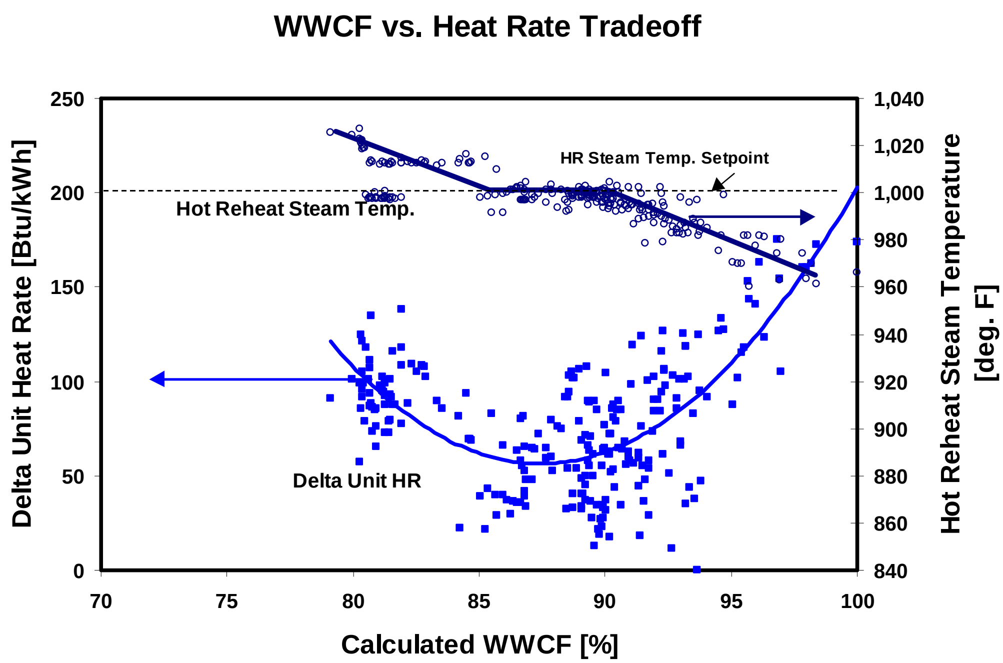

Figure 6: Effect of boiler waterwall cleanliness on unit heat rate.

The challenge is to know which sootblowers to activate and on what schedule in order to prevent large buildup of deposits and maintain the WWCF in the optimal range. Identifying a sootblowing strategy which prevents uncontrolled buildup of slag deposits and minimizes heat rate can be done through a process referred to as sootblowing optimization, and there are adaptive sootblowing optimization software packages available which can be used to automate the process. [Refs. 3, 4].

<u>Steam Temperature Control Impacts On Heat Rate</u>. One of the techniques used to prevent excessively high steam temperatures at the inlets to the high pressure and intermediate pressure turbines is to spray liquid H_2O into the steam. Referred to as attemperating spray, these liquid flows are taken from the turbine cycle and result in an increase in heat rate. Consequently, attemperating spray flow rates should be the minimum flow rates needed to control steam temperatures to the design levels. Table 2 shows data from a unit in which the main steam and hot reheat steam were at lower than desired temperatures, while both main steam and hot reheat attemperating sprays were in operation. This resulted in heat rate penalties due to low steam temperatures and to use of attemperation when it was not needed. The total heat rate penalty was 89 Btu/kWhr or approximately 0.8%. An upgrade to the steam temperature controls and perhaps repair of leaking flow control valves would be needed to prevent this type of loss.

Table 2: Example of Steam Temperature Control Impacts on Unit Heat Rate

	Design	**Actual**	**ΔHR (Btu/kWh)**
T_{MS} °F	1005	996	8
T_{RHT} °F	1000	985	20
$\dot{m}_{MS,spray}(\text{lb/h})$	0	20,000	5
$\dot{m}_{RHT,spray}(\text{lb/h})$	0	22,500	56
		TOTAL	**89**

Effect of Heat Rejection System Performance on Heat Rate. Low pressure steam turbines are designed to operate with specific values of condenser pressure. Referred to as the turbine back pressure or exhaust pressure, this quantity, which is below atmospheric pressure, is typically in the range of 1 to 2 inches of mercury absolute. The turbine back pressure increases above the design value as the steam temperature in the condenser increases above the design value, which results in a reduction in MW produced and an increase in heat rate. For units which reject heat to river water, increases in condenser pressure can occur due to factors such as an increase in river water temperature and/or condenser fouling. For units equipped with cooling towers, factors such as condenser fouling, maintenance related cooling tower performance deterioration, and increases in ambient temperature and humidity can all cause increases in back pressure. Figure 7 shows change in turbine cycle heat rate versus exhaust pressure for different steam flow rates for a 500 MW unit. The full load case (3,450,000 lbm/hr) shows a heat rate increase of more than 2% for an increase in exhaust pressure from 1.5 to 3.5 in Hg. It is not unheard of to find units operating with turbine back pressures approaching 5 in Hg, which results in even larger heat rate penalties.

Using Power Plant Waste Heat to Dry High Moisture Coals. U.S. low rank coals contain relatively large amounts of moisture, with the moisture content of sub-bituminous coals typically ranging from 15 to 30 percent and that for lignites from 25 to 40 percent. High fuel moisture has several adverse impacts on the operation of a pulverized coal generating unit, for it can result in fuel handling problems and it affects heat rate, stack emissions and maintenance costs. The authors recently completed a research project funded by the National Energy Technology Laboratory (NETL) which shows that use of power plant waste heat to reduce coal moisture before pulverizing the coal can provide heat rate and emissions benefits, reduce maintenance costs, and, for units with evaporative cooling towers, it will reduce cooling tower make-up water requirements. The project involved laboratory coal drying studies to gather data and develop predictive models of coal drying rates. The laboratory studies were then followed by computer modeling to determine the relative costs and performance impacts of coal drying and develop optimized drying system designs. The drying system designs which were evaluated [Refs. 6, 7] utilized various combinations of thermal energy from the boiler and heat rejected by the steam condenser for drying coal in a fluidized bed (Figure 8).

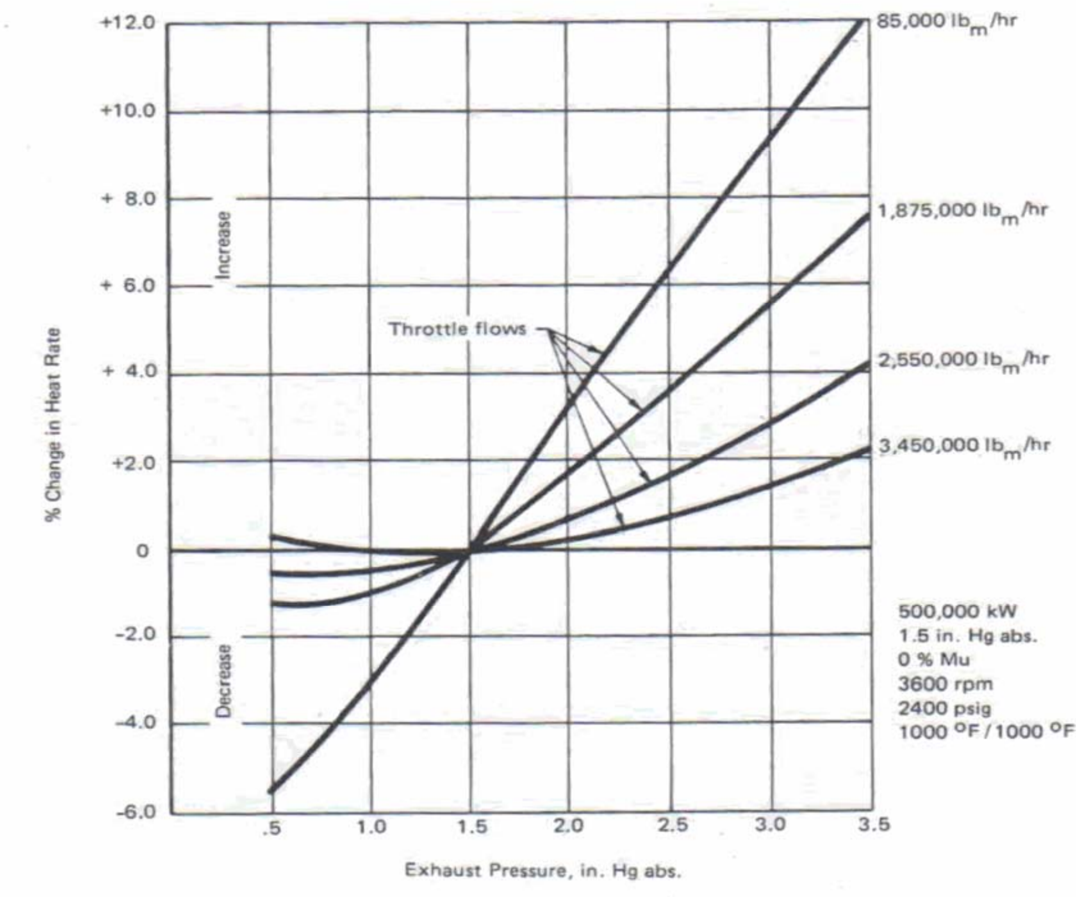

Figure 7: Effect of turbine back pressure on heat rate. [Ref. 5]

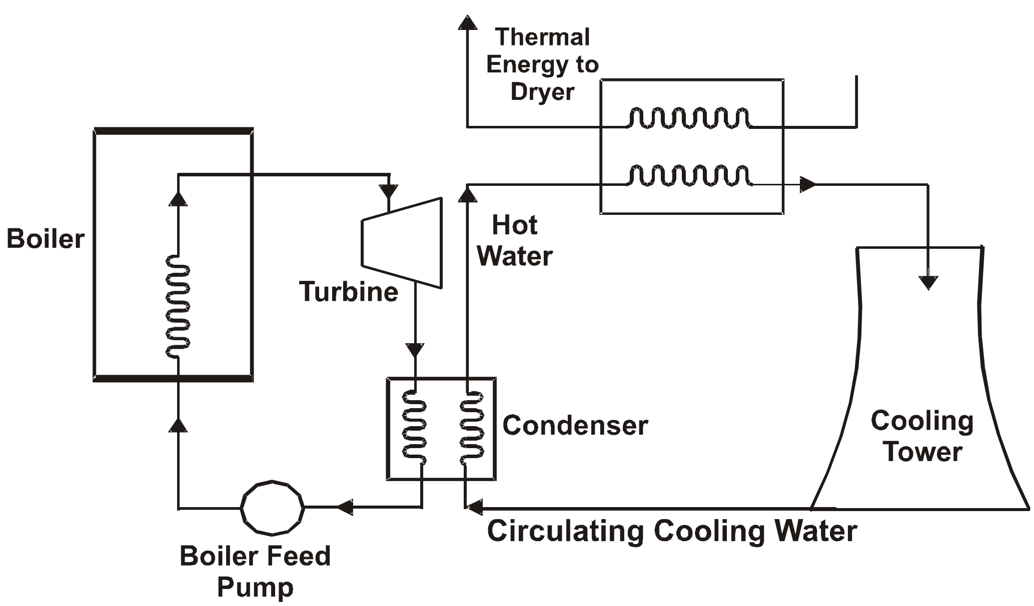

Figure 8: This drying system uses a combination of thermal energy from the condenser cooling water and boiler as the heat source.

The results in Figure 9 show that the degree to which performance improves depends strongly on the degree of drying. Calculations for a 550 MW lignite-fired unit show that for a 20 percent reduction in coal moisture, there will be a 3 percent increase in boiler efficiency, a 3.3 percent decrease in net unit heat rate, a 3.3 percent reduction in emissions such as CO_2 and SO_2 and a 2×10^5 gallon per day reduction in cooling tower makeup water (See Table 3). Reductions in NO_x and Hg emissions are also expected, but the magnitudes of these will depend on site-specific factors.

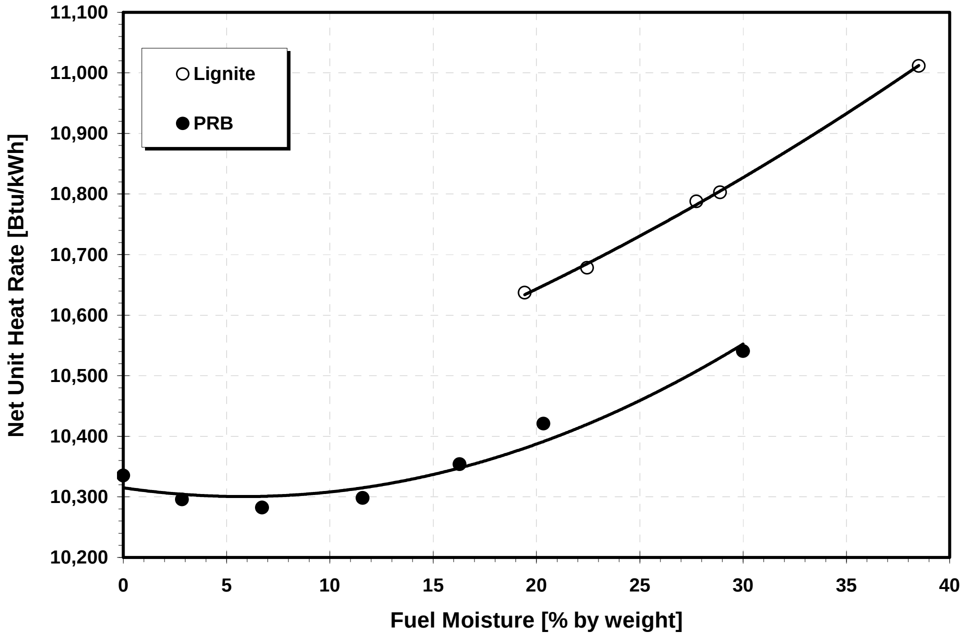

Figure 9: Effect of coal moisture and coal type on net unit heat rate.

Table 3. Effects of lignite drying on changes in key plant performance parameters with a 20 percent reduction in coal moisture.

Boiler Efficiency	+3%
Net Unit Heat Rate	-3.3%
SO_2 and CO_2	-3.3%
Station Service Power	Negligible
Cooling Tower Makeup Water	- $2x10^5$ gallons/day

With funding from DOE, Great River Energy is in the process of installing fluidized bed dryers at a lignite-fired unit at Coal Creek Station near Bismarck, North Dakota. The drying system at Coal Creek will use power plant waste heat to predry the coal, with heat rate gains expected to be in the 2.5 to 3% range. [Ref. 8]

Recovering Moisture From Boiler Flue Gas Using Condensing Heat Exchangers. Use of heat exchangers between the boiler and stack to recover water vapor from flue gas also provides opportunities to improve unit heat rate (Figure 10). Under the right conditions, sensible and latent heat transferred from the flue gas can be used to preheat boiler feedwater, thus reducing both the steam turbine extraction flows to the feedwater heaters and unit heat rate (Figure 11). The potential magnitude of the heat rate impact was determined from analyses carried out for both subcritical and supercritical cycles, where the inlet feedwater temperature to the flue gas feedwater heater was 87.1°F for the supercritical cycle and 105.3°F for the subcritical cycle. The flue gas entering the condensing heat exchangers was assumed to be at 300°F, which is a typical ESP gas exit temperature.

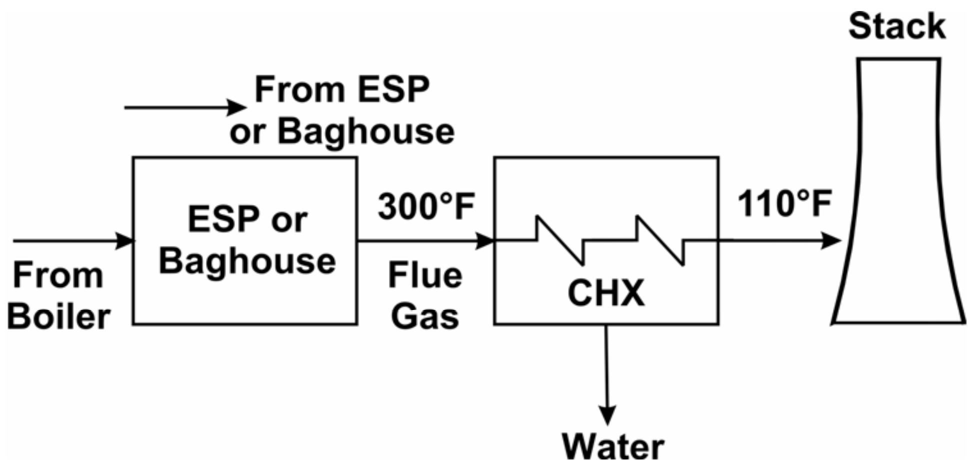

Figure 10: Use of a condensing heat exchanger to recover water from boiler flue gas.

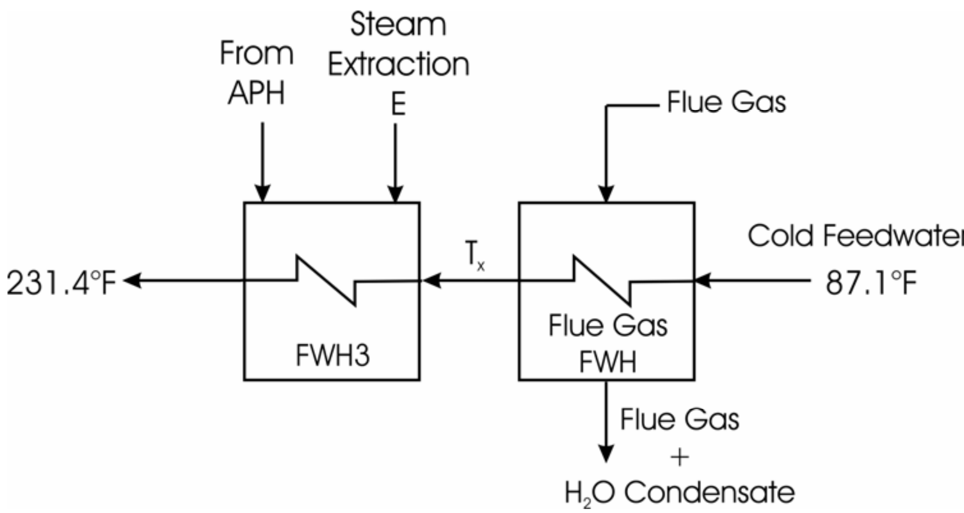

Figure 11: Use of a condensing heat exchanger to preheat low temperature boiler feedwater, which results in reductions in unit heat rate.

The analyses were performed for four U.S. coals, ranging from a relatively low-moisture bituminous coal to a high-moisture lignite. For both cycles, the improvements in turbine cycle heat rate and unit heat rate were estimated to be in the 1 to 2% range. [Ref. 9] The heat rates increased with increasing inlet flue gas moisture concentration and with decreasing inlet feedwater temperature (Figure 12).

SUMMARY OF HEAT RATE IMPROVEMENT OPPORTUNITIES

Table 4 summarizes the opportunities to improve heat rate for units fired with low moisture bituminous coals, along with typical percentage heat rate reductions. If improvements could be made in all of these areas, the net improvement in heat rate would range from 6.5 to 11.5%. While it is not be possible to take advantage of all of these improvements on every unit which uses low moisture coals, Table 4 shows there is potential for making significant heat rate improvements to this group of generating units.

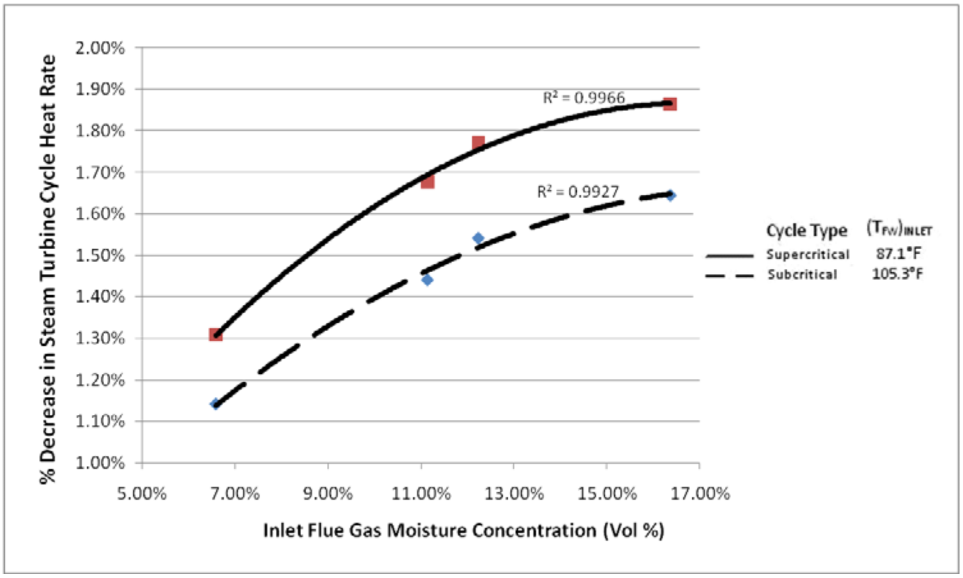

Figure 12: Effects of inlet flue gas moisture concentration and inlet feedwater temperature on heat rate improvement.

Table 4: Examples of Heat Rate Improvement Opportunities: Low Moisture Bituminous Coals

	Potential Heat Rate Reduction
BOILER	
• Optimize Combustion and Sootblowing	(1.0 to 2.0%)
• Upgrade Steam Temperature Control Capabilities	(1.0%)
• Recover Moisture from Flue Gas	(1.0 to 2.0%)
• Upgrade Air Preheater Seals	(0.5%)
TURBINE CYCLE AND COOLING SYSTEM	
• Install Advanced Steam Turbine Blading and Seals	(2 to 3%)
HEAT REJECTION SYSTEM	
• Upgrade Cooling System Performance	(1 to 3%)
Total	**6.5 to 11.5 %**

Table 5 itemizes the opportunities to improve heat rate for units fired with high-moisture, low rank coals or high moisture bituminous coals. This list includes the same items shown in Table 4, along with the addition of potential heat rate reductions obtained by pre-drying high moisture coals using power plant waste heat and by reducing flue gas temperature to 100°F. Maximum improvements in heat rate would range from 8.5 to 15.5% for these units.

Table 5: Examples of Heat Rate Improvement Opportunities:
Low Rank Coals and High Moisture Bituminous Coals

	Potential Heat Rate Reduction
BOILER	
• Optimize Combustion and Sootblowing	(1.0 to 2.0%)
• Upgrade Steam Temperature Control Capabilities	(1.0%)
• Upgrade Air Preheater Seals	(0.5%)
• Pre-dry High Moisture Coals Using Power Plant Waste Heat	(2 to 4%)
• Recover Moisture from Flue Gas	(1.0 to 2.0%)
• **TURBINE CYCLE AND COOLING SYSTEM**	
• Install Advanced Steam Turbine Blading and Seals	(2 to 3%)
HEAT REJECTION SYSTEM	
• Upgrade Cooling System Performance	(1 to 3%)
Total	**(8.5 to 15.5%)**

SUMMARY AND CONCLUSIONS

There is a direct relationship between the efficiency or heat rate of a coal-fired generating unit and the cost of carbon capture. More efficient units burn less fuel and generate less CO_2 per net MWhr of output power, and this will result in lower costs for CO_2 capture and sequestration. When used in combination with oxyfuel combustion or post-combustion capture of CO_2, reductions in unit heat rate will reduce the amount of CO_2 reduction required of the carbon capture system and the amount of CO_2 which must be sequestered.

The heat rate improvement opportunities for existing pulverized coal units include reductions in heat rate due to process optimization, more aggressive maintenance practice and equipment design modifications. Opportunities exist in the boiler, turbine cycle and heat rejection system. The overall level of heat rate improvement which can be achieved will be extremely site specific, varying with unit design, maintenance condition and operating conditions. Magnitudes of potential heat rate improvement also depend on coal type, ranging from 6.5 to 11.5% for low moisture bituminous coals from 8.5 to 15.5% for low rank coals or high-moisture bituminous coals. These correspond to potential reductions in CO_2 emissions of up to 15.5% for units firing high moisture coals and 11.5% for units operating with low moisture coals.

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