Heat Rate Improvements and Limitations Based on EPA's Block Strategies

Speaker:	**Emily Kunkel** **Sargent & Lundy**
Session Title:	**2A - Clean Coal Plan**
Conference Track:	**Emissions Control I**
Presentation Date & Time:	**Tuesday, December 8, 2015** **1:30PM- 3:30PM**

Authors: Emily J. Kunkel,[1] Rajendra Gaikwad,[1] William A. Rosenquist,[1] Michael J. Casper,[2] Rae E. Cronmiller[2]

[1] Sargent & Lundy LLC, Chicago, IL.
[2] National Rural Electric Cooperative Association, Arlington, VA.

1.0 Introduction

On August 3, 2015, United States Environmental Protection Agency (EPA) finalized the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule" and published in the *Federal Register* (80 Fed. Reg. page 64661) on October 23, 2015. EPA analyzed potential CO_2 emission reductions associated with various "building blocks" that affect the power generating industry as part of the Best System of Emission Reduction (BSER). The building blocks included: (1) reducing CO_2 emissions (i.e., lb CO_2/MW-net) at individual affected coal-fired electric generating units (EGUs) through heat rate improvements; (2) CO_2 emission reductions achievable through re-dispatch from coal-fired units to existing natural gas combined cycle (NGCC) units; and (3) expanded use of renewable energy resources. EPA quantified the emission reductions achievable through building block 1 (BB1) on a regional basis, identifying the heat rate improvements achievable by coal-fired EGUs as 4.3% for the Eastern Interconnection, 2.1% for the Western Interconnection, and 2.3% for the Texas Interconnection.

Heat rate improvements that may be achieved by adopting EPA's defined "best practices" and "upgrades" were based, in part, on EPA's review and interpretation of a report, titled "Coal-Fired Power Plant Heat Rate Reductions" prepared by Sargent & Lundy in 2009 for the EPA (hereafter referred to as the "2009 Report") and their own statistical analysis that is not evaluated in this study. The purpose of the 2009 Report was to identify various methods that have been successfully implemented in the industry to reduce the heat rate of existing U.S. coal-fired power plants. Improvement ranges were based on publicly available data, data from original equipment manufacturers (OEMs), and S&L experience and were meant to be applied to typical equipment. These values provided were meant to represent a range only if the methods are applicable to the unit.

The 2009 Report also provided two conceptual level case studies: one for a 250 MW unit and the second for an 850 MW unit, to provide examples of how heat rate improvement projects would be implemented and to identify some of the site-specific technical issues that would need to be taken into consideration. Since each unit should be analyzed on a unit-by-unit basis, these case studies are only meant to represent two possible scenarios and guide the reader on the proper methodology for the use of identified technologies.

The National Rural Electric Cooperative Association (NRECA) is a national service organization representing the interests of electric cooperative utilities and the consumers they serve. Collectively the electric cooperative owns more than 100 coal-fired units around the country; these units are comprised of a broad range of types of boilers, capacities, fuels fired, and installed Air Quality Control System (AQCS) equipment. The purpose of this engineering study is to conduct a review for NRECA of potential heat rate improvements that can be applied to existing coal-fired power plants, and to identify potential limitations in applying these technologies.

2.0 Technology Limitations

Based on information provided in the 2009 Report, "EPA estimated that for a range of heat rate improvements from 415 to 1205 Btus per kWh, corresponding to percentage heat rate improvements of 4 to 12 percent for a typical coal-fired EGU, the required capital costs would range from $40 to $150 per kW." (79 FR 34861) However, based on a review of EPA's "GHG Abatement Measures" Technical Support Document, the EPA misapplied information presented in the 2009 Report when it calculated heat rate improvements of 415 to 1205 Btu/kWh and 4 to 12 percent. EPA assumed that heat rate improvements cited in the 2009 Report were additive and applicable to all coal-fired units. Contrary to the approach used by EPA, heat rate improvement opportunities, and the associated costs, must be evaluated on a case-by-case basis taking into consideration unit-specific design, operations, and controls.

When evaluating heat rate reduction strategies, it is important to consider the limitations of each heat rate improvement (HRI) strategy. The following table highlights many of the limitations that the evaluated HRI technologies have, due to fuel, unit size/type, AQCS equipment, and other site-specific limitations. This list does not detail every possible limitation, but rather introduces high level considerations that should be accounted for when developing a heat rate improvement plan. This discussion is meant to be used as a cursory tool for evaluating HRI methods, but a site-specific analysis may reveal additional limitations.

Table 1:* Heat *Rate Improvement Method Limitations

HRI Method	Limitations
Boiler Island	
(1) Coal transport, conveying, and grinding	- Minimal efficiency gain compared to total retrofit work required. - Spatial constraints may limit applicability.
(2) Boiler operation/overhaul with new heat transfer surface	- Increasing heat transfer surface area in the boiler could increase steam generation to beyond the steam turbine design which could require additional changes. - Any increase in steam flow may also require increase in coal flow thus possibly triggering NSR under some circumstances. - Periodic replacement to recover the steam generation capacity of the unit does not yield any increase in efficiency. - Units (limited number) required to add economizer surface area to lower temperatures at full load to prevent sintering of SCR catalyst

HRI Method	Limitations
	must frequently also raise temperatures at lower loads to prevent ammonium salt deactivation of the catalyst. These competing goals limit the HRI at full load.
(3) Neural network (NN) control system	- Units using NN for NOx control have generally achieved HRI through lower excess air and optimized air to fuel ratio and cannot further optimize the boiler operation for heat rate improvement without sacrificing NOx reduction. - Units not already equipped with distributed control system (DCS) controls will have a harder time implementing the intricate system.
(4) Intelligent sootblower (ISB) system	- Many units are forced to continuously use their sootblowers to keep the back end of the boiler from slagging. Operation in intelligent mode will provide little HRI benefit on these units. - The benefits from ISB and NN are not additive.
(5) Air heater leakage mitigation	- Many units already employ best operation and maintenance practices (BP)*, thereby negating further heat rate improvement. - Some types of air heaters' rotating hood structures are more susceptible to warping over time, increasing air heater leakage. Even with seal replacement, units with this problem are unable to achieve design leakage. - Location of air heater typically does not allow replacement with a larger low-leakage air heater with seal-air control.
(6) Air heater acid dew point reduction	- Units with DSI already installed downstream of the air heater, due to avoiding potential plugging, cannot implement this technology. - Most of the high sulfur bituminous coal with SCRs already have installed this technology and those systems are optimized for SO_3 emission rather than HRI - Units burning powder river basin (PRB) coal or lignite will have sufficient alkali in the form of CaO which allows absorption of SO_3 before and in the air heater thus permitting operator to operate at lower dew point. Acid dew point reduction technology is therefore not applicable for units burning PRB and lignite.
Turbine Island	
(7) Turbine overhaul and upgrade	- Units that have been upgraded or commissioned after 1995 generally have modern turbine packing/technology, thus limited benefit would be gained from further improvement. - Due to large size of low pressure (LP) turbine section, and limited impact in comparison with the high pressure (HP) section, improvement is typically outweighed by performance payoff. Therefore, this improvement is not typically performed for heat rate purposes.

HRI Method	Limitations
(8) Feedwater heater	- Heating surface could be added to improve efficiency; however high capital cost is required for a relatively small incremental reduction in heat rate.
(9) Condenser	- Many units already employ BP*, thereby negating further heat rate improvement. - Units with recently improved mechanical cleaning systems will not significantly benefit from condenser cleaning.
(10) Boiler feed pump	- Units with recently improved boiler feed pumps will not benefit from further improvement. - Many units that already employ BP* will not achieve further improvement.
Flue Gas System	
(11) a. Forced draft (FD) and induced draft (ID) fan improvement	- Many units have already replaced their centrifugal fans with axial fans during projects with high pressure drop associated with air pollution control projects; therefore, this HRI has already been incorporated on a large number of units.
(11) b. Variable-frequency drive (VFD)	- Many units, that have improved their ID fans recently, have already incorporated VFDs on their centrifugal. - Not applicable for use on axial fans. - VFDs must be located close to the equipment, so appropriate access is required.
Air Pollution Control Equipment	
(12) Flue gas desulfurization (FGD) system	- Minimal efficiency gain compared to total retrofit work required. - Applicability is limited to WFGDs operating at lower than design sulfur or lower than full load. - Plans reducing heat rate through FGD modifications, such as operating bypasses or scrubbing the flue gas less efficiently, often risk emission increase. - Not applicable to dry or semi-dry FGD, as well as jet bubbling reactor (JBR) or venturi scrubber WFGDs.
(13) Particulate system	- Implementing energy management systems (EMS) is likely not feasible while maintaining filterable particulate matter (FPM) emission limits established by MATS. - Is not applicable for units with baghouses.
(14) Selective catalytic reduction (SCR) system	- Minimal efficiency gain compared to total retrofit work required. - Recently designed/installed SCRs already have completed rigorous computational fluid dynamics (CFD) modeling to optimize pressure drop.

HRI Method	Limitations
	- Applicability is limited to units with existing SCRs.
Water Treatment System	
(15) Boiler water treatment	- Many units already have a modern water treatment system to reduce scaling. - Heat rate improvement is likely not better than BP* associated with condenser cleaning.
(16) Cooling tower:	- Many units among the fleet have already implemented counter-flow configurations. - Improvements to cooling towers may have spatial constraints.

*Note: If a unit employs best operational and maintenance practices currently, the HRI method may not be applicable for further improvement. However, these practices must be continued for the life of the unit to maintain current heat rate levels.

The EPA suggests restricting unit dispatch to avoid triggering new source review (NSR).[1] If best available control technology (BACT) review is required as a consequence of an NSR trigger, the installation of additional and expensive control technologies may be required. Therefore, while certain improvement opportunities may exist and provide potential heat rate reductions for units, they may be determined to be unfeasible due to NSR implications.

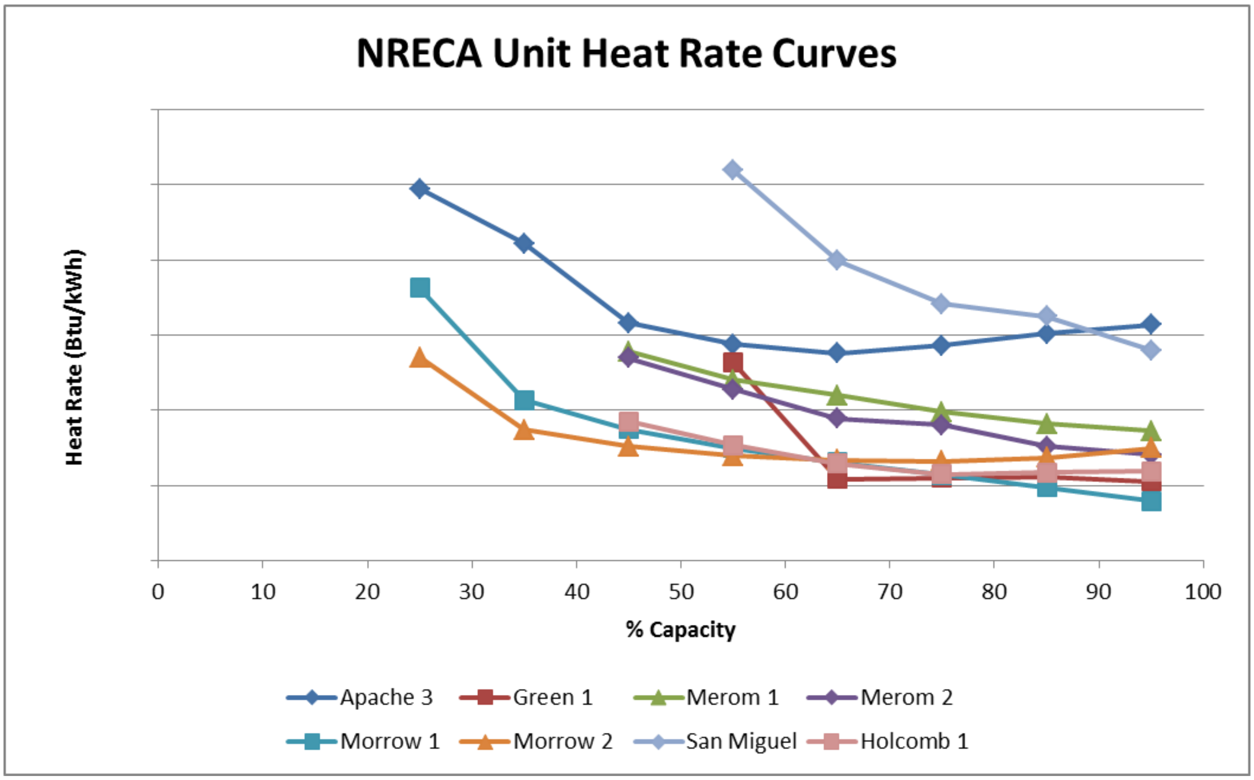
The 2009 Report did not include a discussion as to the impact of applying multiple technologies simultaneously. In some cases, the heat rate reduction estimated to be achieved through a combination of technologies may be equivalent to the sum of each technology's estimated heat rate reduction. However, in many cases, the estimated heat rate reduction of a combined strategy would be less than the sum of each technology's estimated heat rate reduction. Because of the interdependency of variables for many of these heat rate improvement technologies, combinations of technologies cannot be assumed to have an additive impact on heat rate. Combinations of technologies should be assessed on a case-by-case basis to determine the combined heat rate improvement.

[1]See, 79 FR 34928, col.2.

3.0 Effect of Decreased Dispatch

Block 2 of the EPA's CO_2 reduction strategy stated in the draft regulation, requires increasing generation dispatch to NGCC units, due to the lower CO_2 emission rate (in lb/MMBtu) that is associated with natural gas.[2] Additionally, Block 3 of the EPA's strategy suggests dispatching more generation to renewable resources like wind and solar. By increasing dispatch to other sources, many coal-fired units may be forced to operate at lower loads consistently. Since most coal-fired units cannot maintain low heat rates while cycling or maintaining low loads, this has the potential to increase their annual average net unit heat rate (NUHR) from their baseline average. Units that are base loaded, or tend to run higher than 90% capacity, will have a lower heat rate than units that are forced to cycle continuously or those dispatched more consistently at low loads. To understand how varying dispatch loads affect the heat rate of units within the fleet, six plants with a total of nine units in the electric cooperative fleet were analyzed.

Figure 1: Analysis of Heat Rate vs. Unit Dispatch



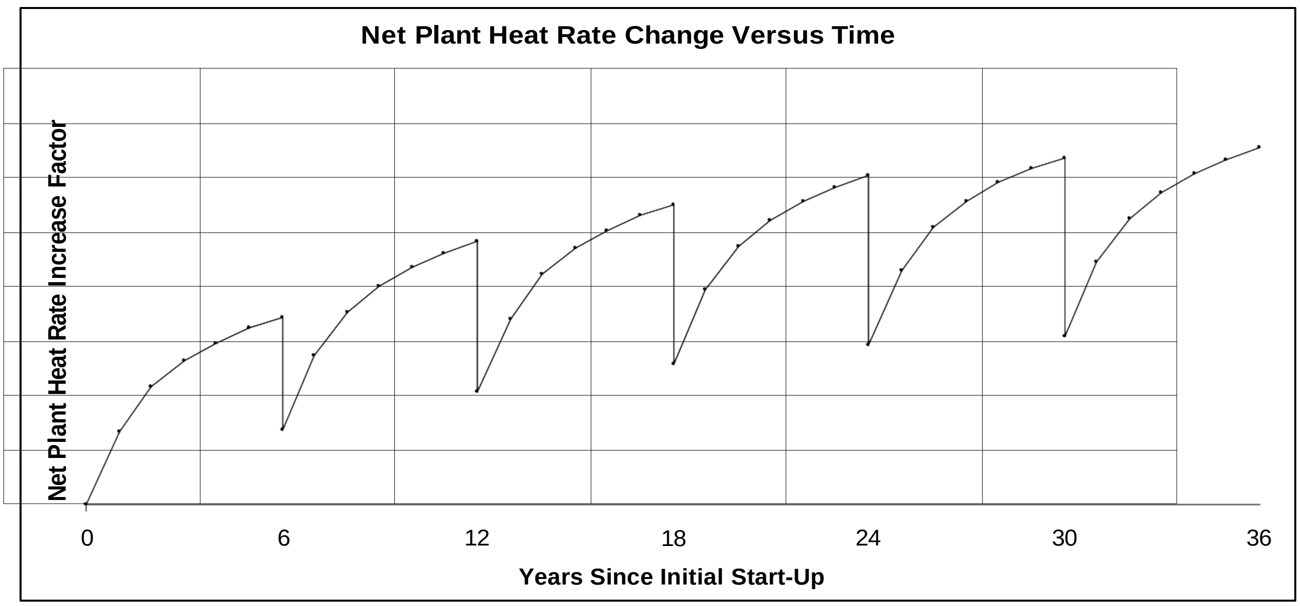
[2]Values for CO_2 emission-rate are listed to be 117 lb/MMBtu for natural gas firing. The CO_2 emission-rate for coal firing depends on the type of coal. For bituminous coal, the CO_2 emission-rate is listed to be 206 lb/MMBtu. For subbituminous coal, the CO_2 emission-rate is listed to be 214 lb/MMBtu. Lignite emission-rate is 212 lb/MMBtu.

Dispatching units at lower loads or in cycling regimes more than they have historically will increase NUHR, thus negating much, if not all, of the potential benefits achieved with heat rate improvement methods at full load.

4.0 Heat Rate Degradation

Pursuant to the proposal, each state would be required to achieve their interim goals by 2022, and their final goal must be achieved after 2030 on a three-year average. Even if it is assumed that it is possible to achieve a measurable heat rate reduction immediately after implementing various HRI strategies outlined in this study, it will be much more difficult to maintain that percentage improvement over a long term timeframe, because each piece of major equipment degrades with continued operation. While OEMs may provide an initial guarantee for equipment improvements, the future performance must be considered when determining the sustainable heat rate reduction over the lifetime of the equipment. Normal performance degradation often occurs in a "sawtooth pattern" which identifies decreased performance between maintenance cycles.

Figure 2: Typical Heat Rate Degradation vs. Time



Some HRI technologies are more susceptible to degradation over time, and some technologies will not significantly degrade over time. With most HRI methods, upon completion of the maintenance activities, the unit will show improvement in heat rate initially and will degrade between maintenance outages, as seen by Figure 2; the average of these two values may be considered to be the sustainable heat rate improvement. Completing these maintenance activities on a consistent basis is required in achieving the average sustainable heat rate improvement. Therefore, performance degradation should be accounted for when considering certain HRI technologies as part of a long-term sustainable heat rate improvement strategy.

5.0 Case-Studies

Two stations within the NRECA member cooperative fleet were analyzed on a unit-by-unit basis to estimate the total heat rate improvement that has already been made to the units in addition to the potential future improvements. Two units at "Station A" were analyzed, Unit A1 and A2, which are located in the Eastern Interconnection.

Table 2: Summary of Heat Rate Changes for Unit A1 (Existing and Potential) *Note 1*

Heat Rate Improvement	% Change Achieved to Date Note 2	Future Potential % Change
Boiler Island		
Material Handling	BP	-0.1% Note 3
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP to cont. Note 4
Neural Network & Intelligent Sootblowers	BP	BP to cont. Note 5
Air Pre-Heater		
Reduce Air Heater Leakage	BP	BP to cont.
Reduce Flue Gas Acid Dew Point	0%	N/A
Turbine Island		
Turbine Overhaul	-1.5%	-0.5%
Feedwater Heaters	BP	BP to cont.
Condenser	BP	BP to cont.
Boiler Feed Pumps	BP	BP to cont.
Flue Gas System		
FD and ID Fan Efficiency	<-0.05%	0%
Primary Air Fans	0%	0%
Air Pollution Control Equipment		
FGD System Note 6	+2.9%	N/A
SCR System	+1%	N/A
ESP	0%	N/A
Water Treatment System		
Boiler Water Treatment	BP	BP to cont.
Cooling Towers	N/A	N/A
Large Scale Motors	0%	BP to cont.
TOTAL IMPROVEMENT	**+2.4%**	**-0.6%**
IMPROVEMENT ON BOILER ISLAND ONLY	**0%**	**-0.1%**

Note 1: All improvements in the table are denoted by a negative number. All heat rate penalties are denoted by positive numbers. Note 2: Includes improvements achieved from 2000 through 2014.
Note 3: The predicted heat rate improvement includes values from a typical conversion from a wet to dry BA handling system. However, it is unknown at this time whether this will be economically feasible.
Note 4: "BP" is defined as "Best Practices" and incorporates optimized operation and consistent maintenance to sustain the unit's heat rate at its original design. BP reduces the significant degradation of the unit's performance.
Note 5: Although NN & ISB is technically applicable to this unit, no improvement is predicted due to BP already employed.
Note 6: Change in heat rate due to FGD auxiliary power was approximated at 17MW; however, this was partially offset by other projects that occurred at the same time, including ESP improvement, turbine rebuild, and installation of a larger axial ID fan.

Table 3: Summary of Heat Rate Changes for Unit A2 (Existing and Potential) Note 1

Heat Rate Improvement	% Change Achieved to Date Note 2	Future Potential % Change
Boiler Island		
Material Handling	BP	-0.1% Note 3
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP to cont. Note 4
Neural Network & Intelligent Sootblowers	BP	BP to cont. Note 5
Air Pre-Heater		
Reduce Air Heater Leakage	-0.5%	BP to cont.
Reduce Flue Gas Acid Dew Point	0%	N/A
Turbine Island		
Turbine Overhaul	0%	-2.0% Note 7
Feedwater Heaters	BP	BP to cont.
Condenser	BP	BP to cont.
Boiler Feed Pumps	BP	BP to cont.
Flue Gas System		
FD and ID Fan Efficiency	0%	<-0.05%
Primary Air Fans	-0.4%	N/A
Air Pollution Control Equipment		
FGD System Note 6	+1.8%	N/A
SCR System	+1%	N/A
ESP	N/A	N/A
Water Treatment System		
Boiler Water Treatment	BP	BP to cont.
Cooling Towers	-0.09%	N/A
Large Scale Motors	0%	BP to cont.
TOTAL IMPROVEMENT	**+1.81%**	**-2.1%**
IMPROVEMENT ON BOILER ISLAND ONLY	**-0.5%**	**-0.1%**

Note 1: All improvements in the table are denoted by a negative number. All heat rate penalties are denoted by positive numbers. Note 2: Includes improvements achieved from 2000 through 2014.
Note 3: The predicted heat rate improvement is based on a typical conversion from wet to dry BA handling. However, it is unknown at this time whether this will be economically feasible.
Note 4: "BP" is defined as "Best Practices" and incorporates optimized operation and consistent maintenance to sustain the unit's heat rate at its original design. BP reduces the significant degradation of the unit's performance.
Note 5: Although NN & ISB is technically applicable to this unit, no improvement is predicted due to BP already employed.
Note 6: Change in heat rate due to FGD auxiliary power was approximated at 11MW; however, this was partially offset by other projects that occurred at the same time, including axial fan conversion, VFD installation on PA fans, and rerouting flue gas path. Note 7: While 5% is estimated by OEMs for both the HP/IP and LP sections, it is predicted that the actual improvement immediately after implementation will be less than that. This is based on the large difference between estimated and actual heat rate improvement achieved with the Unit A1 turbine project.

Based on the site-specific constraints, AQCS equipment, operating and maintenance practices, and other unit-specific constraints, the units are predicted to have 0.6% and 2.1% potential heat rate improvement in the future, respectively. This is significantly below the 4.3% heat rate reduction basis for the Eastern Interconnection. It should be noted that these units were penalized due to installation of wet FGD and SCRs by approximately 2.4% and 1.8% heat rate, respectively, that has occurred between 2000 and the date of this study.

Three units comprising “Station B” in the Western Interconnection were analyzed, Units B1, B2, and B3.

Table 4: Summary of Heat Rate Changes for Unit B1 (Existing and Potential) [Note 1]

Heat Rate Improvement	% Change Achieved to Date [Note 2]	Future Potential % Change
Boiler Island		
Material Handling	0%	-0.1%
Boiler Operation/Overhaul with New Heat Transfer Surface	0%	BP to cont. [Note 3]
Neural Network & Intelligent Sootblowers	0%	BP to cont. [Note 4]
Air Pre-Heater		
Reduce Air Heater Leakage	0%	BP to cont.
Reduce Flue Gas Acid Dew Point	0%	N/A
Turbine Island		
Turbine Overhaul	-3.5%	N/A
Feedwater Heaters	0%	BP to cont.
Condenser	0%	BP to cont.
Boiler Feed Pumps	0%	BP to cont.
Flue Gas System		
FD and ID Fan Efficiency	-2.1% [Note 5]	N/A
Primary Air Fans	0%	N/A
Air Pollution Control Equipment		
FGD System	0%	N/A
SCR System	N/A	+1%
Particulate Collection Device	N/A	N/A
Water Treatment System		
Boiler Water Treatment	N/A	BP to cont.
Cooling Towers	0% [Note 6]	N/A
Large Scale Motors	0%	BP to cont.
TOTAL IMPROVEMENT	**-5.6%**	**+0.9%**
IMPROVEMENT ON BOILER ISLAND ONLY	**0%**	**-0.1%**

Note 1: All improvements in the table are denoted by a negative number. All heat rate penalties are denoted by positive numbers. Note 2: Includes improvements achieved from 2000 through 2014.

Note 3: “BP” is defined as “Best Practices” and incorporates optimized operation and consistent maintenance to sustain the unit’s heat rate at its original design. BP prevents significant degradation of the unit’s performance.

Note 4: Although NN & ISB is technically applicable to this unit, no improvement is predicted due to BP already employed.

Note 5: The fan improvements were made at the same time other improvements occurred on the unit; therefore, while some of the heat rate reduction is likely due to the ID/FD fan conversion to axial configuration, the remainder can be attributed to turbine maintenance and the discontinued use of the ESP.

Note 6: Although high efficiency fill has been added to the system and cooling tower fan blades have been modified, the change in heat rate is unknown. It is assumed that due to the problems with the high efficiency fill, the net heat rate has changed very little.

Table 5: Summary of Heat Rate Changes for Unit B2 (Existing and Potential) [Note 1]

Heat Rate Improvement	% Change Achieved to Date [Note 2]	Future Potential % Change
Boiler Island		
Material Handling	0%	-0.1%
Boiler Operation/Overhaul with New Heat Transfer Surface	0%	BP to cont. [Note 3]
Neural Network & Intelligent Sootblowers	0%	BP to cont. [Note 4]
Air Pre-Heater		
Reduce Air Heater Leakage	0%	BP to cont.
Reduce Flue Gas Acid Dew Point	0%	N/A
Turbine Island		
Turbine Overhaul	-3.5%	N/A
Feedwater Heaters	0%	BP to cont.
Condenser	0%	BP to cont.
Boiler Feed Pumps	0%	BP to cont.
Flue Gas System		
FD and ID Fan Efficiency	-1.8% [Note 5]	N/A
Primary Air Fans	0%	N/A
Air Pollution Control Equipment		
FGD System	0%	N/A
SCR System	N/A	+1%
Particulate Collection Device	N/A	N/A
Water Treatment System		
Boiler Water Treatment	N/A	BP to cont.
Cooling Towers	0% [Note 6]	N/A
Large Scale Motors	0%	BP to cont.
TOTAL IMPROVEMENT	**-5.3%**	**+0.9%**
IMPROVEMENT ON BOILER ISLAND ONLY	**0%**	**-0.1%**

Note 1: All improvements in the table are denoted by a negative number. All heat rate penalties are denoted by positive numbers. Note 2: Includes improvements achieved from 2000 through 2014.

Note 3: “BP” is defined as “Best Practices” and incorporates optimized operation and consistent maintenance to sustain the unit’s heat rate at its original design. BP prevents significant degradation of the unit’s performance.

Note 4: Although NN & ISB is technically applicable to this unit, no improvement is predicted due BP already employed.

Note 5: The fan improvements were made at the same time other improvements occurred on the unit; therefore, while some of the heat rate reduction is likely due to the ID/FD fan conversion to axial configuration, the remainder can be attributed to turbine maintenance and the discontinued use of the ESP.

Note 6: Although high efficiency fill has been added to the system and cooling tower fan blades have been modified, the change in heat rate is unknown. It is assumed that due to the problems with the high efficiency fill, the net heat rate has changed very little.

Table 6: Summary of Heat Rate Changes for Unit B3 (Existing and Potential) *Note 1*

Heat Rate Improvement	**% Change Achieved to Date** Note 2	**Future Potential % Change**
Boiler Island		
Material Handling	-0.1%	N/A
Boiler Operation/Overhaul with New Heat Transfer Surface	0%	BP to cont. Note 3
Neural Network & Intelligent Sootblowers	0%	BP to cont. Note 4
Air Pre-Heater		
Reduce Air Heater Leakage	0%	BP to cont.
Reduce Flue Gas Acid Dew Point	0%	N/A
Turbine Island		
Turbine Overhaul	-1.8%	0%
Feedwater Heaters	0%	BP to cont.
Condenser	0%	BP to cont.
Boiler Feed Pumps	0%	BP to cont.
Flue Gas System		
FD and ID Fan Efficiency	0%	N/A
Primary Air Fans	0%	N/A
Air Pollution Control Equipment		
FGD System	N/A	N/A
SNCR System Note 5	N/A	+0.3%
Particulate Collection Device	-0.07%	N/A
Water Treatment System		
Boiler Water Treatment	N/A	BP to cont.
Cooling Towers	0% Note 6	N/A
Large Scale Motors	0%	BP to cont.
TOTAL IMPROVEMENT	**-1.97%**	**+0.3%**
IMPROVEMENT ON BOILER ISLAND ONLY	**-0.1%**	**0%**

Note 1: All improvements in the table are denoted by a negative number. All heat rate penalties are denoted by positive numbers. Note 2: Includes improvements achieved from 2000 through 2014.
Note 3: “BP” is defined as “Best Practices” and incorporates optimized operation and consistent maintenance to sustain the unit’s heat rate at its original design. BP prevents significant degradation of the unit’s performance.
Note 4: Although NN & ISB is technically applicable to this unit, no HRI is predicted due to BP already employed.
Note 5: While SNCR systems are not considered for heat rate improvement, the added AQCS equipment does have an impact on the unit heat rate.
Note 6: Although high efficiency fill has been added to the system and cooling tower fan blades have been modified, the change in heat rate is unknown. It is assumed that due to the problems with the high efficiency fill, the net heat rate has changed very little.

Based on the site-specific constraints, AQCS equipment, operating and maintenance practices, and other unit-specific constraints, the units are predicted to have 0.9%, 0.9%, and 0.3% potential heat rate degradation in the future, respectively. This is compared to the approximately 5.6%, 5.3%, and nearly 2% heat rate improvement, respectively, that has occurred between 2000 and the date of this study. Overall, due to the improvements already made to the units, no future potential heat rate improvement is available for any unit at Station B, which means these units will not achieve the 2.1% heat rate improvement basis for the Western Interconnection.

6.0 Example State Compliance

Emission standards are based on achieving 1,305 lb CO_2/MWh-net at existing coal units and 771 lb CO_2/MWh-net at NGCC units. EPA used these subcategory-specific emission rates to develop the state-specific emission goals. To establish the state goals, the EPA applied the subcategory-specific rates to the baseline generation levels (i.e., percent fossil steam and percent NGCC) to estimate the affected fleet emission rate that would occur if all affected EGUs in the fleet met the subcategory-specific rates. EPA also established mass-based CO_2 performance goals for each state. Mass-based goals represent the emissions associated with compliance with the subcategory-specific performance rates and historical generation levels. Each state-specific emission amount is the product of the fossil steam EGU performance rate and historical fossil steam EGU generation, added to the product of the NGCC emission performance rate and historical NGCC generation.

To understand the effect the rule would have on units in State 'X', S&L analyzed the fleet for said state. The emission rate goal in 2030 for the state is 1,031 lb CO_2/MWh-net and is based on a fleet of approximately 51% NGCC capacity and 49% coal capacity (including oil/gas steam turbines, OGST). The mass-based goal in 2030 is 30,170,750 short tons, which is based on the goal rate applied to 2012 generation numbers with projected added capacity. Based on the analysis conducted, it is assumed that the EPA considered there would be over 3,193,000 MWh of added capacity by 2030 counted toward the state's final goal.

	# of Units	Fleet Capacity	2012 Electric Generation	CO_2 Mass	CO_2 Rate	Capacity Factor	Steam Capacity
		MW	MWh	Tons	lb/MWh	%	%
Coal	12	4,108	24,336,000	27,598,000	2,293	68	49
OGST	12	1,317	1,035,000	808,000	1,498	9	
NGCC	61	11,202	26,783,000	12,059,000	918	27	51
Renewable	131	5514	7,992,000			17	
Hydro	44	2919	6,796,000			27	
Solar	82	2008	947,000			5	
Wind	5	587	249,000			5	

An analysis was then completed to determine two possible ways to achieve each goal using the three building block strategies. To comply with the mass-based goal, HRI strategies could be applied to each coal-fired EGU. However, the mass-based goal requires a 25% reduction from baseline by 2030. Therefore, even if the coal-fired units could achieve the EPA expected 2.1% HRI for the western interconnect, the state would still be required to provide a significant portion of its CO_2 reduction via BB2 and BB3. To achieve the mass-based goal, without decreasing fossil fuel generation, BB2 is used heavily. Approximately 16,310,000 MWh would be expected to switch from coal generation to NGCC generation by 2030. This would increase NGCC capacity factor from 27 to 44%, while decreasing coal generation capacity factor from 68 to 25%. All potential heat rate improvement is expected to be negated by the drastic decrease in annual capacity factor due to reasons described in Section 3. Since adding more renewable power supply will not change the overall mass of CO_2 being emitted, BB3 does not have an effect on this example strategy.

Table 7: State X Compliance Strategy 1

	2012 Baseline			BB2 Adjustment			Rate
	MWh	CF	CO_2 tons	MWh	CF	CO_2 tons	lb/MWh
Coal + OGST	25,371,000	68	28,406,000	9,060,000	25	10,386,125	
NGCC	26,783,000	27	12,059,000	43,094,000	44	19,784,625	
Total	52,154,000		40,465,000	52,154,000		**30,170,750**	**1,157**

Another option for State X is to abide by the rate-based goal, which would be heavily dependent on increasing state-wide renewable energy capacity. Using BB1, heat rate improvement is applied to all 12 coal-fired units. S&L had previously completed heat rate audits on 6 of the 12 coal units in the state. Therefore, for the units in which audits were performed, the HRI determined in the study was applied. The remaining 6 units were assumed to be able to achieve the average of the 6 audits, or 1.22%. From here, BB2 was used to increase NGCC capacity. However, unlike the previous strategy explored, coal capacity factors were taken into consideration. It was assumed that the coal-fired units could reduce annual capacity factor to 55% from the previous 67% while maintaining similar unit heat rates. This is done to avoid negation of heat rate improvement strategies. To maintain fossil fuel generation, 5,578,000 MWh were switched from coal to NGCC units. NGCC thereby increased capacity factor from 27 to 33%.

Finally, BB3 is applied. While the CO_2 emissions are now set, renewable generation is increased to determine how much is necessary to achieve the 1,031 lb/MWh rate-based goal. It was determined that approximately 12,700,000 MWh of additional renewable capacity is required. This could be achieved two ways; assuming capacity factor could be increased or building new generation facilities. To achieve the increased annual generation without building new facilities, capacity factor would have to be increased from 17 to 43%. While some increases in capacity factor can be achieved by limiting maintenance outages, it is unlikely to increase by 250%. The other option is to build new renewable facilities and expect similar capacity factors moving forward. Based on the baseline 17% capacity factor, approximately 8,750 MW of new renewable energy facilities would be required.

Table 8: State X Compliance Strategy 2

	2,012 Baseline			BB1 Adjustment			BB2 Adjustment			BB3 Adjustment			Rate
	MWh	CF	CO_2 tons	MWh	CF	CO_2 tons	MWh	CF	CO_2 tons	MWh	CF	CO_2 tons	lb/MWh
Coal + OGST	25,371,000	68	28,406,000	25,371,000	68	27,243,000	19,793,000	55	22,690,000	19,793,000	55	22,690,000	
NGCC	26,783,000	27	12,059,000	26,783,000	27	12,059,000	32,361,000	33	14,857,000	32,361,000	33	14,857,000	
Renewable	7,993,000	17	0	7,993,000	17	0	7,993,000	17	0	20,682,000	43	0	
Total	60,147,000		40,465,000	60,147,000		39,302,000	60,147,000		37,547,000	72,836,000		**37,547,000**	**1,031**

7.0 Conclusion

Based on the various case studies performed in this study in combination with other similar studies S&L has recently conducted analyzing other coal-fired units, it appears that most of the utilities among the coal-fired fleet are already employing best operational and maintenance practices. This limits the future additional HRI at these already well-performing units. For many units, significant further reduction in heat rate, such as the EPA's 2.1-4.3% target from the 2012 baseline, may not be feasible. Various limitations exist for applying each heat rate improvement strategy, depending on the unit type, fuel type, and many other site-specific conditions. Therefore, the ability to apply each strategy and the amount of heat rate reduction that can be achieved by each strategy is site-specific and must be evaluated on a case-by-case basis.

In addition, the performance of some of the evaluated HRI strategies degrades over time, even with best maintenance practices. Therefore, depending on the HRI strategy employed or the technology installed, the unit heat rate initially obtained may increase over time. Furthermore, heat rate is increased when plants operate at lower loads, and the benefit of an HRI strategy is reduced at lower loads. If an existing EGU is currently base-loaded and shifts to load-cycling operation in the future, due to Block 2 or 3, that unit's annual average heat rate will increase. In some cases any HRI improvements achieved could be completely negated by HRI losses associated with load-cycling. The installation of additional AQCS such as that required by regulations including BART, ELG, MATS, etc. will also increase the heat rate of units compared to its heat rate prior to installation due to the use of auxiliary power.