# COAL FIRED POWER PLANT HEAT RATE REDUCTION – NRECA

## SL-012541

NOVEMBER 21, 2014
PROJECT NO. 13276-001

PREPARED BY

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## CONTENTS

# CONCLUSIONS

- Sargent & Lundy's 2009 Report does not conclude that any individual coal-fired EGU or any aggregation of coal-fired EGUs can achieve 6% heat rate improvement (HRI) or any broad target, as assumed by the EPA.

- The results in the 2009 Report were mostly based on publicly available data, data from original equipment manufacturers, and Sargent & Lundy's power plant experience. Furthermore, the case studies showed that not all of the examined alternatives were feasible to apply to an individual generating unit due to a number of factors, including plant design, previous equipment upgrades, and each plant's operational restrictions.

- Various limitations exist for applying each heat rate improvement strategy, and these limitations depend 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.

- It appears as though the EPA concluded that heat rate improvements cited in the 2009 Report were additive and applicable to all coal-fired units. Heat rate improvement ranges described in the 2009 Report case studies were estimated at a conceptual level, and were not based on detailed site-specific analyses. Verification of actual heat rate improvements was not made to determine whether any of the strategies were implemented and what actual heat rate improvements were realized based on site-specific design.

- Combinations of strategies to achieve heat rate improvements do not always provide heat rate improvement reductions equal to the sum of each individual strategy's heat rate improvement because many of the technologies affect, or are dependent upon, plant operating variables that are inter-related. Therefore, case-by-case analyses must be conducted to determine whether the incremental heat rate improvement through the application of multiple strategies is economically justified.

- The performance of some of the evaluated heat rate improvement strategies degrades over time, even with best maintenance practices. Therefore, depending on the strategy employed or the technology installed to reduce heat rate at an existing coal-fired EGU, the unit heat rate initially obtained may increase over time.

- Heat rate is increased when plants operate at lower loads, and the benefit of a heat rate improvement strategy is reduced at lower loads. Therefore, if an existing EGU is currently base-loaded and shifts to a load-cycling operating profile in the future, that unit's annual average heat rate will increase, and the heat rate reduction strategy (or strategies) implemented will not lower the annual average heat rate as much as compared to base-load operation. In some cases any HRI improvements achieved by undertaking the relevant options described in S&L's 2009 Report could, in some cases, be completely negated by HRI losses associated with load-cycling.

- The installation of additional pollution controls such as that required by regulations including BART, MATS, etc. will increase the heat rate of any unit as compared to its heat rate before the installation due to the use of auxiliary power.

- Many of the options for HRI listed in the 2009 Report have triggered New Source Review actions by EPA and others.

- Based on the case studies performed by S&L, subsequent to the 2009 Report, it appears that most of the utilities are employing best operational and maintenance practices.

- The five-unit case study performed in development with this study estimate that on a weighted average, approximately 1.2% improvement has been achieved to date, while 0.3% improvement is potential for the future for over 2,500 $MW_{NET}$ power generation. Future improvement strategies are limited, due to sufficient amount of previous improvements already performed on these units. In light of this observation in combination with other similar studies S&L has recently conducted analyzing other coal-fired units, it appears that an aggregate 6% reduction in heat rate, such as that assumed by the EPA from the 2012 baseline, may not be feasible.

- Furthermore, if improvement options are limited to the boiler island, the weighted average past and future potential heat rate improvement for the five units is approximately 0.04% and 0.08%, respectively, which would be impossible to verify.

# EXECUTIVE SUMMARY

On June 18, 2014, United States Environmental Protection Agency (EPA) published the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule" in the *Federal Register* (79 Fed. Reg. page 34830). EPA analyzed potential $CO_2$ emission reductions associated with various "building blocks" that affect the power generating industry. 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 natural gas combined cycle units; (3) expanded use of renewable energy resources; and (4) expanded use of demand-side energy efficiency. The EPA concluded "that a six percent reduction in the $CO_2$ emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at a reasonable cost" (79 FR 34861). 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 report. 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.

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 ES-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.<br>- 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.<br>- Any increase in steam flow may also require increase in coal flow thus possibly triggering NSR under some circumstances.<br>- Periodic replacement to recover the steam generation capacity of the unit does not yield any increase in efficiency.<br>- Units (limited number) required to add economizer surface area to lower temperatures at full load to prevent sintering of SCR catalyst must frequently also raise temperatures at lower loads to prevent ammonium salt deactivation of the |

| HRI Method | Limitations |
|---|---|
| | 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.<br>- 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.<br>- 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.<br>- 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.<br>- 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.<br>- 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<br>- 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.<br>- 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. |
| (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. |

| HRI Method | Limitations |
|---|---|
| (9) Condenser | - Many units already employ BP*, thereby negating further heat rate improvement.<br>- 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.<br>- 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.<br>- Not applicable for use on axial fans.<br>- 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.<br>- Applicability is limited to WFGDs operating at lower than design sulfur or lower than full load.<br>- Plans reducing heat rate through FGD modifications, such as operating bypasses or scrubbing the flue gas less efficiently, often risk emission increase.<br>- 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.<br>- Is not applicable for units with baghouses. |
| (14) Selective catalytic reduction (SCR) system | - Minimal efficiency gain compared to total retrofit work required.<br>- Recently designed/installed SCRs already have completed rigorous computational fluid dynamics (CFD) modeling to optimize pressure drop.<br>- 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.<br>- Heat rate improvement is likely not better than BP* associated with condenser cleaning. |

| HRI Method | Limitations |
|---|---|
| (16) Cooling tower: | - Many units among the fleet have already implemented counter-flow configurations.<br>- 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 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.

Block 2 of the EPA's $CO_2$ reduction strategy stated in the draft regulation, requires increasing generation dispatch to natural gas combined cycle (NGCC) units, due to the lower $CO_2$ emission rate (in lb/MMBtu) that is associated with natural gas.[1] 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. 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.

Pursuant to the proposal, each state would be required to achieve their interim goals over a 10-year average between 2020 and 2029, 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 report, 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

[1]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.

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. Therefore, performance degradation should be accounted for when considering certain HRI technologies as part of a long-term sustainable heat rate improvement strategy.

The EPA suggests restricting unit dispatch to avoid triggering new source review (NSR).[2] 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.

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. 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. 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 report. The heat rate improvement of the boiler island only was limited to 0.1% in the future for both units, with 0% and 0.5% that has occurred to date for Unit A1 and A2, respectively.

Three units comprising "Station B" were analyzed, Units B1, B2, and B3. 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. No future potential heat rate improvement is available. 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 report. The heat rate improvement on the boiler island only is limited to 0.1% in the future for Units B1 and B2, with none that has occurred to date. Unit B3 has achieved 0.1% heat rate reduction to date on the boiler island only, with no potential in the future.

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

Based on the various case studies performed in this report 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 employing best operational and maintenance practices. For many units, significant further reduction in heat rate, such as 6% assumed by the EPA from the 2012 baseline, may not be feasible.

Sargent & Lundy's 2009 Report does not conclude that any individual coal-fired EGU or any aggregation of coal-fired EGUs can achieve a broadly applied target outlined by the EPA. 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.

# 1. INTRODUCTION

## 1.1. Purpose

On June 18, 2014, United States Environmental Protection Agency (EPA) published the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule" in the *Federal Register* (79 Fed. Reg. page 34830). The proposed rule does not set emissions standards for individual sources, but provides guidelines for states to follow in developing plans to address greenhouse gas (GHG) emissions from existing sources in and beyond the power sector. Specifically, EPA proposed to establish state-specific rate-based (or mass-based) goals for carbon dioxide ($CO_2$) emissions. Proposed emission goals vary from state to state.

To establish the state-specific rate-based $CO_2$ emission goals, EPA analyzed potential $CO_2$ emission reductions associated with various "building blocks" that affect the power generating industry, including reducing $CO_2$ emissions (i.e., lb $CO_2$/MW-net) at individual affected electric generating units (EGUs) through heat rate improvements.

The purpose of this engineering study is to conduct a review for The National Rural Electric Cooperative Association (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. The purpose is demonstrated by conducting heat rate improvement audits on two power plants with a total of five units, generating approximately 2,500 $MW_{NET}$.

## 1.2. Study Scope

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. Because of the diverse nature of utilities and units that comprise NRECA, and because of the highly site-specific applicability and performance of heat rate improvement technologies, the scope of this engineering study includes:

- A discussion of major limitations in applying each technology at operating units
- A discussion of limitations for combinations of technologies to achieve heat rate improvements
- An analysis of how load cycling impacts heat rates in operating units
- A discussion of the heat rate improvement technologies potential to degrade in performance over time
- A discussion of the potential for various heat rate improvement technologies to trigger NSR
- Heat rate improvement case studies that explore previous and potential future heat rate improvements Station A and Station B within the NRECA fleet for a total of five units.

It should be noted that the scope of this report does not include any detailed design work. Should any of the units within the NRECA electric cooperative membership implement any of the technologies identified as potentially improving heat rate, detailed design work may reveal additional site-specific limitations in either the applicability of the technology or the achievability of heat rate reduction.

# 2. The Heat Rate Improvement (HRI) Building Block

In the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule," state-specific rate-based goals were proposed by EPA. EPA analyzed potential $CO_2$ emission reductions associated with various "building blocks" that affect the power generating industry. The building blocks included: (1) reducing $CO_2$ emissions (i.e., lb $CO_2$/MW-net) at individual affected coal-fired EGUs through heat rate improvements; (2) $CO_2$ emission reductions achievable through re-dispatch from coal-fired units to natural gas combined cycle units; (3) expanded use of renewable energy resources; and (4) expanded use of demand-side energy efficiency.

To establish each state's rate-based $CO_2$ emissions goal, EPA concluded "that a six percent reduction in the $CO_2$ emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at a reasonable cost" (79 FR 34861). The EPA has stated that this reduction would be applied to all units in the nation-wide fleet, rather than determining a potential reduction rate on a state-wide or unit-by-unit basis. The average 6% heat rate improvement (using 2012 as the baseline year) was determined by the EPA based on their evaluation of heat rate improvements that may be achieved at existing coal-fired EGUs through the adoption of "best practices" and equipment "upgrades." Heat rate improvements that may be achieved by adopting best practices and equipment upgrades as defined by the EPA 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 report.[3] The following section summarizes the 2009 Report and discusses EPA's interpretation of it.

## *2.1. 2009 Report Summary*

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. The 2009 Report identified a range of conceptual Btu/kWh heat rate improvement projects, including boiler improvements, steam turbine improvements, control system improvements, high efficiency motors, and similar improvements known to result

[3] The topic of "best practices" definition is discussed further in Section 2.2.

in system efficiency gains. A list of the heat rate improvement projects considered in the 2009 Report is shown in Table 1.

**Table 1: S&L Identified Heat Rate Reduction Strategies from 2009 Report**

| Heat Rate Reduction Strategies | |
|---|---|
| Boiler Island | |
| 1 | Coal transport, conveying, and grinding [4] |
| 2 | Boiler operation/overhaul with new heat transfer surface |
| 3 | Neural network (NN) control system |
| 4 | Intelligent sootblower (ISB) system |
| 5 | Air heater leakage mitigation |
| 6 | Air heater acid dew point reduction |
| Turbine Island | |
| 7 | Turbine overhaul and upgrade |
| 8 | Feedwater heater[1] |
| 9 | Condenser cleaning |
| 10 | Boiler feed pump rebuild |
| Flue Gas System | |
| 11a | Forced draft (FD) and induced draft (ID) fan improvement |
| 11b | Variable-frequency drive (VFD) |
| Air Pollution Control Equipment | |
| 12 | Flue gas desulfurization (FGD) system modifications |
| 13 | Particulate system modifications |
| 14 | Selective catalytic reduction (SCR) system modifications |
| Water Treatment System | |
| 15 | Boiler water treatment[1] |
| 16 | Cooling tower advanced packing |

For each alternative, S&L estimated the potential heat rate improvement that may be achieved at a 200, 500, and 900 MW coal plant. These 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 at full load. Minimum and maximum ranges are meant to reflect site-specific differences. The estimates do not account for normal degradation that occurs in some equipment retrofits. No excess retrofit factors were taken into account nor were any impacts due to combination of technologies. In addition, these values are meant to represent a range only if the methods are applicable to the unit. If the technology is not applicable, the improvement is assumed to be zero. Table 2 shows the range of heat rate improvements that were estimated in the 2009 Report.

[4] Although these strategies were included in the discussion of S&L's 2009 Heat Rate Reduction study, the EPA did not include them as part of their HRI methods.

**Table 2: Summary of Heat Rate Reductions from S&L Study SL-009597**

| | Heat Rate Reduction (Btu/kWh) | | | | | |
|---|---|---|---|---|---|---|
| | 200MW | | 500 MW | | 900 MW | |
| **New Heat Transfer Surface** | 50 | 100 | 50 | 100 | 50 | 100 |
| **Neural Network** | 50 | 150 | 30 | 100 | 0 | 50 |
| **Intelligent Sootblowers** | 30 | 150 | 30 | 90 | 30 | 90 |
| **Air Heater Leakage** | 10 | 40 | 10 | 40 | 10 | 40 |
| **Acid Dew Point Reduction** | 50 | 120 | 50 | 120 | 50 | 120 |
| **Turbine Overhaul** | 100 | 300 | 100 | 300 | 100 | 300 |
| **Condenser Maintenance** | 30 | 70 | 30 | 70 | 30 | 70 |
| **Boiler Feed Pump Maintenance** | 25 | 50 | 25 | 50 | 25 | 50 |
| **Fan & Motor Improvements** | 10 | 50 | 10 | 50 | 10 | 50 |
| **VFD Only** | 20 | 100 | 20 | 100 | 20 | 100 |
| **WFGD Modifications** | 0 | 50 | 0 | 50 | 0 | 50 |
| **Particulate System Modifications** | 0 | 5 | 0 | 5 | 0 | 5 |
| **SCR Modification** | 0 | 10 | 0 | 10 | 0 | 10 |
| **Advanced Cooling Tower Packing** | 0 | 70 | 0 | 70 | 0 | 70 |

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. The selection of the units involved in the case studies were not planned to represent a "typical" unit, nor were they meant to represent simple or difficult retrofits cases. These units were merely selected based on in-house studies previously performed. Each unit should be analyzed on a unit-by-unit basis; these case studies are meant to represent two possible scenarios and guide the reader on the proper methodology for the use of identified technologies. Table 3 summarizes the heat rate improvement projects evaluated to be technically feasible at the 250 MW unit, the estimated potential reduction in heat rate, and the associated order-of-magnitude costs for each technology evaluated. Table 4 summarizes the heat rate improvement projects evaluated to be technically feasible at the 850 MW unit, the estimated potential reduction in heat rate, and the associated order-of-magnitude costs for each technology evaluated. For each unit, site-specific technology constraints were used to determine conceptual level improvement rates and overall unit reduction. Some of these constraints include already performing best operation and maintenance practices, already having made equipment improvements, or not having eligible AQCS equipment. If the method was not applicable, no heat rate reduction was considered. The case studies illustrate that with more constraints, lower heat rate improvement results, if it is applicable at all.

**Table 3: Summary of Case Study #1 Results (250 MW Unit)**

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

**Table 4: Summary of Case Study #2 Results (850 MW Unit)**

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

As can be seen from Tables 3 and 4, the difference in heat rate reduction is significant. This is due to the overall site constraints and resulting applicability of the 16 methods. Since there were more available improvements for the smaller unit in this case study, it is possible to achieve a higher heat rate improvement. It is important to note that the majority of the heat rate improvement comes from installing new air heaters, steam turbine upgrades, and boiler feed pump, all of which are subject to normal performance degradation. Therefore, 4% represents the potential improvement at full load after the technologies are initially installed. These numbers are not meant to represent achievable values for all units of these sizes within the U.S. fleet. Instead, these numbers are meant to show the variability of heat rate improvements among the fleet.

Heat rate improvements ranges described in the 2009 Report case studies were estimated at a conceptual level, and were not based on any site-specific detailed analysis. The results were mostly based on publicly available data, data from original equipment manufacturers, and Sargent & Lundy's power plant experience. In addition, verification of actual heat rate improvements was not made to determine whether any of the improvement strategies were implemented and what actual heat rate improvements were realized based on detailed design. Therefore, it is possible that the ranges provided may not be achievable depending on additional limitations.

### *2.2. EPA's Use of the 2009 Report*

EPA reviewed S&L's heat rate reduction methods and used the average $/kW value for each option to rank the strategies from low- to no-cost options up to high capital costs options. This ranking can be found in Table 2-13 of the Technical Support Document (TSD) entitled "GHG Abatement Measures."

**Figure 1: Table 2-13 from the EPA's TSD**

| No-Cost and Low-Cost Options |
|---|
| Condenser Cleaning |
| Intelligent Soot Blowers |
| ESP Modification |
| Boiler Feed Pump Rebuild |
| Air Heater and Duct Leakage Control |
| Neural Network |
| SCR System Modification |
| FGD System Modification |
| Cooling Tower Advanced Packing |
| |
| Higher Cost Options |
| Economizer Replacement |
| Acid Dew Point Control |
| Combined VFD and Fan |
| Turbine Overhaul |

The nine lowest options were considered to be part of what the EPA calls "best practices" while the remaining four high-cost options are considered to be "upgrades". According to the EPA "best practices include no-cost or low-cost methods such as the installation or more frequent tuning of control systems and the in-kind replacement of worn existing components. Upgrades often involve higher costs and greater downtime, such as, extensive overhaul or upgrade of major equipment (turbine or boiler) or replacing existing components with improved versions." Although many of the "best practices" options provided in the list are strictly dependent on employing optimized operating and maintenance practices (e.g., turning off unneeded pumps, installation of digital controls systems, earlier in-kind replacement of worn components, etc.), some of the options include large project capital and/or physical changes. However, the heat rate improvement achieved after repairs during outages may not be sustainable. The term "best practices" implies procedural changes rather than equipment changes; therefore, S&L believes the following technologies would be better considered as equipment upgrades rather than best practices:

- NN
- ISB
- Installation of EMS on ESP
- SCR system optimization
- FGD system optimization (including additional flow correction devices)
- Advanced cooling tower packing

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. Furthermore, the case studies provided in the 2009 Report showed that it would not be feasible to apply all of the examined alternatives from the study to an individual generating unit due to a number of factors, including plant design, previous equipment improvements, and operational approaches. 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.

# 3. HRI STRATEGY LIMITATIONS

When evaluating heat rate reduction strategies, it is important to consider the limitations of each HRI strategy. The type of fuel burned at a unit can impact the potential HRI methods because heating value, sulfur content, and moisture content are important components that affect a plant's heat rate. The age of a power plant will also affect the applicability of HRI methods. Units designed in the last 10-15 years were designed with the lowest possible heat rate for supercritical and subcritical steam cycles. Newer units will likely have the most efficient equipment/configuration already implemented; cross-flow cooling towers, dense pack turbine, VFDs on fans, etc. Site spatial constraints can also play a role in heat rate improvement project options, including access issues and available square footage. Finally, installing some types of air pollution control equipment may limit the applicability of some HRI strategies or even lead to net heat rate increases. Additionally, the installation of additional pollution controls such as that required by regulations including BART, MATS, etc. will increase the net unit heat rate (NUHR) of any unit as compared to its NUHR before the installation due to use of auxiliary power.[5]

## *3.1. Summary of Limitations*

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. It is recommended that each site/unit is looked at individually to determine which units have more site specific limitations.

**Table 5: Heat Rate Improvement Method Limitations**

| HRI Method | Limitations |
|---|---|
| **Boiler Island** | |
| (1) Coal transport, conveying, and | - Minimal efficiency gain compared to total retrofit work required.<br>- Spatial constraints may limit applicability. |

[5] The mercury air and toxics standard (MATS) limits the emissions of hazardous air pollutants to a specific rate. A best available retrofit technology (BART) study requires an analysis to determine the best individual solution for a station to comply with standards such as Regional Haze.

| HRI Method | Limitations |
|---|---|
| grinding | |
| (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.<br>- Any increase in steam flow may also require increase in coal flow thus possibly triggering NSR under some circumstances.<br>- Periodic replacement to recover the steam generation capacity of the unit does not yield any increase in efficiency.<br>- Units (limited number) required to add economizer surface area to lower temperatures at full load to prevent sintering of SCR catalyst 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.<br>- 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.<br>- 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.<br>- 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.<br>- 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 potentially to avoiding plugging, cannot implement this technology.<br>- 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<br>- Units burning 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 |

| HRI Method | Limitations |
|---|---|
| | improvement.<br>- Due to large size of LP turbine section, and limited impact in comparison with the HP section, improvement is typically outweighed by performance payoff. Therefore, this improvement is not typically performed for heat rate purposes. |
| (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.<br>- Units with recently improved mechanical cleaning systems will not significantly benefit from condenser cleaning. |
| (10) Boiler feed pump | - Units with recently rebuilt boiler feed pumps will not benefit from further improvement.<br>- 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 replaced or improved their ID fans recently, have already incorporated VFDs on their centrifugal.<br>- Not applicable for use on axial fans.<br>- 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.<br>- Applicability is limited to WFGDs operating at lower than design sulfur or lower than full load.<br>- Plans reducing heat rate through FGD optimizations, such as operating bypasses or scrubbing the flue gas less efficiently, often risk emission increase.<br>- Not applicable to dry or semi-dry FGD, as well as jet bubbling reactor (JBR) or venturi scrubber WFGDs. |
| (13) Particulate system | - Implementing EMS systems is likely not feasible while maintaining FPM emission limits established by MATS.<br>- Is not applicable for units with baghouses. |
| (14) Selective catalytic reduction (SCR) system | - Minimal efficiency gain compared to total retrofit work required.<br>- Recently designed/installed SCRs already have completed rigorous computational fluid dynamics (CFD) modeling to optimize pressure drop.<br>- Applicability is limited to units with existing SCRs. |

| HRI Method | Limitations |
|---|---|
| **Water Treatment System** | |
| (15) Boiler water treatment | - Many units already have a modern water treatment system to reduce scaling.<br>- 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.<br>- Improvements to cooling towers may have spatial constraints. |

*Note: If a unit employs best operational and maintenance practices (BP) 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.

### *3.2. Unit Categorization*

As previously discussed, achievable heat rate depends highly on the type and site of boiler and the type of fuel. In general, units can be categorized by boiler type (supercritical or subcritical), fuel type (lignite/subbituminous or bituminous), and nameplate unit size (large, medium, or small unit).[6] Each of these categories within the electric cooperative coal-fired fleet was explored to understand the impact on baseline $CO_2$ emissions.

**Table 6: NRECA Fleet Categorization**

| | Large Supercritical | Large Subcritical | Medium Supercritical | Medium Subcritical | All Small Units |
|---|---|---|---|---|---|
| **Lignite & Subbituminous** | | | | | |
| # of Units | 3 | 28 | 1 | 25 | 2 |
| Total MW | 2,329 | 19,313 | 346 | 7,834 | 224 |
| lb $CO_2$/MWh-gross | 1,836 | 2,124 | 2,123 | 2,105 | 2,312 |
| **Bituminous** | | | | | |
| # of Units | 7 | 7 | -- | 17 | 19 |
| Total MW | 4,156 | 5,437 | -- | 5,058 | 2,067 |
| lb $CO_2$/MWh-gross | 1,929 | 1,982 | -- | 2,021 | 2,210 |

The units with the lowest $CO_2$ emissions are the large supercritical units, which have the fewest opportunities to lower the plant heat rate. Supercritical units have a slight advantage in $CO_2$ emissions, due to operating at higher

[6] Large units are considered units greater than 500 MW. Medium units are those which are between 200-500 MW. Small units are anything below 200 MW of nameplate generation capacity.

load points throughout the year and overall more efficient cycle. It was expected that subbituminous and lignite fuels would have a higher $CO_2$ emission rate, due to the lower boiler efficiency and higher auxiliary power consumption in comparison with bituminous fuel. However, this was not noticed, potentially due to most bituminous coal units being equipped with wet FGDs and SCRs. Among this fleet, there are no conclusions that can be drawn based on the fuel type, due potentially to the heat rate effects of other factors such as installation of AQCS equipment or plant locations.

# 4. COMBINATION OF HRI STRATEGIES

As discussed previously, the 2009 Report estimated ranges of potential heat rate improvements that could be achieved by applying various technologies. 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. This is because many of the technologies affect power plant operating variables that are related or dependent upon one another.

One example of a combination of technologies for which the combined heat rate reduction is lower than the sum of the individual heat rate reductions is the application of NN with ISB. The performance of each of these technologies relies on boiler performance variables that are related to one another, and their performance cannot be decoupled. Another example of overlapping effects would be combining condenser maintenance practices with state of the art boiler water chemistry. The optimization of boiler water chemistry is a strategy to keep deposits from forming inside the boiler feed loop. If very balanced cooling water chemistry is maintained, then deposits are less likely to form, and the heat rate improvement realized by maintenance practices such as condenser cleaning would be lower.

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.

# 5. IMPACT OF CYCLING ON HRI STRATEGIES

As part of the EPA's plan to reduce nationwide $CO_2$ emissions, it has incorporated a second block strategy that involves moving a certain percentage of dispatch from coal fired power plants to natural gas combined cycle (NGCC) power plants and a third block that promotes renewable energy. There is emission reduction that can be achieved by firing natural gas due to the lower $CO_2$ emission rate (lb/MWh); however, by decreasing dispatch to coal fired units, shifting units from base-loaded operation to a cycling load profile will increase those units' heat rates. 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. The reason this occurs is that boilers are designed to achieve their highest efficiency at full load. If units were to increase the amount of cycling required over a year, which will decrease their average operating capacity factor, their average heat rate will increase from their baseline rates. This section of the report explores the impact that dispatch has on electric cooperative unit heat rates. The identified impacts here should be the same for units throughout the industry fleet that undergo similar cycling.

## *5.1. Effect of Dispatch on Individual Strategies*

The limitations of individual heat rate improvements were discussed in Section 3. In addition, it should be determined how load profile impacts each of these strategies and determine whether increased unit cycling would limit these strategies as well.

The following table highlights how low load or cycling profiles will affect each of the HRI strategies.

**Table 7: Cycling Impacts on HRI Methods**

| HRI Method | Load Limitations |
|---|---|
| Boiler Island | |
| (1) Coal transport, conveying, and grinding | - As unit load decreases, plant auxiliary power decreases, but the auxiliary power consumed at lower loads is a higher percentage of the power generated. This leads to increased heat rates at lower loads. |
| (2) Boiler operation/overhaul with new heat transfer surface | - Maximum heat rate improvement potential is achieved at full load and decreases at lower loads; therefore, increasing unit cycling will reduce the overall benefit of added surface area. |
| (3) Neural network (NN) | - NN is unable to effectively limit excess air at low loads; therefore, |

| HRI Method | Load Limitations |
|---|---|
| control system | heat rate benefit is negligible at low loads. |
| (4) Intelligent sootblower (ISB) system | - Slag formation at low load does not negatively impact heat transfer due to high surface area |
| (5) Air heater leakage mitigation | - Decreased in-leakage potential at low load lowers gas volumes and auxiliary power associated with ID fan operation. However, benefits are largely negated by increased gas volumes due to operating at higher excess air at low loads. |
| (6) Air heater acid dew point reduction | - At low load, plants inherently operate closer to acid dew point; therefore, the benefits of lowering air heater outlet temperature at full load will not be available at low loads. |
| Turbine Island | |
| (7) Turbine overhaul and upgrade | - Maximum heat rate improvement potential is achieved at full load and continues to decrease at lower loads; therefore, increasing unit cycling will reduce the overall benefit of a turbine upgrade. |
| (8) Feedwater heater | - Replacement is determined by maintenance practices when excess tubes are plugged due to fouling; therefore, improvement effect is not based on load. |
| (9) Condenser | - Cleaning is determined by BP; therefore, improvement effect is not based on load. |
| (10) Boiler feed pump | - Depending on the nature of the pump operating curve, increased dispatch at low load will translate to decreased efficiency of pump operation, providing less heat rate improvement at low load. |
| Flue Gas System | |
| (11) a. Forced draft (FD) and induced draft (ID) fan improvement | - Centrifugal fans would be operated further from optimal efficiency at low loads, which would result in increased heat rate. Units with axial fans would have less heat rate increase at lower loads. |
| (11) b. Variable-frequency drive (VFD) | - VFD provides maximum benefit for units that cycle frequently, due to increased motor efficiency at lower loads; therefore, use of VFD on centrifugal fans could restore some of the heat rate increase based on the description in 11a. |

| HRI Method | Load Limitations |
|---|---|
| Air Pollution Control Equipment | |
| (12) Flue gas desulfurization (FGD) system[7] | - Depending on acid gas emission limits and plant operating procedures, taking a spray level out of service at low load may reduce flue gas pressure drop and aux power associated with slurry pumps. |
| (13) Particulate system[8] | - Depending on PM emissions margin, taking T/R sets out of service at lower loads would be beneficial for aux power reduction. Testing would need to be conducted to determine if the MATS emission limits were still achieved. |
| (14) Selective catalytic reduction (SCR) system | - Opportunities for decreased pressure drop at full load may not be as significant at low load. This provides minor impact to heat rate at low loads. |
| Water Treatment System | |
| (15) Boiler water treatment | - No limitation due to load changes as long as unit stays on-line. Increased oxygen ingress and resulting corrosion products are experienced when unit is forced to go through startup/shutdown. |
| (16) Cooling tower | - Maximum heat rate improvement potential is achieved at full load and continues to decrease at lower loads; therefore, increasing unit cycling will reduce the overall benefit of upgrading a unit's cooling tower. |

### *5.2. Varying Dispatch vs. Heat Rate Curves*

The electric cooperative coal-fired fleet is composed of more than 100 different units that all have different dispatch rates. The annual capacity factor may be lower in the future if EPA's building Block 2, requiring replacement of coal with NGCC, and Block 3, requiring the use of renewable energy, are implemented. 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.

[7] This HRI approach creates an opportunity to increase emissions with an increase in load if corrective action is not taken.
[8] *Id.*

The following units participated in this portion of the analysis:

- Hoosier Energy, Merom Units 1 & 2
- San Miguel Electric Cooperative (SMEC), San Miguel
- Sunflower Electric Power Corporation, Holcomb Unit 1
- Big Rivers Electric Corporation, Robert E. Green Units 1 & 2
- Arizona Electric Power Co-Op (AEPCO), Apache Unit 3
- Southern Mississippi Electric Power Association (SMEPA), Morrow Units 1 & 2

S&L requested hourly net load data along with either NUHR or heat input to the boiler. Net unit load ($MW_{NET}$) and heat input data were used to calculate heat rate in certain cases, while other plants provided S&L with heat rate data. Data were then categorized by 10% load increment "load bins" to determine load weighted average NUHR. The load increments were plotted against average NUHR to develop a single curve. This information provides insight as to actual operating heat rate curves for each unit, rather than an ideal design case at full load. Unit dispatch was plotted to provide insight as to what the recent average operating capacity factor (AOCF) was for each unit.[9] Along with developing a heat rate curve for each unit, the total hours of operation, total net generation, and load weighted NUHR was determined for each "load bins". This information also provided insight as to the average load at which units operated as well as the average NUHR for operating hours in a year. The outage durations were eliminated from this analysis. The following sections include the analysis of this data for each of the eight units listed above to determine the effect that different load operation had on unit heat rate. While the data explored is recent actual operating information from plants, changes to operations in the future may increase or decrease annual average NUHR based on dispatch. It is assumed that the unit load and heat input data provided from the continuous emissions monitors (CEMS) or plant database are accurate enough to report relative changes to heat rate at different loads.

[9] Rather than using annual capacity factor, the unit capacity factor was determined from an hours-of-operation basis. Therefore, the average operating capacity factor (AOCF) was developed: $AOCF = \dfrac{TotalAnnualMW}{MCRLoad \times TotalHoursofOperation}$

### 5.2.1. Merom Unit 1& 2

Merom Station is comprised of two coal-fired units located in Indiana. Each unit has a generation capacity of approximately 540 $MW_{GROSS}$ which translates into approximately 500 $MW_{NET}$. The units are subcritical and fire bituminous fuel. Both units recently underwent FGD retrofits that were completed in 2013 and 2012 for Units 1 and 2, respectively. Load and heat rate data was provided from the time of FGD commissioning through the end of 2013. Therefore 6 months of data was provided for Unit 1 and 1.5 years of data was provided for Unit 2.

Figures 2 and 3 show that the units typically operate between 325-500 $MW_{NET}$. The station has reported that the unit is not dispatched below 240 MW. The AOCF for Unit 1 was approximately 85% when looking at periods of time when the unit was not in an outage in 2013. The Unit 2 AOCFs are 76% and 83% for 2012 and 2013, respectively.

**Figure 2: Merom Unit 1 - 2013 Dispatch**

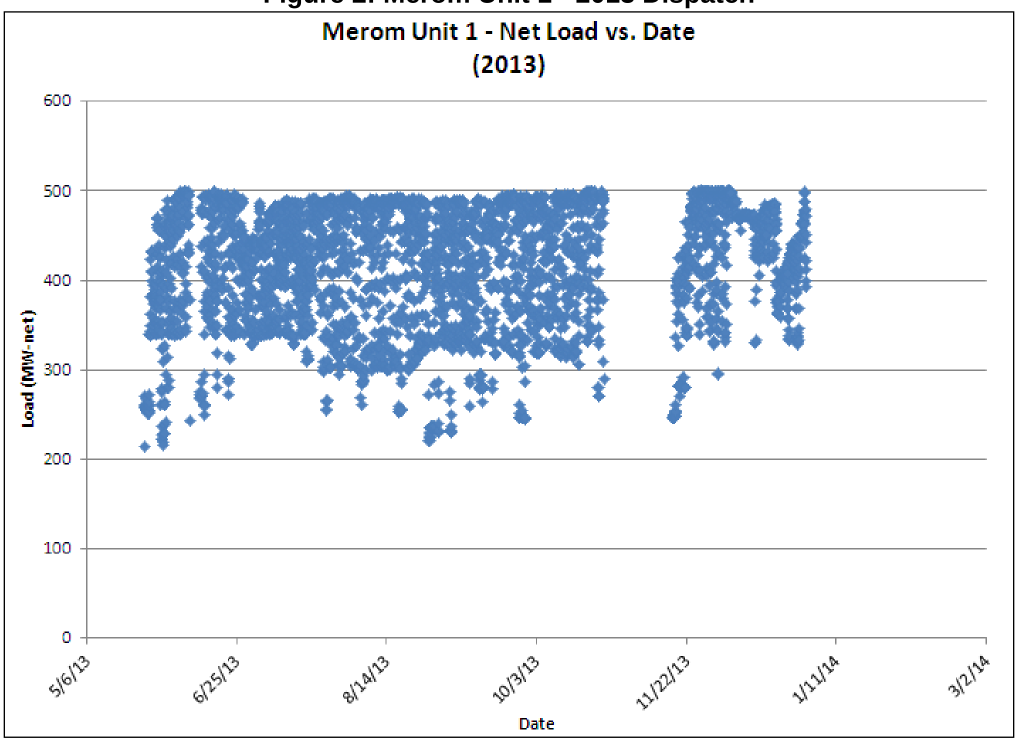


**Figure 3: Merom Unit 2 - 2012-2013 Dispatch**

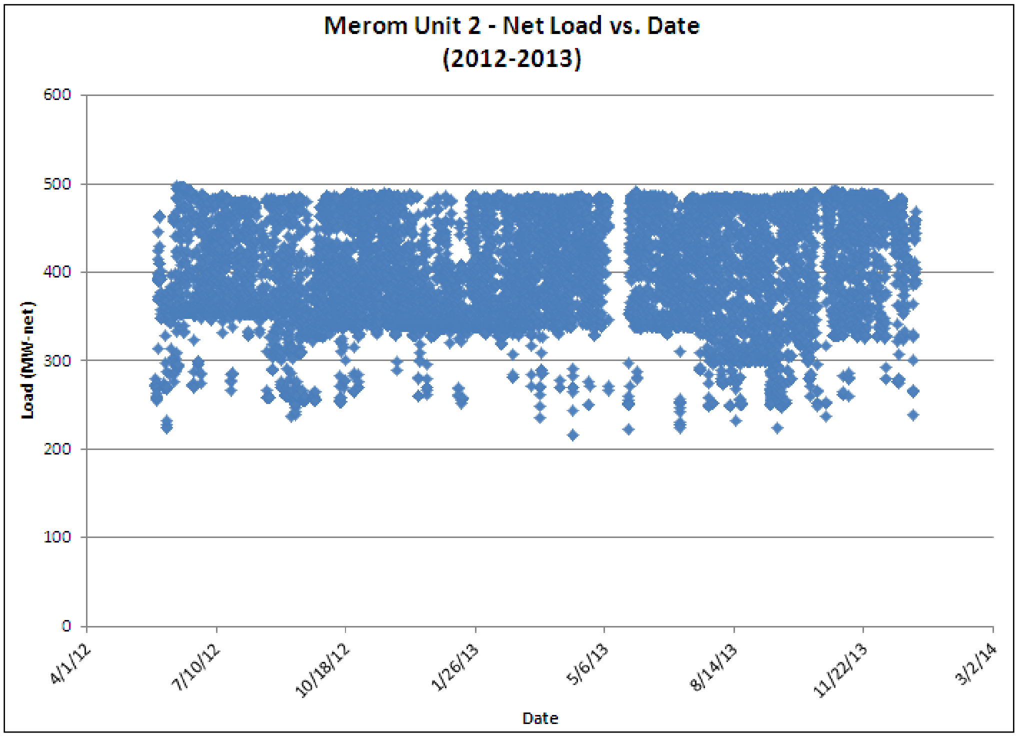



**Figure 4: Merom Unit 1 - Weighted Average Heat Rate Curve**

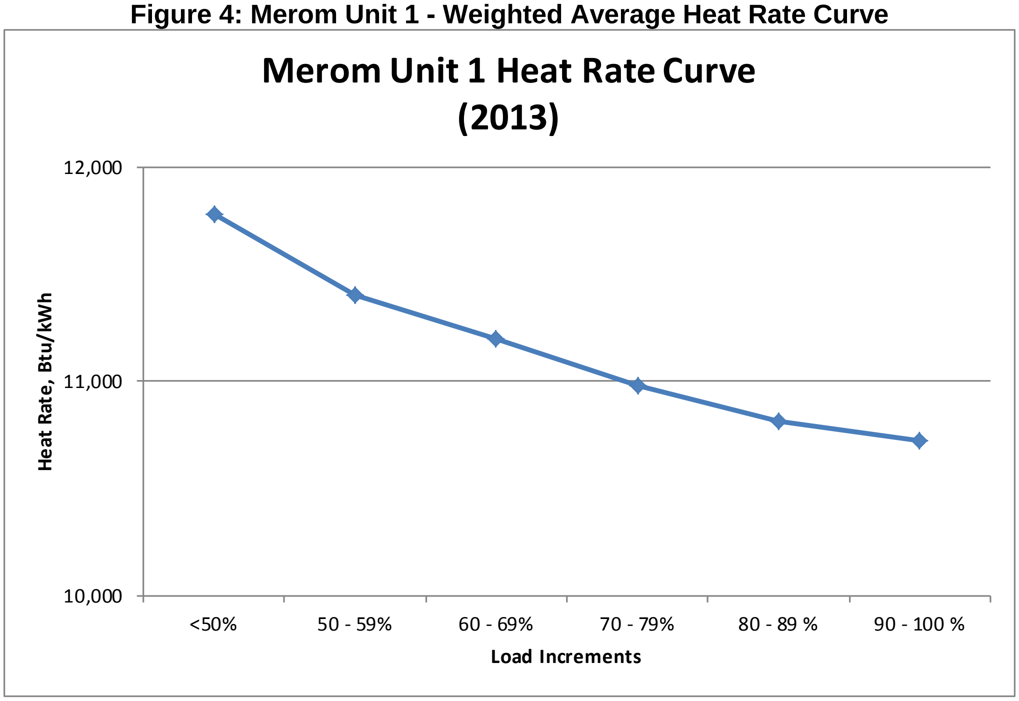


**Table 8: Merom Unit 1 - 10% Load Increments**

| Load Increment | Net Load Increment ($MW_{NET}$) | # of Operating Hours (hours) | Total Generation (MW) | Average NUHR (Btu/kWh-net) |
|---|---|---|---|---|
| 90 - 100 % | 450 - 500 MW | 2,291 | 1,101,792 | 10,725 |
| 80 - 89 % | 400 - 449 MW | 883 | 376,195 | 10,815 |
| 70 - 79% | 350 - 399 MW | 595 | 224,049 | 10,978 |
| 60 - 69% | 300 - 349 MW | 566 | 186,592 | 11,197 |
| 50 - 59% | 250 - 299 MW | 216 | 59,193 | 11,400 |
| <50% | Less than 250 MW | 105 | 24,945 | 11,783 |
| | | **Annual Averages** | **85% AOCF** | **10,850** |

As it was expected for most coal-fired units, Merom Unit 1 operates most efficiently at full load and steadily increases NURH as load decreases.

**Figure 5: Merom Unit 2 – Weighted Average Heat Rate Curve**

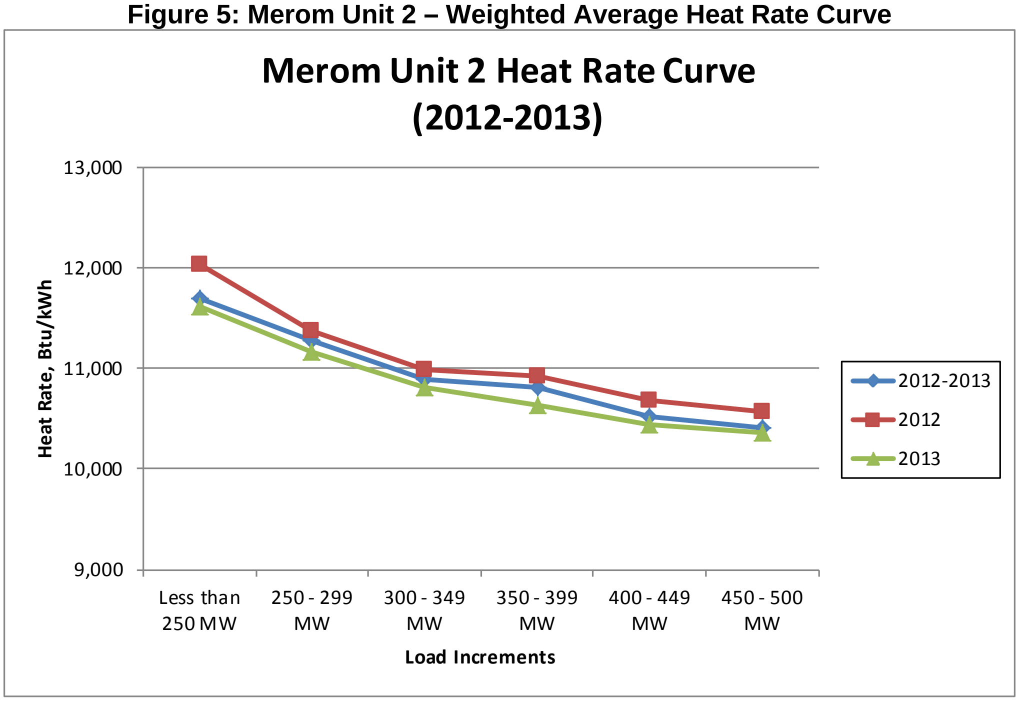


**Table 9: Merom Unit 2 - 10% Load Increments**

| Load Increment | Net Load Increment ($MW_{NET}$) | # of Operating Hours (hours) | Total Generation (MW) | Average NUHR (Btu/kWh-net) |
|---|---|---|---|---|
| **2012 Data** | | | | |
| 90 – 100% | 450 - 500 MW | 1,140 | 543,866 | 10,576 |
| 80 – 89% | 400 - 449 MW | 555 | 235,060 | 10,686 |
| 70 – 79% | 350 - 399 MW | 1,792 | 652,486 | 10,918 |
| 60 – 69% | 300 - 349 MW | 1,236 | 415,066 | 10,992 |
| 50 – 59% | 250 - 299 MW | 436 | 116,347 | 11,370 |
| <50% | Less than 250 MW | 8 | 1,874 | 12,026 |
| | | **Annual Average** | **76% AOCF** | **10,839 NUHR** |
| **2013 Data** | | | | |
| 90 – 100% | 450 - 500 MW | 3,545 | 1,691,965 | 10,354 |
| 80 – 89% | 400 - 449 MW | 1,288 | 548,764 | 10,443 |
| 70 – 79% | 350 - 399 MW | 1,185 | 442,944 | 10,640 |
| 60 – 69% | 300 - 349 MW | 1,660 | 556,336 | 10,814 |
| 50 – 59% | 250 - 299 MW | 336 | 91,827 | 11,162 |
| <50% | Less than 250 MW | 30 | 7,195 | 11,608 |
| | | **Annual Average** | **83% AOCF** | **10,508 NUHR** |

From Figures 2 and 3, it appears that Merom Unit 2 is dispatched similarly to Unit 1, though it has a slightly lower AOCF. At full load, the unit is the most efficient and steadily decreases efficiency as the load decreases as well. As AOCF increased by 7% between 2012 and 2013, the average NUHR decreased by approximately 3%. The data indicate that any additional operation at lower loads due to cycling will increase the heat rate.

### 5.2.2. San Miguel

San Miguel Station is located in Texas and has a generation capacity of approximately 425 $MW_{GROSS}$ which translates into approximately 400 $MW_{NET}$. The unit is subcritical and fires lignite fuel. Figure 6 shows that the unit is mainly base loaded, with increased cycling in the spring of 2014. The AOCFs are 96%, 95%, and 87% for 2012, 2013, and through July 2014, respectively.

**Figure 6: San Miguel - 2012-2014 Dispatch**

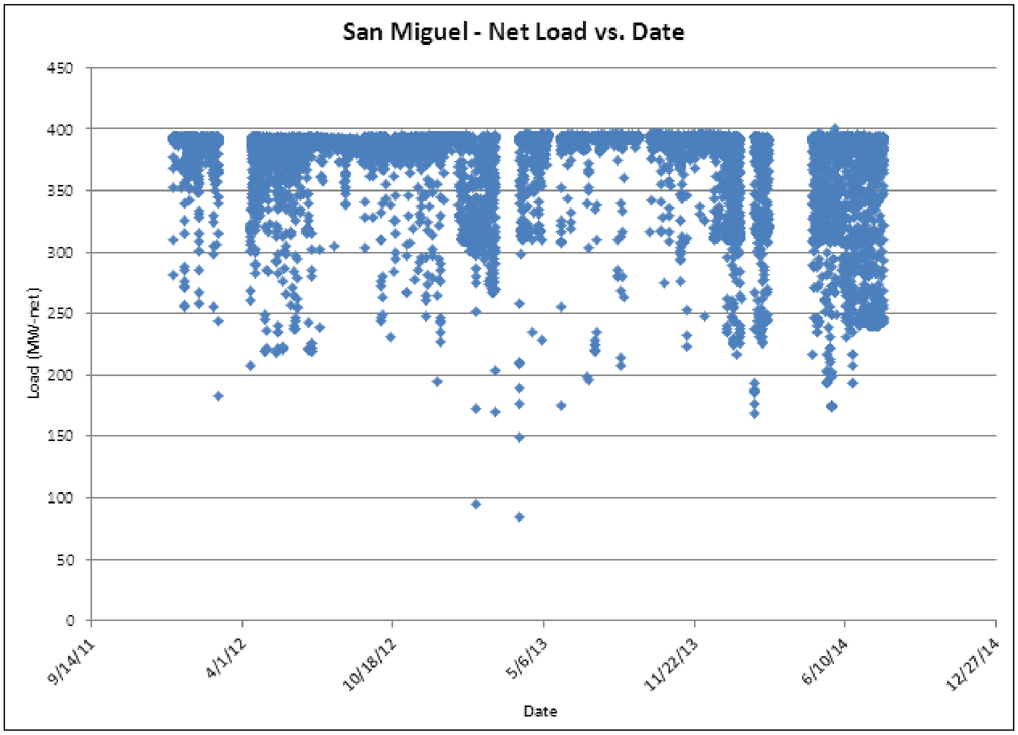



**Figure 7: San Miguel – Weighted Average Heat Rate Curve**

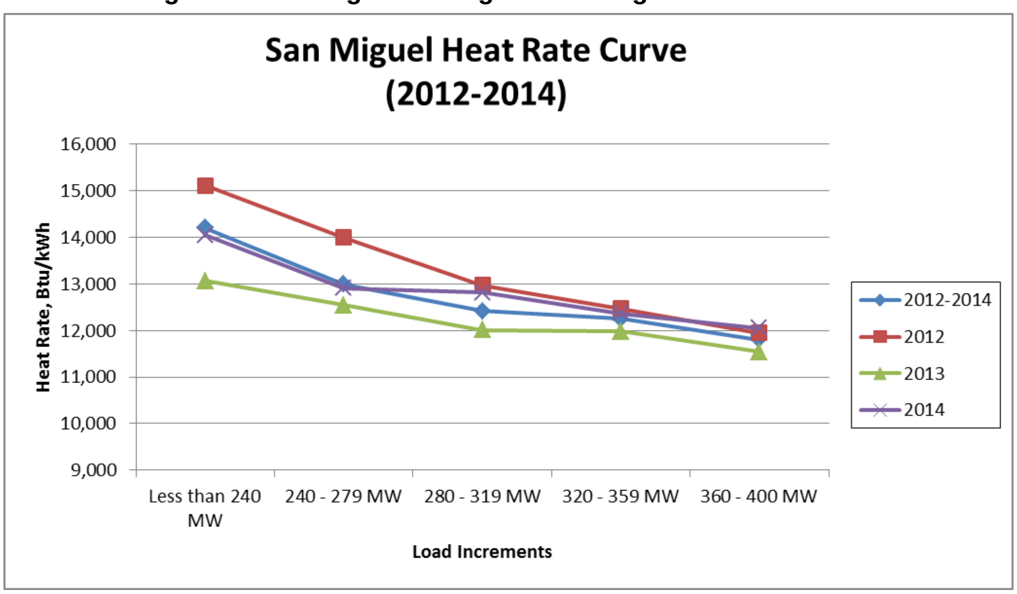


**Table 10: San Miguel – 10% Load Increments**

| Load Increment | Net Load Increment ($MW_{NET}$) | # of Operating Hours (hours) | Total Generation (MW) | Average NUHR (Btu/kWh-net) |
|---|---|---|---|---|
| **2012 Data** | | | | |
| 90 - 100 % | 360 - 400 MW | 7,063 | 2,753,871 | 11,945 |
| 80 - 89 % | 320 - 359 MW | 196 | 67,291 | 12,461 |
| 70 - 79% | 280 - 319 MW | 103 | 31,423 | 12,964 |
| 60 - 69% | 240 - 279 MW | 49 | 12,764 | 13,990 |
| < 60% | Less than 240 MW | 48 | 10,651 | 15,112 |
| | | **Annual Average** | **96% AOCF** | **11,989 NUHR** |
| **2013 Data** | | | | |
| 90 - 100 % | 360 - 400 MW | 5,784 | 2,268,360 | 11,543 |
| 80 - 89 % | 320 - 359 MW | 317 | 107,788 | 11,976 |
| 70 - 79% | 280 - 319 MW | 692 | 214,603 | 12,004 |
| 60 - 69% | 240 - 279 MW | 42 | 11,357 | 12,542 |
| < 60% | Less than 240 MW | 30 | 6,013 | 13,062 |
| | | **Annual Average** | **95% AOCF** | **11,606 NUHR** |
| **2014 Data (through July)** | | | | |
| 90 - 100 % | 360 - 400 MW | 1,897 | 736,817 | 12,049 |
| 80 - 89 % | 320 - 359 MW | 420 | 141,280 | 12,363 |
| 70 - 79% | 280 - 319 MW | 560 | 173,614 | 12,816 |
| 60 - 69% | 240 - 279 MW | 352 | 88,662 | 12,905 |
| < 60% | Less than 240 MW | 87 | 18,621 | 14,038 |
| | | **Annual Average** | **87% AOCF** | **12,300 NUHR** |

Being a lignite unit, it is expected that San Miguel would have a slightly higher baseline average heat rate than bituminous fired units. A comparison of the San Miguel curve in Figure 9 to the Merom data in Figures 6 and 7 proves this to be true. Similar to the Merom units, as the AOCF decreases in 2014, the annual average NUHR increases by nearly 6% from the previous year.

### 5.2.3. Holcomb Unit 1

Holcomb Station is located in Kansas and has a generation capacity of approximately 380 $MW_{GROSS}$ which translates into approximately 350 $MW_{NET}$. The unit is subcritical and fires PRB fuel. Figure 8 shows that the unit was forced to cycle often since the beginning of 2014. The AOCF through July 2014 is 65%.

**Figure 8: Holcomb Unit 1 - 2014 Dispatch**

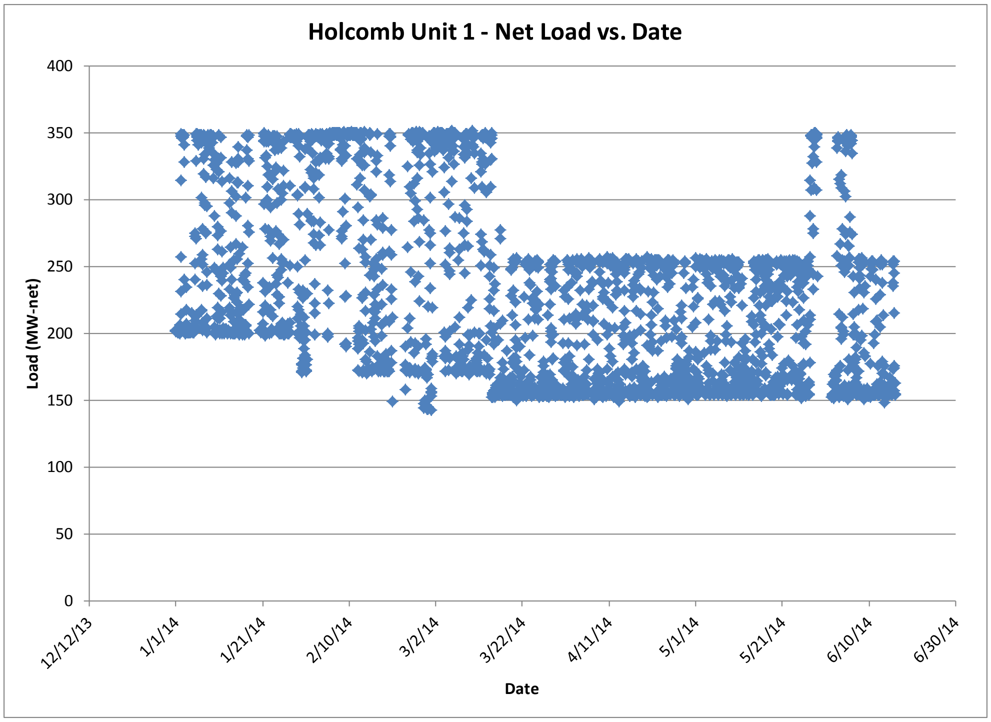


**Figure 9: Holcomb Unit 1 – Weighted Average Heat Rate Curve**

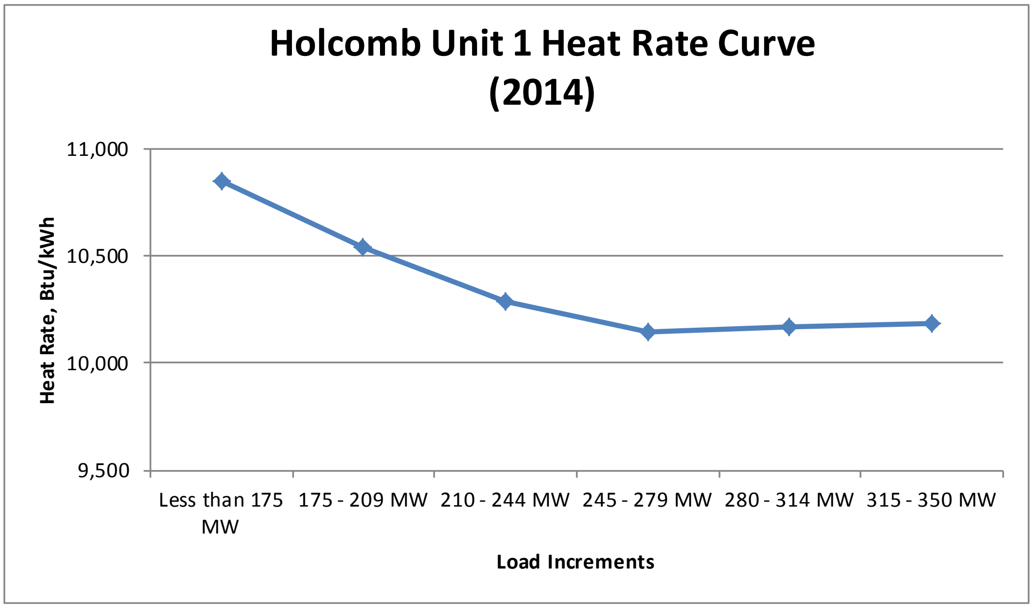



**Table 11: Holcomb Unit 1 – 10% Load Increments**

| Load Increment | Net Load Increment ($MW_{NET}$) | # of Operating Hours (hours) | Total Generation (MW) | Average NUHR (Btu/kWh-net) |
|---|---|---|---|---|
| **2014 Data (through July)** | | | | |
| 90 - 100 % | 315 - 350 MW | 771 | 265,925 | 10,186 |
| 80 - 89 % | 280 - 314 MW | 89 | 26,638 | 10,171 |
| 70 - 79% | 245 - 279 MW | 646 | 164,531 | 10,149 |
| 60 - 69% | 210 - 244 MW | 315 | 71,711 | 10,288 |
| 50 - 59% | 175 - 209 MW | 561 | 109,731 | 10,537 |
| < 50% | Less than 175 MW | 1,375 | 220,083 | 10,852 |
| | | **Annual Average** | **65% AOCF** | **10,403 NUHR** |

Similarly to Merom Unit 1, Holcomb Unit 1 operates most efficiently at high loads and NURH increases as load decreases.

### 5.2.4. RD Green Units 1 and 2

RD Green Station is comprised of two coal-fired units located in Kentucky. Each unit has a generation capacity of approximately 260 $MW_{GROSS}$. The units are subcritical and fire bituminous fuel. Both units have similar dispatch rates. Personnel from Green Station were unable to provide net generation data for this study. Therefore the following analysis is based on gross unit heat rate (GUHR) rather than net.

Figures 10 and 11 show that the units cycle very frequently between 175–260 $MW_{GROSS}$. The AOCFs for Unit 1 were approximately 85% for 2012 and 88% for 2013. The Unit 2 AOCFs were 81% and 85% for 2012 and 2013, respectively.

**Figure 10: Green Unit 1 - 2012-2013 Dispatch**

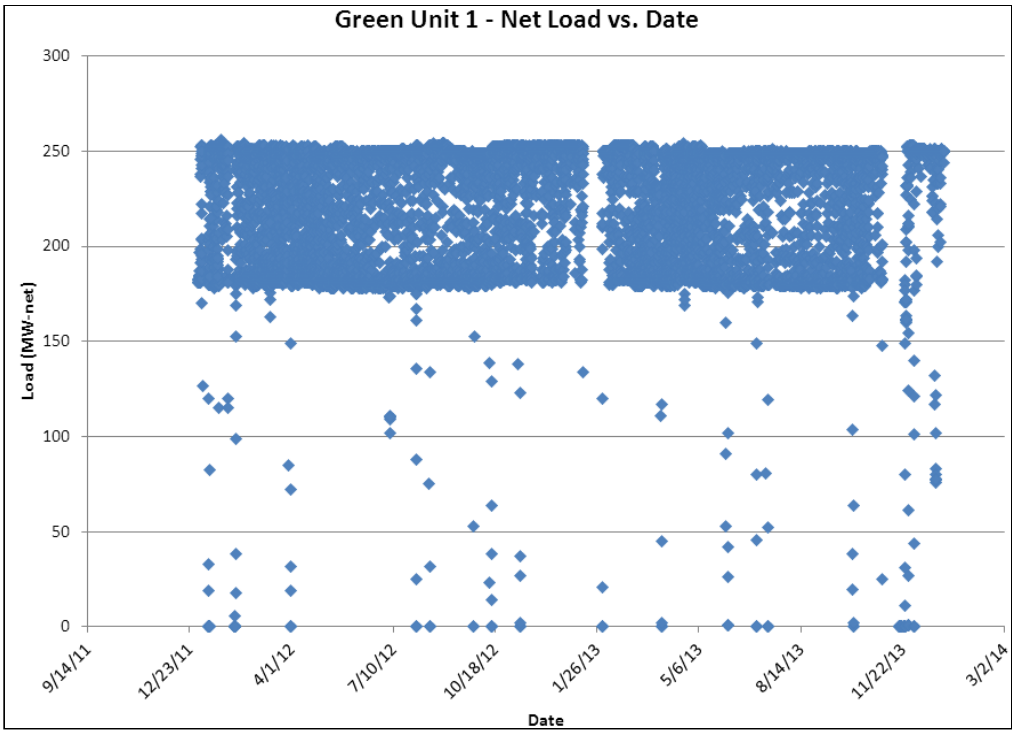


**Figure 11: Green Unit 2 - 2012-2013 Dispatch**

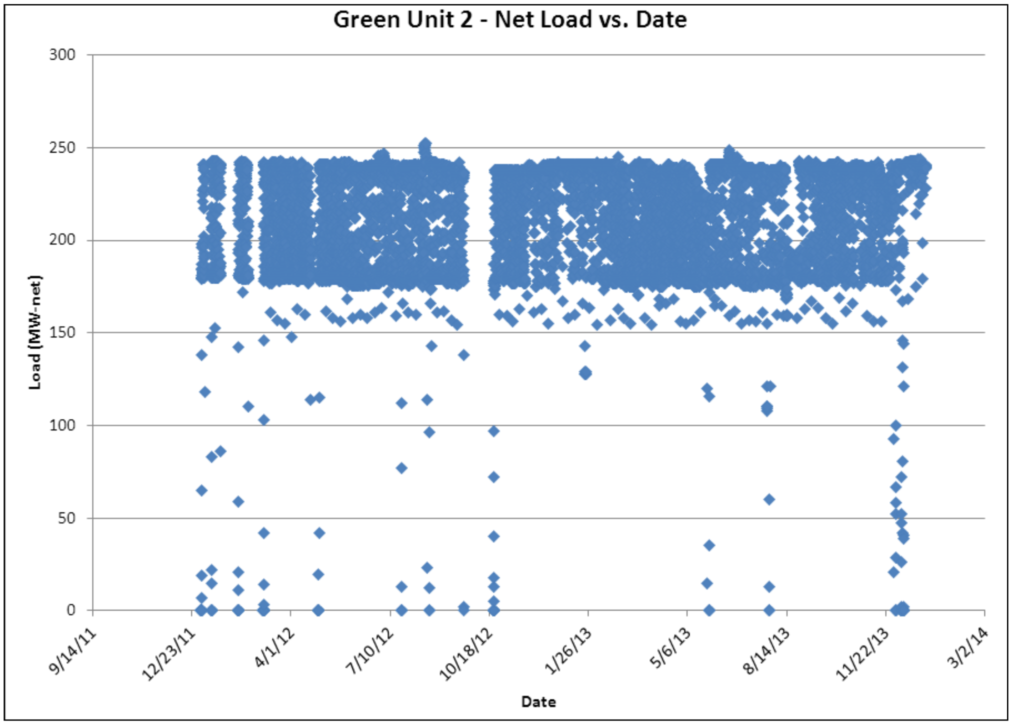



**Figure 12: Green Unit 1 - Weighted Average Heat Rate Curve**

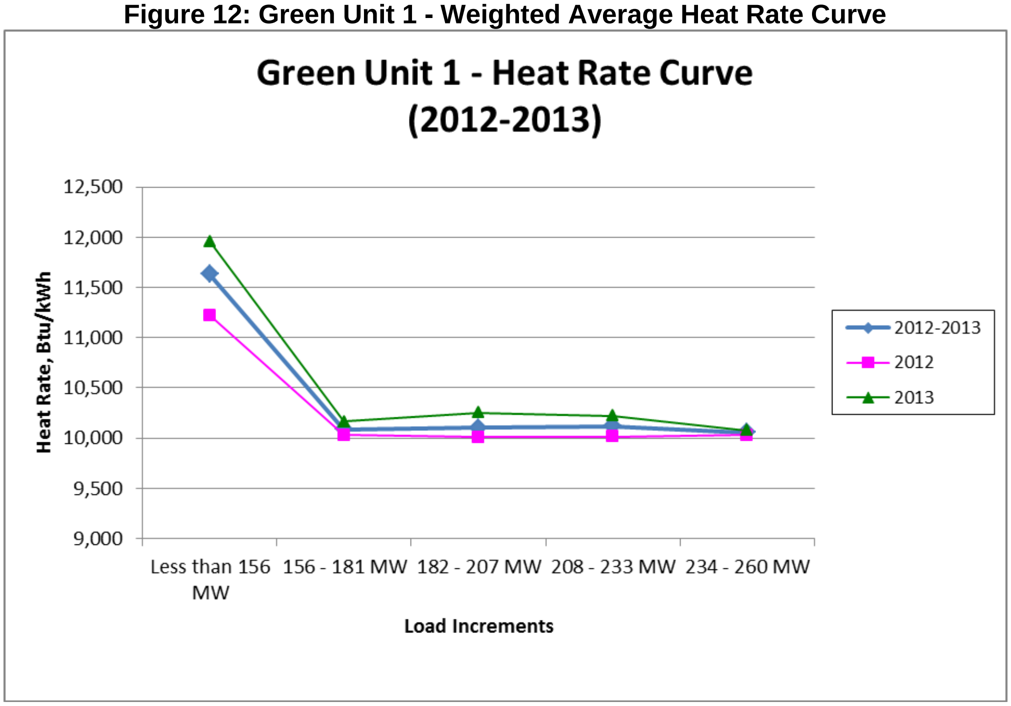


**Table 12: Green Unit 1 - 10% Load Increments**

| Load Increment | Gross Load Increment ($MW_{GROSS}$) | # of Operating Hours (hours) | Total Generation (MW) | Average GUHR (Btu/kWh-gross) |
|---|---|---|---|---|
| **2012 Data** | | | | |
| 90 – 100% | 234 - 260 MW | 4,217 | 1,051,563 | 10,029 |
| 80 – 89% | 208 - 233 MW | 627 | 138,258 | 10,012 |
| 70 – 79% | 182 - 207 MW | 1,959 | 366,675 | 10,010 |
| 60 – 69% | 156 - 181 MW | 1,167 | 210,022 | 10,028 |
| <60% | Less than 156 MW | 41 | 3,277 | 11,219 |
| | | **Annual Average** | **85% AOCF** | **10,026 GUHR** |
| **2013 Data** | | | | |
| 90 – 100% | 234 - 260 MW | 5,237 | 1,303,961 | 10,077 |
| 80 – 89% | 208 - 233 MW | 657 | 146,088 | 10,218 |
| 70 – 79% | 182 - 207 MW | 1,193 | 225,637 | 10,253 |
| 60 – 69% | 156 - 181 MW | 835 | 49,793 | 10,163 |
| <60% | Less than 156 MW | 57 | 4,104 | 11,957 |
| | | **Annual Average** | **88% AOCF** | **10,122GUHR** |

At full load, the unit is the most efficient and steadily decreases as the load decreases. As AOCF increased slightly between 2012 and 2013, the average GUHR increased by approximately 1%. It is possible that the higher heat rates experienced at all loads in 2013 as compared to 2012 were a result of being further along in the unit's maintenance cycle. If this is the case, it means that the unit will likely achieve a full load heat rate reduction when the maintenance activities commence; however, rates will likely degrade back to similar values at some point between maintenance cycles.

Figure 13: Green Unit 2 – Weighted Average Heat Rate Curve

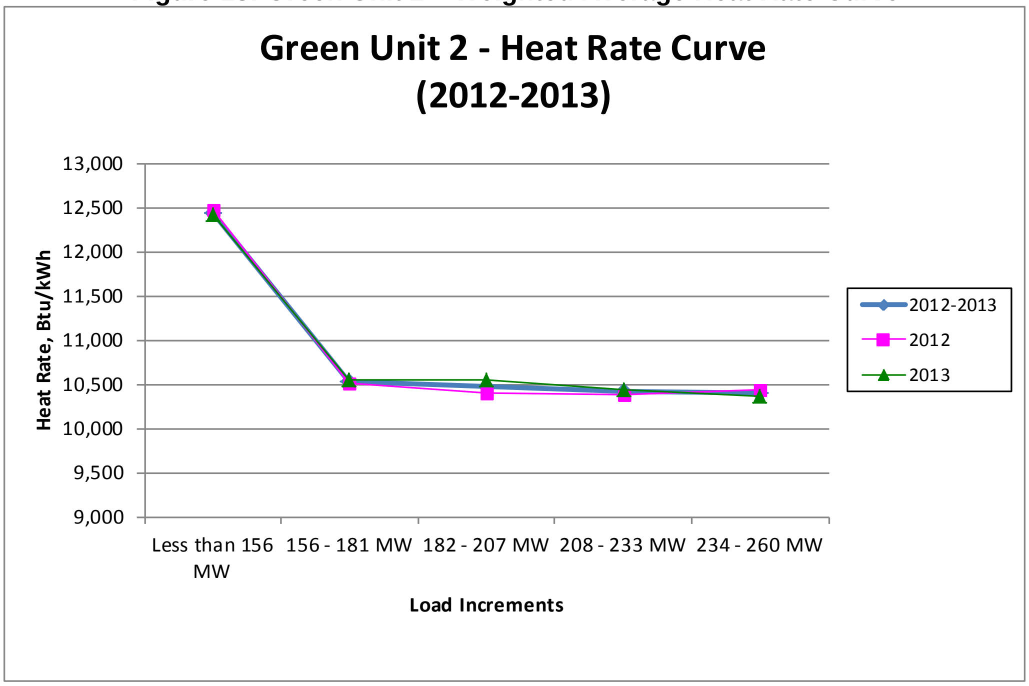


**Table 13: Green Unit 2 - 10% Load Increments**

| Load Increment | Gross Load Increment ($MW_{GROSS}$) | # of Operating Hours (hours) | Total Generation (MW) | Average GUHR (Btu/kWh-gross) |
|---|---|---|---|---|
| **2012 Data** | | | | |
| 90 – 100% | 234 - 260 MW | 3,027 | 723,805 | 10,434 |
| 80 – 89% | 208 - 233 MW | 776 | 172,220 | 10,380 |
| 70 – 79% | 182 - 207 MW | 1,150 | 219,785 | 10,399 |
| 60 – 69% | 156 - 181 MW | 1,837 | 328,185 | 10,508 |
| <60% | Less than 156 MW | 45 | 3,383 | 12,465 |
| | | **Annual Average** | **81% AOCF** | **10,444 GUHR** |
| **2013 Data** | | | | |
| 90 – 100% | 234 - 260 MW | 4,821 | 1,154,942 | 10,364 |
| 80 – 89% | 208 - 233 MW | 1,186 | 264,766 | 10,438 |
| 70 – 79% | 182 - 207 MW | 1,141 | 218,190 | 10,538 |
| 60 – 69% | 156 - 181 MW | 1,347 | 239,473 | 10,542 |
| <60% | Less than 156 MW | 50 | 4,748 | 12,413 |
| | | **Annual Average** | **85% AOCF** | **10,423GUHR** |

From Figures 12 and 13, it appears that Green Unit 2 operates similarly to Unit 1, though it has slightly lower AOCFs. At full load, the unit is the most efficient and steadily decreases efficiency as the load decreases as well. As AOCF increased slightly between 2012 and 2013, the average GUHR negligibly decreased.

### 5.2.5. Apache Unit 3

Apache Station is located in Arizona and has a generation capacity of approximately 200 $MW_{GROSS}$ which translates into approximately 180 $MW_{NET}$. The unit is subcritical and fires PRB fuel. From the following figure, it can be noticed that the unit cycles very frequently between 50–180 $MW_{NET}$. The AOCFs are 58% and 80% for 2012 and 2013, respectively.

**Figure 14: Apache Unit 3 - 2012-2013 Dispatch**

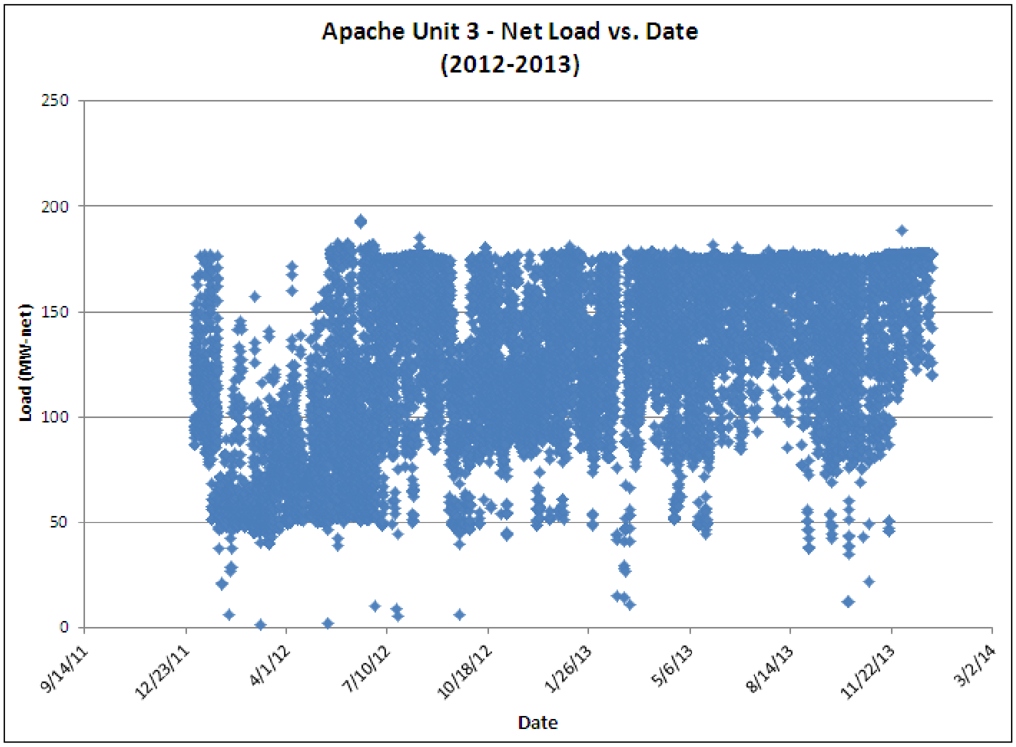



**Figure 15: Apache Unit 3 - Weighted Average Heat Rate Curve**

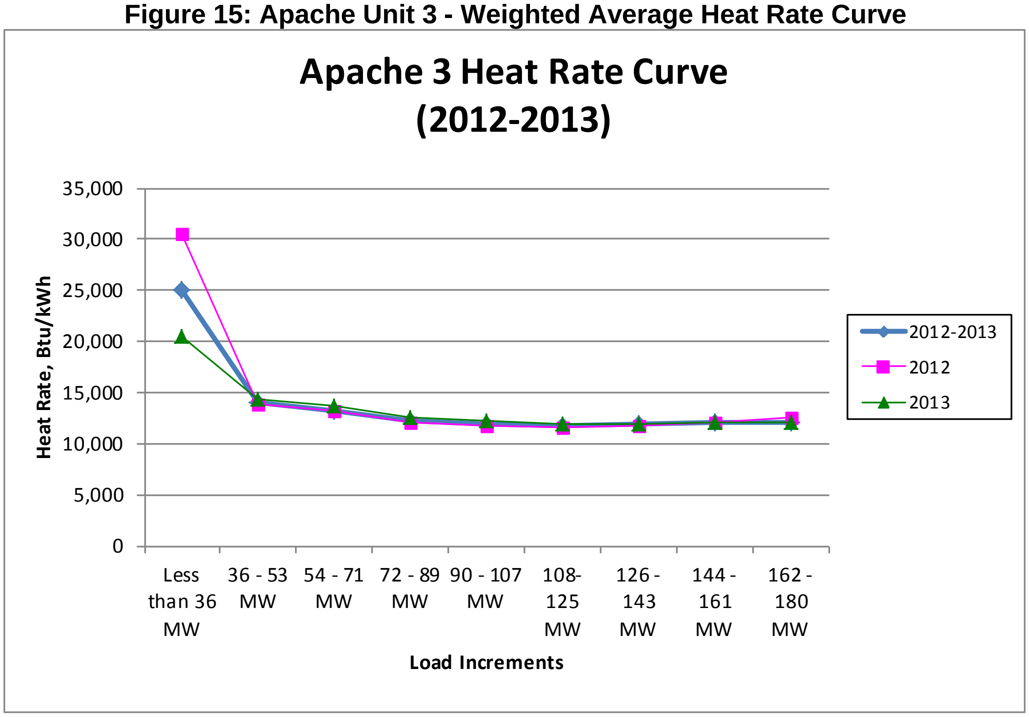


**Table 14: Apache Unit 3 – 2012 & 2013 10% Load Increments**

| Load Increment | Net Load Increment ($MW_{NET}$) | # of Operating Hours (hours) | Total Generation (MW) | Average NUHR (Btu/kWh-net) |
|---|---|---|---|---|
| **2012 Data** | | | | |
| 90 – 100% | 180 - 200 MW | 1,115 | 193,036 | 12,592 |
| 80 – 89% | 160 - 179 MW | 693 | 105,613 | 12,017 |
| 70 – 79% | 140 - 159 MW | 780 | 104,383 | 11,717 |
| 60 – 69% | 120 - 139 MW | 1,358 | 158,906 | 11,634 |
| 50 – 59% | 100 - 119 MW | 1,342 | 131,522 | 11,716 |
| 40 – 49% | 80 - 99 MW | 1,046 | 84,744 | 12,033 |
| 30 – 39% | 60 - 79 MW | 1,455 | 89,549 | 13,206 |
| 20 – 29% | 40 - 59 MW | 908 | 45,790 | 13,896 |
| <20% | Less than 40 MW | 12 | 168 | 30,469 |
| | | **Annual Average** | **58% AOCF** | **12,211 NUHR** |
| **2013 Data** | | | | |
| 90 – 100% | 180 - 200 MW | 3,162 | 728,208 | 12,020 |
| 80 – 89% | 160 - 179 MW | 2,169 | 174,003 | 12,018 |
| 70 – 79% | 140 - 159 MW | 1,156 | 155,690 | 11,964 |
| 60 – 69% | 120 - 139 MW | 871 | 102,428 | 11,946 |
| 50 – 59% | 100 - 119 MW | 601 | 59,175 | 12,229 |
| 40 – 49% | 80 - 99 MW | 328 | 27,465 | 12,567 |
| 30 – 39% | 60 - 79 MW | 37 | 2,214 | 13,650 |
| 20 – 29% | 40 - 59 MW | 104 | 5,006 | 14,381 |
| <20% | Less than 40 MW | 10 | 207 | 20,547 |
| | | **Annual Average** | **83% AOCF** | **12,043 NUHR** |

As can be seen from Table 12, the average NUHR for a year when the unit operated at a higher AOCF (2013) is lower by approximately 1.4%.

### 5.2.6. Morrow Units 1 & 2

Morrow Station is located in Mississippi and has a generation capacity of 200 $MW_{GROSS}$. The unit is subcritical and fires bituminous fuel. Morrow Station personnel had already created a curve fit of heat rate vs. load that is was product of over two years of historical data. Since only heat rate curves were provided by the station, rather than hourly data, the AOCF and load dispatch are not analyzed. The following figures show the heat rate curves for Morrow 1 and 2, respectively, and include a line on the graph that distinguishes when the final (third) mill is brought online. While NUHR is most applicable to this analysis, it is likely that this curve represents gross heat rate. This is inferred due to the max load being equivalent to the generator nameplate rating listed in the EIA database, as well as the fact that the unit heat rate is as low as 9,750 Btu/kWh, which is very low for a net heat rate. However, this has not been confirmed.

**Figure 16: Morrow Unit 1 - Heat Rate Curve**

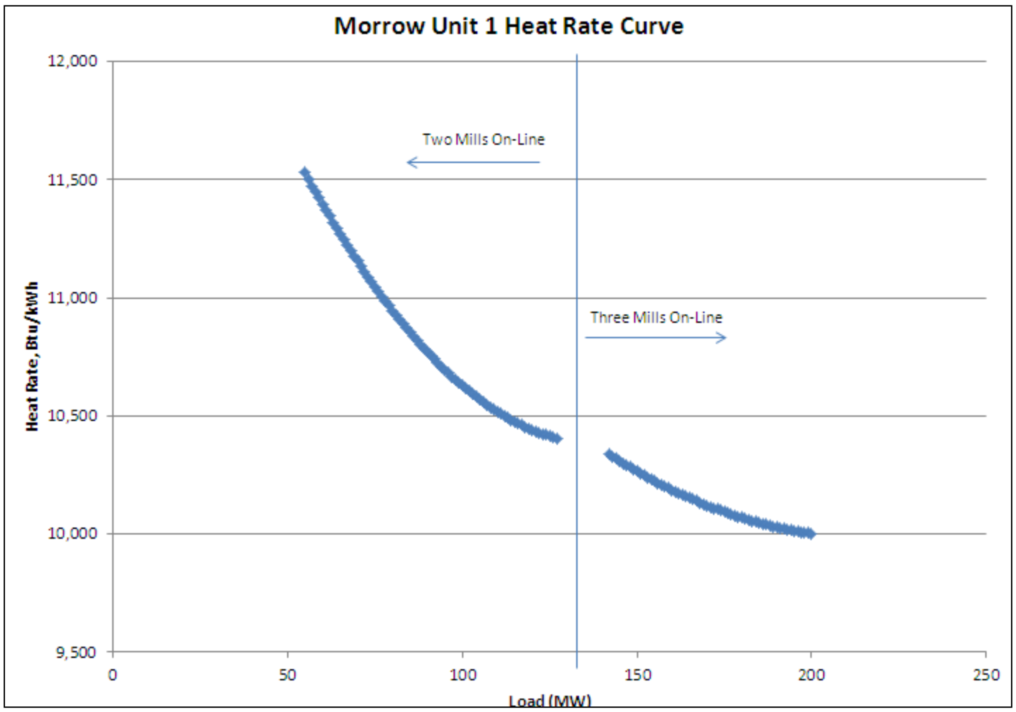
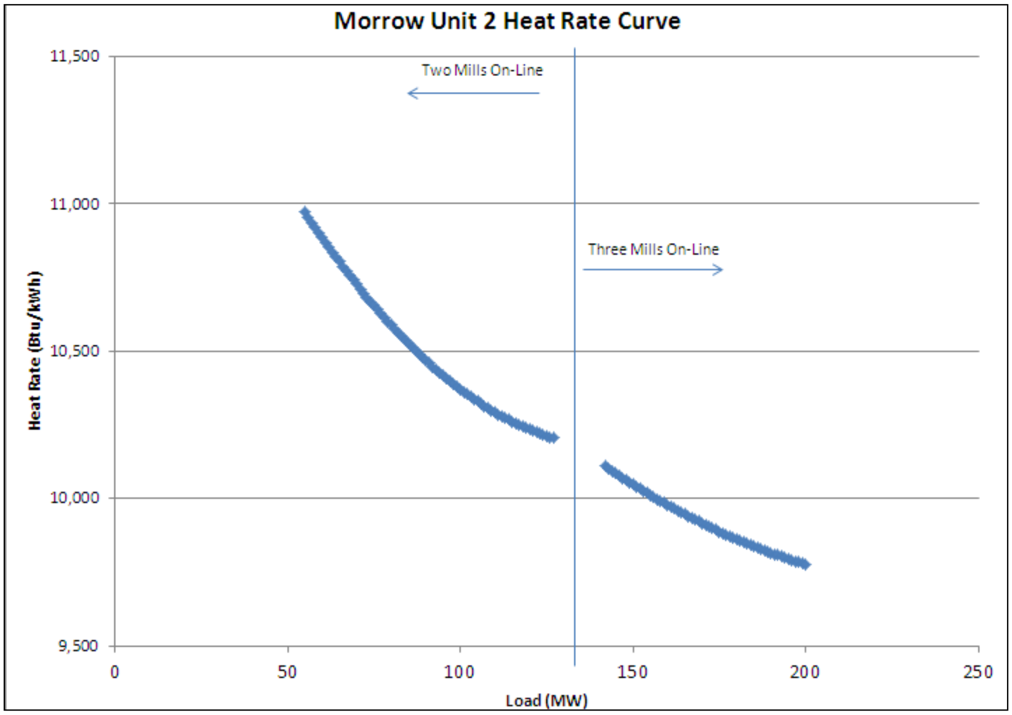
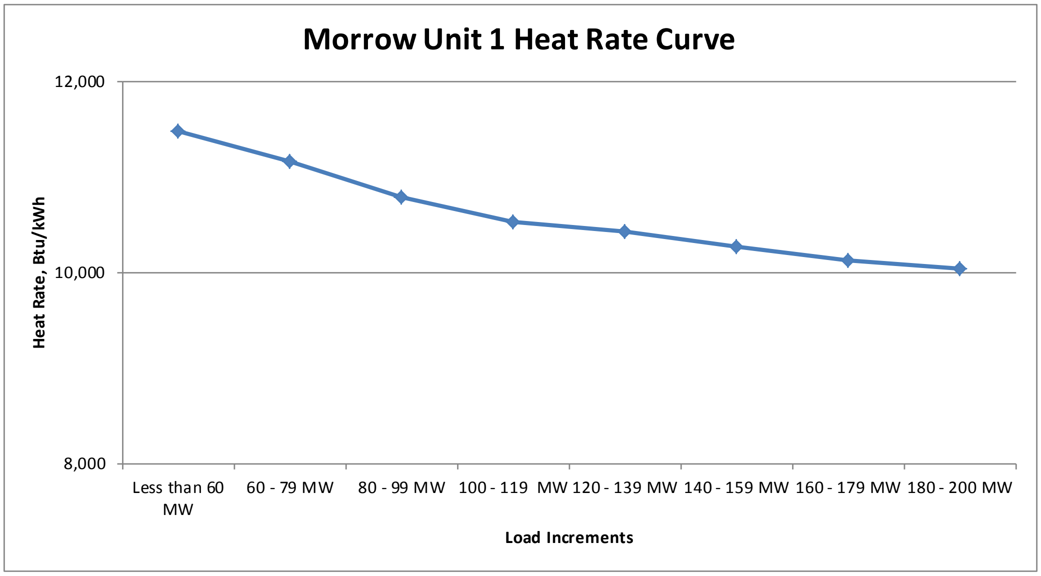


**Figure 17: Morrow Unit 2 - Heat Rate Curve**




Figures 16 and 17 show very steady heat rate improvement as unit load increases, which follows the trends of other units analyzed. Using the trend line created from the previous graph for Unit 1, a similar curve to that in the other analyses can be created.

**Figure 18: Morrow Unit 1 – Incremental Heat Rate Curve**




### *5.3. Effect of Increased Dispatch at Lower Load*

Block 2 of the EPA's $CO_2$ reduction strategy, stated in the draft regulation, requires increasing generation dispatch to natural gas combined cycle (NGCC) units, due to the lower $CO_2$ emission rate that is associated with natural gas.[10] By increasing dispatch to NGCC units, many coal-fired units may be forced to operate at lower loads consistently. Additionally, Block 3 of the EPA's strategy suggests dispatching more generation to renewable resources like wind and solar. Depending on the availability of these resources on a regular basis in each state, coal units might cycle more frequently, resulting in units operating at loads below their peak efficiency rates. 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 NUHR from their baseline average. Section 5.2 looked at various units to gain an understanding as to how cycling or low unit dispatch affects the annual average heat rate of a unit. From these curve trends, it can be concluded that operating most often greater than 90% of net load capacity will provide the lowest annual weighted average heat rate. By requiring units to consistently operate at low loads, the

[10]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.

low average operating capacity factors will drive the annual heat rate up. The following example uses trends and data developed in Section 5.2 from Merom Unit 1.

**Table 15: Example Heat Rate Impact with Increased Cycling (Merom Unit 1)**

| | Units | Baseline Load Profile | Reduced Load Profile |
|---|---|---|---|
| Annual Operating Capacity Factor | % | 85 | 65 |
| Average Annual Net Plant Heat Rate | Btu/kWh-net | 10,850 | 11,179 |
| Heat Rate Increase | % | -- | 3 |

Block 1 of the EPA strategy outlines 6% heat rate reduction from their historical baseline (2012). By reducing dispatch rates of historically high capacity units, their future average heat rate would increase if they were to operate more frequently at lower loads in the future (based on the same total hours of operation). 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.

# 6. HEAT RATE DEGRADATION

As previously discussed, the EPA proposed state $CO_2$ emission rate goals, part of which assume that, on average, the existing coal-fired units can decrease heat rate by 6% as part of Block 1. Pursuant to the proposal, each state will be required to achieve their interim goals over a 10-year average between 2020 and 2029, 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 report, it will be much more difficult to sustain that percentage improvement over a long term timeframe, because each piece of major equipment degrades with continued operation. This normal degradation in performance increases plant heat rate. To account for this degradation in performance/efficiency improvement, units would need to design for a higher heat rate reduction that will average out to be consistent with the state's requirements. Therefore, it is critical to account for normal degradation when developing a long range plan.

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; 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. Other BP options like implementing VFDs on ID and FD fans are not expected to degrade significantly over time; therefore, the immediate heat rate reduction is often very close to the sustainable heat rate improvement.

Many other HRI methods, such as turbine upgrade (not to be confused with overhaul maintenance), may provide a significant reduction in heat rate immediately after implementation, but are more susceptible to degradation because, over time, pieces warp and erode, providing less and less heat rate reduction. A rigorous maintenance schedule including a major overhaul (replace packing and seals) every 7-10 years will help maintain sustainable turbine efficiency. However, it will never be able to achieve the same efficiency as when it was initially installed. Over the course of multiple years, the equipment will provide less and less annual heat rate improvement. Therefore, performance degradation should be accounted for when considering certain HRI technologies, such as turbine upgrades or air heater seal replacements, as part of a long-term sustainable heat rate improvement strategy. 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.

# 7. CASE STUDIES

The purpose of this part of the engineering study is to conduct a heat rate improvement audit for a total of five units that are located at "Station A" and "Station B" for members of "The National Rural Electric Cooperative Association" (NRECA). As noted in Section 2, this audit was conducted in response to the EPA's claim that 6% heat rate improvement is feasible for all coal units and to demonstrate that unit-by-unit audits may not support the EPA's claim.

## *7.1. Scope*

The following technical methods were identified in the 2009 Report for efficiency improvement and heat rate reductions:

- Boiler island
  - Coal transport, conveying, and grinding
  - Boiler operation/overhaul with new heat transfer surface
  - Neural network (NN) control systems
  - Intelligent sootblowers (ISB) systems
  - Air heaters
- Turbine island
  - Turbine
  - Feedwater heaters
  - Condenser
  - Turbine drive/motor-driven feed pumps
- Flue gas system
  - Forced draft (FD) and induced draft (ID) fan improvement
  - Variable Frequency Drives (VFDs)
- Air pollution control equipment
  - Flue gas desulfurization (FGD) system
  - Particulate system
  - Selective catalytic reduction (SCR) system
- Water treatment system
  - Boiler water treatment
  - Cooling tower

S&L has evaluated each technical method to determine whether they are technically applicable at each of the units as a means of reducing heat rate. For the methods that are determined to be technically applicable, S&L estimated the reduction in unit heat rate specific to those units. This report documents the following:

- Identification of previous heat rate improvement projects and results.
- Identification of technical methods and/or operating practices that could potentially improve unit heat rates at each of the units
- Estimated reduction in unit heat rate resulting from implementation of the technical methods or operating practices determined to be technically applicable at each of the units
- Evaluate commercially available and current industry-wide demonstrated applications of the technical alternative or operating practices
- Impacts on balance of plant at each of the units
- Identify penalties associated with regulations such as BART, MATS, etc.

It should be noted that the scope of this report does not include any detailed design work. Should any of the units implement any of the technologies identified as potentially improving heat rate at either station, detailed design work may reveal limitations in either the applicability of the technology or limitations on the achievable heat rate reduction.

### *7.2. Assumptions*

The key assumptions included in S&L's analysis are summarized below:

- For technologies that have already been implemented at the units, this report assumes that data available for net plant load and heat input are accurate enough to report relative changes to heat rate before and after a project was implemented. Data ranges analyzed were selected to isolate contributions of specific improvements to the extent possible.

- For technologies that cannot be compared to plant data, the change in auxiliary power was used to estimate the net heat rate change. Since EPA's proposed rule uses net heat rate and net generation for its analysis, the change in auxiliary power is compared to the net load rating of the units.

- The heat rate improvements were evaluated based on base-loaded operation. Increased cycling and long term operation at lower loads will result in higher heat rates because units are designed to optimize efficiency at full load.

- The net unit heat rate improvements estimated in the case studies are estimated at full load operating conditions; therefore, these values should not be used to determine a plant specific $CO_2$ emission rate on an annual average basis.

- Unless otherwise noted, normal equipment degradation has not been accounted for in this evaluation; therefore, estimates of heat rate improvements are generally based on "like new" conditions just after initial installation.

### *7.3. Station A*

Two units at Station A were audited as part of this study. Units A1 and A2 are supercritical pulverized coal units that are between 500-700$MW_{NET}$. Each unit is equipped with electrostatic precipitators (ESPs), selective catalytic reduction (SCR) systems, wet flue gas desulfurization (WFGD) systems, and dry sorbent injection (DSI).

This section of the report summarizes heat rate improvement strategies identified in the 2009 Report that are applicable on each unit and estimates the approximate reduction, both on a past and future basis for the units at Station A. Previous improvements to units that have resulted in heat rate reduction will be quantified to determine an overall achievement profile to-date. After considering improvements that have already been completed and the technical feasibility of the remaining strategies, this section will provide an overall profile of past and future unit heat rate reductions.

For heat rate improvements that have already taken place, the section below identifies what year the technologies were installed, what heat rate changes were observed, and if additional improvements would achieve further reductions in heat rate.

#### 7.3.1. Boiler Island

This section of the report discusses equipment within the Unit A1 and A2 boiler islands that offer potential improvements in plant heat rate:

- Material handling
- Boiler operation/overhaul with new heat transfer surface
- Neural network system and intelligent sootblowers
- Air pre-heaters

#### 7.3.1.1. Material Handling

Material handling systems include coal, bottom ash, and fly ash handling. The bottom ash (BA) and flyash (FA) systems at Station A are wet handling systems and have not been converted to dry handling. Unit A2 alone has 23 pumps in the BA/FA handling systems. Although all pumps are not operating at once, there is a significant amount of auxiliary (aux) power required to operate the ash handling systems.

With respect to ash handling systems, heat rate improvements can often be realized by converting wet handling systems to dry handling systems by eliminating equipment and auxiliary power loads associated with the transport of water. Both units at Station A are equipped with wet FA and BA handling systems, and therefore could benefit from conversion to dry handling systems. Flyash handling conversion would reduce the total amount of pumps required, but would increase the vacuum system power requirements. Conversion to drag chain conveyance system for BA handling could reduce pump power requirement; however, site constraints must be considered when evaluating the feasibility of this improvement from a technical and economic standpoint. Typical wet-to-dry conversions cost in the range of $20-30/kW; however, due to these site constraints, it may be determined that the constraints would make this economically infeasible for heat rate improvement. Additionally, $CO_2$ emissions due to truck hauling the ash are not considered in this report.

Unit A1 is currently in the process of converting a second coal mill to a Fat Boy tire systems, which will increase the capacity and fineness of the milled coal product. The increase in mill capacity will provide more reliability and maintainability and will allow full load generation if one mill is down for routine maintenance. While the increased capacity could potentially allow the unit to operate one less mill for the same design throughput, the unit maintains all mills in operation to increase reliability. Therefore, no heat rate improvement is possible.

In recent years, Unit A2 installed soft-starts on their coal conveyor motors. The soft starts provided slight aux power improvement, but due to intermittent fuel loading, no heat rate improvement was seen. The unit is designed with a $6^{th}$ “spare” mill, but they are often forced to run on all 6 mills due to pulverizer performance.

#### 7.3.1.2. Boiler Operation/Overhaul with New Heat Transfer Surface

Adding heat transfer area to boiler surfaces is a possible methodology for reducing plant heat rate. A portion of the reheat surfaces were replaced in 2010 on Unit A1 to balance temperatures. During the installation of the SCR on Unit A2, the economizer surface area was split in half; half remained in place and the other half was relocated downstream of the SCR. The split of surface area was completed to increase flue gas temperature at the SCR inlets, while maintaining overall steam temperatures at low load operation. Due to the same heat transfer surface area being maintained, the improvements did not have an impact on the unit's heat rate, but the split economizer configuration prevented a heat rate penalty that would have been incurred by pegging the top heaters from a higher pressure alternate steam source at low loads. In addition, both units were re-rated after the installation of the FGDs on each unit between 2005-2012. The FGD project on Unit A1 also included conversion to a balanced draft system.

Adding surface to improve the steam temperatures beyond the original design values would require a major evaluation of all affected pressure parts and typically is not economical. Because no improvements to surface area were included, the replacement of these surfaces allows the units to maintain heat rate, or 0% reduction as compared to the original design. No further improvements to the superheater or reheater tubes can be made to reduce the heat rate.

#### 7.3.1.3. Neural Network and Intelligent Sootblower System

Computer models, known as neural networks (NNs) simulate the power plants at various static and dynamic loads, with the predicted performance results correlated to several real-time process measurements. Neural network control systems can be used to optimize emissions such as $NO_X$ and CO, as well as help optimize boiler efficiency.

The use of intelligent soot blower (ISB) systems for improving system efficiency also enhances the performance of the furnace and longevity of the tubing material, while minimizing cycling effects to the steam turbine. The ISB system functions by monitoring both furnace exhaust gas temperatures and steam temperatures to identify affected areas that require soot blowing.

No unit at Station A has NN installed. The utility that operates the units at Station A has previous experience with NN among their fleet, but has not experienced the advertised boiler operation benefits associated with the switch. Presently, rather than installing NN on additional units among its fleet, the utility has a burner/boiler management team that travels around their fleet to optimize and maintain the units. This team focuses on optimizing CO emissions, rather than NOx emissions, due mainly to the fact that the units are equipped with

SCRs for NOx reduction. The frequent tuning of the combustion system to optimize CO and fuel to air ratio also results in reduced unburned carbon, lower excess air, lower heat rate, and mitigates excessive slagging.

When the FGDs were installed, the Station also improved their controls to a DCS system. This allows for the implementation of NN in the future to automate a portion of the work performed by the "tuning team", if necessary. However, since the operating utility regularly has a burner management team optimize the boiler operation, it is not expected that NN would provide any further heat rate benefit.

The units at Station A are also not equipped with ISB systems. Unit A1 is currently equipped with water cannons and sootblowers in their boiler; however, there is no intelligent portion to either. The sootblowers are operated on a continuous cycle due to the heavy slagging/fouling that is experienced. Unit A2 is also equipped with sootblowers and water cannons. Six Diamond Power sootblowers were added during the FGD installation. The water cannons that are installed have an integrated intelligent operation option, but they do not operate in the intelligent mode, due to the heavy slagging that is experienced. Therefore, the addition of intelligent cleaning systems resulted in no heat rate improvement on Unit A2.

The current non-intelligent and intelligent sootblowing systems at Station A are required to operate on a consistent frequency to keep the back end tubes from fouling/slagging too much. Because of this, no additional benefit is predicted if the units were to install and regularly operate the intelligence feature.

#### 7.3.1.4. Air Pre-Heaters

Air pre-heaters are an important component of maintaining efficiency at a power plant. Such systems provide heat recovery to the unit by cooling the flue gas counter-currently with incoming pre-combustion air. Cooling of the flue gas transfers contributes to increased efficiency by recovering heat that raises combustion air temperatures and minimizes moisture in the coal prior to its combustion. With respect to air pre-heaters' contributions to plant heat rate, two possible methods to improve their performance are as follows:

- Minimizing air pre-heater leakages from the air-side to the flue-gas side. High air pre-heater leakage raises auxiliary power requirements due to processing higher volumes of gas in downstream equipment, such as ID fans, and upstream equipment, such as FD fans.
- Lowering air pre-heater outlet temperatures by controlling sulfuric acid dew point with alkali injection, allows for recovery of additional heat into the combustion air with added heat transfer surface.

*7.3.1.4.1. Minimizing Air Pre-Heater Leakage*

Unit A1 is equipped with Ljungström style air pre-heaters (APH) with duplex seals. The current leakage rate is approximately 5-8%, which is very close to design values. The operators inspect the APHs every 18 months and repair any problem areas along with replacing the seals when needed. During every outage, the air heaters are washed to remove any particle pluggage.

The Unit A1 air pre-heater currently adds only a few Btu/kWh to the design heat rate. It consistently achieves design rates after the seals are replaced and other repairs are conducted every 18 months. With the best maintenance practices conducted on a regular basis, it is not expected that any further improvements would be possible to reduce unit heat rate without excessive capital or maintenance cost expenditure.

Unit A2 is equipped with Rothemühle style air heaters. This type of APH, at the time, was designed to have a leakage rate of around 10%; however, Unit A2 was never able to achieve this rate and generally operated close to 40-50% in-leakage at the end of a three-year cycle. After APH rebuilds, the unit would only achieve approximately 20% in-leakage. Since 2012, the air heaters have been improved to include a duplex seal design, which results in lower in-leakage levels. Maximum in-leakage rates are approximately 30% and are as low as 10% immediately after rebuild. Similarly to Unit A1, the APHs on Unit A2 are inspected and repaired, to the best of the operators' ability, every 18 months. Rebuilds only happen during a long maintenance outage that occurs every three years.

To estimate the heat rate improvement achieved on Unit A2 since the incorporation of the duplex air seals, S&L estimated the aux power consumption prior to and after the duplex seal improvement. S&L calculated the change in flue gas volume from the maximum air in-leakage reported by station personnel down to the minimum in-leakage reported just after an air heater rebuild, prior to and after the improvement. The decrease in flue gas volume reduces the FD and ID fan auxiliary power consumption rates and improves the unit heat rate based on a three-year average basis. Table 2-1 compares the estimated flue gas volume, auxiliary power consumption, and heat rate due to the APH in-leakage.

**Table 16: Unit A2 Average Change due to Reduction in APH In-Leakage**

| | **Unit A2 - Reduction from 32.5% average APH in-leakage to 20% with duplex seals** |
|---|---|
| Unit A2 Flue Gas Volume at ID Fan Inlet | 9.4% |
| Unit A2 ID Fan Δ Auxiliary Power Consumption | 954 kW |
| Unit A2 Flue Gas Volume at FD Fan Inlet | 10.1% |
| Unit A2 FD Fan Δ Auxiliary Power Consumption | 2,397 kW |
| Total Unit Heat Rate Change from FD and ID Fans | 0.54% |

*7.3.1.4.2. Lower Air Pre-Heater Outlet Temperature by Controlling Acid Dew Point*

The air heater outlet temperature typically is controlled at 20-30°F above the sulfuric acid dew point to minimize corrosion of cold-end baskets. To enable lower air heater outlet temperatures, dry sorbent injection (DSI) can be installed in order to remove $SO_3$ and lower the acid dew point temperature. This technology is generally applied to medium- to high- sulfur fuel applications. The units at Station A used to fire a low-sulfur PRB blend; however, during the integration of the WFGD systems, the design incorporated a large range of medium- to high- sulfur fuels. Because of this, both units are equipped with dry sorbent injection for sulfuric acid mist (SAM) reduction prior to the FGD.

Prior to 2005, some of the air heater baskets were removed from Unit A2, due to unit performance issues. They were later reinstalled to lower the APH outlet temperature and are now back to design capacity. Unit A1 uses APH steam coils and Unit A2 uses glycol heaters to get the air side temperatures back up to design. The steam coils and the glycol heater were replaced in kind during the FGD project. Air heater baskets were also removed in Unit A2 prior to 2005 due to the high oxidation across the SCR. The elimination of the baskets helped increase the outlet flue gas temperature to above the acid dew point when high $SO_2$ and $SO_3$ concentrations were present. The SCR catalyst was eventually replaced with low oxidation catalyst that limits the amount of $SO_2$ to $SO_3$ oxidation that occurs over each catalyst layer. Most of the baskets were eventually reinstalled before 2012, due to having insufficient heat transfer after the economizer surface was split before 2005; the unit is now close to original design temperatures.

At the high sulfuric acid dew point associated with the fuel fired, air heater outlet temperatures are typically controlled to stay above 305°F. Operators have a dew point curve that they use for guidance to optimize boiler performance, while maintaining sufficient margin above the dew point. There is also a cap on air heater outlet flue gas temperature due to the injection of Trona downstream of the air heater. Temperatures above 350°F could result in the formation of sodium bisulfate which is difficult to remove from downstream surfaces as well as collecting plates, thus impacting ESP performance; therefore, the maximum air heater gas outlet temperature is set at 350°F. Sorbents can sometimes be injected upstream of the air heaters, which would eliminate the need to monitor air heater temperatures from an acid dew point standpoint; however, the DSI testing completed on the units concluded that Trona injection downstream of the air heaters was optimal for those units, due to air heater pluggage concerns. The injection of Trona upstream of the air heater would have the potential to lower acid gas concentrations through the air heater enough to lower the outlet temperature; however, it comes with the potential risk of plugging the air heater baskets due to sodium bisulfate. The reduction in flue gas temperature would increase the combustion air temperature, which increases boiler efficiency, but any pluggage/fouling in the APH has the potential to adversely affect operation. Since Trona injection on Unit A1 and A2 occurs downstream of the APH, air heater outlet temperatures cannot be reduced further. The unit cannot take advantage of reduced acid dew point temperatures unless the Trona was injected upstream of the APH. Previous testing experience by various utilities suggests that the downstream location is preferred to avoid any APH plugging as well as provided lower reagent cost for $SO_3$ reduction. Additionally, pre-APH injection was tested on the units and determined to cause detrimental pluggage after short term testing. At this time, it is not feasible to incorporate lower air heater outlet temperatures by controlling acid dew point at the APH inlet; therefore, no heat rate reduction is feasible.

### 7.3.2. Turbine Island

This section of the report discusses improvements that have been or could be made to the Station A units' equipment within the turbine island that offer potential reductions in plant heat rate:

- Turbine overhaul
- Feedwater heaters
- Condenser

#### 7.3.2.1. Turbine Overhaul

Technological advancements have improved the efficiency and longevity of steam turbines compared to the turbines that were originally installed in many older units. Advanced design tools, such as CFD have significantly enhanced turbine design capabilities that have led to increases in turbine efficiency. Additionally, the fabrication of increasingly complex geometric components has been developed to streamline design and efficiency. (Refs. 3, 4, 5, 6, 7, 8, 9, 10, 11, 12)

The turbines at Units A1 and A2 are both unique turbines. Unit A1 was built originally as a double reheat unit to enhance its efficiency above the standard single reheat design. Unit A2 was designed to be exactly half the size of the turbine sections of a large supercritical unit. Due to the complexity of a retrofit, neither unit has undergone significant turbine improvements to date. Unit A1's double reheat cycle was modified in the early 1990s to remove the stops and intercepts, but no heat rate improvement was reported. The HP/IP section was rebuilt between 2005-2012, but it did not achieve the efficiency improvement claimed by the original equipment manufacturer (OEM). Actual improvement was approximately half that predicted by the OEM, or approximately 1.5%. The LP section has not yet been improved on the unit, but the predicted future improvement is approximately 0.5%.

The Unit A2 turbine has experienced expansion issues and vibration problems. Due to leakage problems, the turbine's mid-span packing was modified to regain design performance. The station has also planned an improvement of Unit A2 LP section in 2022 with a budgetary estimate in the range of $15 million. The OEM has projected a maximum value of 2.5% heat rate improvement immediately after the project is completed. In addition, station personnel have requested budgetary quotes for the improvement of the HP and IP sections of the Unit A2 turbine. The OEM that was contacted for this project has estimated another 2.5% improvement immediately after the project at a budgetary estimate of $25 million. While the total improvement could be as high as 5% immediately after the upgrades, it is unlikely that this increase is sustainable. Due to the large difference in predicted efficiency improvement and actual efficiency improvement on Unit A1, it is assumed that, similar to Unit A1, approximately only 2% sustainable improvement is feasible.

#### 7.3.2.2. Feedwater Heaters

Feedwater heaters are used within a power plant's thermal cycle to improve overall efficiency by recovering as much heat as possible into the boiler feedwater. The number and placement of feedwater heaters are determined during the original plant design and are highly integrated with the overall performance of the steam turbine. The heat used to increase the feedwater temperature is supplied directly from the thermal cycle in the form of steam extracted at various turbine sections.

In the case of Station A, the station replaces or retubes the feedwater heaters in order to maintain overall unit performance. The Unit A1 feedwater heater was replaced in-kind in the 1990s. The Unit A2 LP heater was retubed in-kind and the HP heater is due for replacement in 2019. Regular pluggage and/or corrosion have not been a concern for either unit. Replacement of the feedwater heaters maintains unit performance with the original design. With no reduction or increase in duty, the change to heat rate is considered to be 0%. Because the units already perform best operating and maintenance practices on the feedwater heaters, no other improvements are considered to be feasible for future heat rate reductions.

#### 7.3.2.3. Condenser

By lowering the condensing temperature, the backpressure on the turbine is lowered, which increases its efficiency. A condenser degrades primarily due to fouling of the tubes, plugs in failed or thin wall tubes, and air in-leakage. Tube fouling leads to reduced heat transfer rates, plugged tubes reduce circulating water flow and heat transfer surface, and air in-leakage directly degrades heat transfer through the tubes.

The Station A maintenance program consists of routinely inspecting and cleaning the condenser during outages on a three-year cycle, with touchups after 18 months in order to maintain condenser performance. The condensers have been replaced with in-kind tubing and continue to use materials with copper. Unit A1 has looked into material replacement in the future; however, they have not experienced debilitating problems with their once-through cooling cycle. Unit A2 completed a partial re-tube in the early 2000s, with the remaining re-tubing scheduled for 2019. The copper has not been an issue on Unit A2, due to the closed loop cycle. The Station also monitors air in-leakage online to prevent unnecessary impairment of condenser performance. Their cycle chemistry on both units is run so tight, that small leaks could cause operating problems.

By including routine maintenance, monitoring for in-leakage online, and by controlling water quality to minimize fouling, Station A has incorporated all technologies that can improve and maintain system performance. The personnel at the station know that good condenser operation is ideal for maintaining heat rate performance. Therefore, no other improvements to the condenser will reduce plant heat rate at Station A.

#### 7.3.2.4. Boiler Feed Pumps

Boiler feed pumps consume a large quantity of the auxiliary power used internally within a power plant. Overhauling the boiler feed pumps can yield heat rate reductions depending on the size of the unit and the original design of the pumps.

Units A1 and A2 are equipped with turbine driven boiler feed pumps. Its steam turbine drive allows the pump to operate at variable speed which maintains the pump at its maximum efficiency. The rotors were changed on the turbine drive for better efficiency to bring performance back to design level. In general, Station A personnel refurbish pumps to like-new conditions every 10-12 years. Because the units already perform best operating and maintenance practices on the boiler feed pumps, no other large improvements are considered to be feasible for future heat rate reductions.

### 7.3.3. Flue Gas System

#### 7.3.3.1. FD, ID, and PA Fan Improvements

When the FGD was installed on Unit A1, the SCR booster fans were replaced with larger axial ID fans to overcome the additional flue gas path pressure drop and conversion to a balanced draft system. During the FGD project on UnitA2, the centrifugal ID fans were replaced with axial fans. It is estimated that the conversion of the centrifugal to axial fans on Unit A2, which occurred at the same time the FGD was installed, mitigated some of the heat rate penalty that otherwise would have been experienced based on the overall aux power increase. On Unit A2, the FGD project also incorporated a re-design of flue gas discharge from the FGD. This provided a savings of approximately 1.5 in.wc. of draft pressure to the flue gas path. This was estimated to provide 7 Btu/kWh savings due to the decreased amount of work required by the ID fan. This savings, along with the axial fan conversion savings are far surpassed by the increased aux power loading associated with the FGD system.

The FD fan motors have two speeds on Unit A1, 4,500hp and 3,000hp. Fan motor speed settings can be changed on-line or during outages, and typically occurs between summer and winter months. Due to the change in atmospheric temperatures, the lower fan speed is sufficient during the winter months, saving approximately 1MW of aux power with the speed switch; however, this is only a temporary change that provides savings for three to six months of the year. The unit employs good operational practices by using a dual speed motor on this unit; however, the annual heat rate savings is minimal. The FD fans on Unit A2 do not have this feature.

There is no further potential heat rate reduction applicable to the ID fans on Unit A1 or A2 since axial fans are operated very efficiently at lower flue gas volumes, unlike centrifugal fans. The existing FD fans on Units A1 and A2 are all centrifugal; therefore there is the potential to convert the fans to axial configuration or install VFDs. However, this may not yield any measurable benefit on Unit A1 as this unit already has a two-speed FD fan. It is possible to install a two-speed motor on the Unit A2 FD fans, similar to Unit A1. This could provide a similar heat rate savings for less than half the year. Since these units are base loaded, these options have limited value and were not further explored for FD fans.

#### 7.3.3.2. Fan VFDs

The primary air (PA) fans supply the air required to transport the pulverized coal to the burners. The PA fans at Station A are the original centrifugal fans. The six PA fans on Unit A2 were retrofitted with VFDs. These were installed in 2001 and have provided significant auxiliary power savings. This aux power savings is equivalent to approximately 43 Btu/kWh in heat rate savings. The Unit A1 PA fans do not have this feature. Unit A1 currently operates around 77% capacity factor and Unit A2 near 79%. Since the units are currently base-loaded, the implementation of VFDs on the PA fans on Unit A1 would provide very little improvement in operation. The reason why Unit A1 cannot achieve similar heat rate improvement with VFDs on the PA fans is due to the fans originally having a narrower design fuel range; therefore they are accurately sized for the fuel currently burned.

The centrifugal FD fans on either unit are not equipped with VFDs; therefore, the unit could experience some benefit if the FD fans were retrofitted with VFDs. However, since the units are base loaded, it is unlikely that VFDs on the FD fans would improve heat rate with base-loaded operation. However, the high air pre-heater in-leakage currently occurring on Unit A2 may be causing the fans to operate lower than their optimal efficiency point. VFDs might be beneficial to implement on Unit A2's FD fans if air heater in-leakage continues to operate in a similar leakage range after the seal improvements, due to operation at non-optimal efficiency points.

### 7.3.4. Air Pollution Control Equipment

#### 7.3.4.1. Flue Gas Desulfurization (FGD) System

As mentioned earlier, Station A is equipped with WFGD systems on the two units. When the new FGD systems were installed (Unit A1 prior to 2012 and Unit A2 after 2012), they required absorber bleed pumps, gas cooling pumps, reclaim water pumps, and oxidation air blowers, which have increased the total auxiliary power loading on the units by 14 MW. The increased aux power consumption was partially offset by other projects on each unit. Unit A1 completed ESP improvement, turbine rebuild, and conversion to balanced draft during the FGD project, which led to a 17MW increase in auxiliary power and approximately 300 Btu/kWh net heat rate increase. Unit A2 installed VFDs on the PA fans, converted to axial style ID fans, and rearranged the flue gas path to minimize pressure drop during the FGD project, which lead to an 11 MW increase in aux power and approximately 190 Btu/kWh net heat rate increase.

#### 7.3.4.2. Particulate System

Approximately 75% of the coal-fired electric generating units in the U.S. use ESPs to control particulate emissions. ESPs operate by routing the particulate laden flue gas through a vessel that is divided into multiple, vertical sections. Each section is energized with an applied voltage that creates an electric field between a discharge electrode (DE) and a collection electrode (CE). The electric field ionizes the particles entrained in the flue gas and enables their capture on the CE plates. At specific intervals, the plates are shaken and the particles are dislodged and fall into hoppers for collection and removal. In order to improve the power utilization, utilities have increasingly made use of ESP energy management systems. The EMS enables the ESP to be optimized for varying load conditions by adjusting T/R set operation to maintain the unit's required opacity limit.

Unit A1 is equipped with a cold-side ESP (CESP), while Unit A2 is equipped with a hot-side ESP (HESP). The CESP does not include an EMS. Instead, the unit employs the best plate design available. This plate design works well in high sulfur environments. In the mid-1990s, a partial plate replacement was completed to get the system back to design efficiency. Unit A2 has EMS installed on the HESP, where the T/R sets' power increases or decreases based on measured opacity. The system has also undergone an electrode improvement during the time the unit switched to firing a high-sulfur fuel.

Unit A2 is already equipped with an EMS system on its HESP to optimize power output of the electrodes. Theoretically, an EMS system could be installed on Unit A1 to reduce auxiliary power costs. However, the MATS rule requires controlling non-mercury metals, for which most affected facilities, including Station A, will use filterable particulate matter (FPM) as a surrogate, as permitted by the rule. Because the FPM limits prescribed by the MATS rule are relatively low (0.03 lb/MMBtu), ESPs will be utilized to maximize their collection efficiency by operating all T-R sets; therefore, an EMS system may not result in any reduction in heat rate.

#### 7.3.4.3. Selective Catalytic Reduction System

SCR systems were installed on Units A1 and A2 before 2005 for increased NOx emissions reduction. The system uses direct injection of ammonia into the flue gas path. With the addition of the SCR reactor and ancillary equipment, the auxiliary power consumption increased. The increase in auxiliary power consumption is due to (1) increased ID fan power due to the added pressure drop across the new ductwork and SCR reactor and (2) ancillary equipment including reagent preparation, catalyst cleaning equipment, and equipment associated with ammonia injection. The added auxiliary power consumption due to the new SCR system has led to an overall increase in heat rate of approximately 100 Btu/kWh.

The units currently monitor catalyst life with test modules, rather than catalyst layer pressure drop as part of their catalyst management plan. To reduce pressure drop in the system, either ductwork improvements, a lower degree of mixing, or switching the type of catalyst management plan would be required. The SCR ductwork and mixing were designed with state-of-the art modeling technologies to optimize pressure drop while providing the degree of mixing required to achieve sufficient $NO_X$ reduction. Because neither auxiliary power reductions nor pressure drop reductions are feasible at Station A, there are no further opportunities to lower heat rate associated with the SCR system.

### 7.3.5. Water Systems

#### 7.3.5.1. Boiler Water Treatment

Reduction of power plant heat rate as related to water treatment primarily involves maintaining the proper water chemistry to reduce boiler scale and to control solids and impurities. Boiler scale lowers heat transfer by lowering thermal conductivity. Heat transfer may be reduced significantly by the presence of scale. More important than the heat loss is that scale can cause overheating of the boiler tube metal and can result in subsequent tube failures, leading to costly repairs and boiler outages.

The plant practices careful monitoring and maintenance of the water treatment systems for optimal water quality. The feedwater system was changed to oxygenated feed water in the 1990s to reduce scaling. Ammonia is currently used to maintain a high pH (8.8 minimum) which helps with the oxygenated system and reduces scaling. The units have not reported any experience with scaling or overheating of the boiler tube material nor have they experienced any iron or copper deposition. Every three years, the station personnel take tube samples to check for thickness. In addition, every 10-15 years, chemical cleaning is completed.

Since the station already has advanced water treatment systems installed and high-quality water chemistry, there is no opportunity for further improvements regarding additional treatment technologies to reduce boiler scale and improve plant heat rate.

#### 7.3.5.2. Cooling Towers

Unit A1 is not equipped with a cooling tower; instead it uses once-through cooling from the river; therefore, no heat rate reduction strategies in this section are applicable. Unit A2 is equipped with a counter-flow cooling tower. The cooling tower was modified between 2005-2012 from cross-flow to counter-flow during the FGD project. The counter-flow mechanism resulted in an improvement of approximately 1-1.5°F of discharge water temperature, which provided an average heat rate reduction of approximately 0.09%.

### 7.3.6. Various Large Motors

In addition to the various methods of improving plant performance that have been discussed, there are other areas that can provide improvements on a plant-wide basis: VFDs and upgrade of large electric motors. The application of VFDs was discussed in Section 7.3.3.

The other potential area for heat rate improvements is the upgrade of large electric motor (>450 hp) by replacing older electric motors with new, energy efficient motors. The primary problems with implementing more efficient motors are the cost of the materials and the cost of training plant personnel on the proper maintenance procedures. All electric motors in the range of 1-200 hp sold today in the U.S. must meet high-efficiency standards as mandated by the federal government in the Energy Policy Act of 1992 (EPAct). Therefore, replacing older, failing motors will entail the inclusion of a more efficient motor.

As part of the regular maintenance plan at Station A, the large electrical motors are regularly maintained or refurbished and many have not been replaced. Due to the base load conditions at which these units operate, it is not expected that replacement of motors will deliver any real efficiency improvement. As noted in the previous sections, other motors, if replaced, will be of higher efficiency in the ordinary course of business. However, there does not appear to be sufficient gain in efficiency to justify premature replacement.

### 7.3.7. Station A Summary of Previous and Potential Improvements

Within this study, S&L evaluated the changes to the units' heat rate that occurred due to the improvements that have been implemented at Station A to date, as well as potential future heat rate improvements that are technically feasible. In Table 17 and Table 18, the changes in heat rate have been summarized to show the overall changes to the two units at Station A.

**Table 17: 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 heat rate 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 consumption 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 18: 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 heat rate 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 consumption was approximated at 11MW; however, this was partially offset by other projects that occurred at the same time, including axial fan conversion, VFD installation of 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.

### 7.3.8. Conclusions for Station A

The conclusion of the heat rate improvement audit for Station A on Unit A1 or A2 is as follows:

- Unit A1 increased heat rate by 2.4% since 2000 due primarily to the installation of wet FGD and SCR systems. Future potential heat rate improvement is limited to 0.6%.
- Unit A2 increased heat rate by 1.81% since 2000 due primarily to the installation of wet FGD and SCR systems. Potentially 2.1% future heat rate improvement is available.
- Continuation of good maintenance and operating practices is necessary to maintain the units' heat rates that are made possible by improvements completed in the past. In addition, the units' heat rates at the time of the audit may not be sustainable if the units' loads or dispatch change.

## *7.4. Station B*

Station B includes a compilation of three units that were audited as part of this study. Unit B1, B2, and B3 are subcritical pulverized coal units that are between 300-600 $MW_{NET}$. All three units are equipped with FGDs and baghouses.

This section of the report summarizes heat rate improvement strategies identified in the 2009 Report that are applicable on each unit and estimates the approximate reduction, both on a past and future basis for the units at Station B. Previous improvements to units that have resulted in heat rate reduction will be quantified to determine an overall achievement profile to-date. After considering improvements that have already been completed and the technical feasibility of the remaining strategies, this section will provide an overall profile of past and future unit heat rate reductions.

For heat rate improvements that have already taken place, the section below identifies what year the technologies were installed, what heat rate changes were observed, and if additional improvements would achieve further reductions in heat rate.

### 7.4.1. Boiler Island

This section of the report discusses equipment within the Unit B1, B2 and B3 boiler islands that offer potential improvements in plant heat rate:

- Material Handling
- Boiler operation/overhaul with new heat transfer surface
- Neural network system and intelligent sootblowers
- Air pre-heaters

#### 7.4.1.1. Material Handling

Material handling systems include coal, bottom ash, and fly ash handling. With respect to ash handling systems, heat rate improvements can often be realized by converting wet handling systems to dry handling systems by eliminating equipment and auxiliary power loads associated with the transport of water. The bottom ash systems on Units B1 and B2 are wet sluicing systems and have not been converted to dry handling. The bottom ash is sent to hydrobins (not ponds) and finally sent offsite dewatered. Unit B3 was originally equipped with the same type of wet sluicing system, but the system was later retrofitted to a submerged flight conveyor. This provided the unit approximately an 11 Btu/kWh heat rate reduction. A similar retrofit is possible on the existing wet sluicing systems at Station B. Retrofit projects were incorporated into the 20-year plans for Units B1 and B2; however, the station has not found an economic way to convert to dry handling, due to the predicted installed cost today being more than three times the cost per unit of the Unit B3 improvement. In addition, these improvements would require back-to-back outages on Units B1 and B2, due to the bottom ash systems being common, resulting in additional financial impacts due to outage scheduling.

All three units are equipped with dry FA handling systems. Flyash from Units B1 and B2 are sold for concrete, while the flyash from Unit B3 is sent offsite for disposal. The dry FA handling systems are already considered an efficient handling system, and would not achieve any further heat rate reduction with improvements.

Only like-kind replacements of coal mill motors have been made at Station B. The plant employs best operating and maintenance practices with coal motors; no additional heat rate improvement is predicted. The pulverizers are providing a product that gets 80% through 200 mesh. This has helped provide the units with very low unburned carbon levels.

#### 7.4.1.2. Boiler Operation/Overhaul with New Heat Transfer Surface

Adding heat transfer area to boiler surfaces is a possible methodology for reducing plant heat rate. No additional heat transfer surface area has been added to any of the three units since its original design. The reheaters are still the original on all three units. Some sections of the superheater have been replaced like-kind on all three units after 30 years of operation. No additional heat transfer surface was added during this process; therefore, the unit did not experience any heat rate improvement.

Adding surface to improve the steam temperatures beyond the original design values would require a major evaluation of all affected pressure parts and typically is not economical. The units at Station B have the original heat transfer surface area that was designed for the units. The station personnel employ the best operating and maintenance practices in regards to the boiler heat transfer surface area and are not predicted to gain any benefit from additional surface area.

#### 7.4.1.3. Neural Network and Intelligent Sootblower System

Computer models, known as neural network (NNs) simulate the power plants at various static and dynamic loads, with the predicted performance results correlated to several real-time process measurements. Neural network control systems can be used to optimize emissions such as $NO_X$ and CO, as well as help optimize boiler efficiency.

No unit at Station B has NN installed. The current group of burner/boiler engineers has OEM experience. These engineers have completed parametric testing that has helped optimize boiler operation. The boiler optimization has also helped provide consistent unburned carbon levels which are required for ash sales. Unit B1 and B2 typically have only 1% unburned carbon. The frequent tuning of the combustion system to optimize CO and fuel to air ratio results in these unburned carbon levels and a lower heat rate. Unit B3 does not sell flyash.

The use of intelligent soot blower (ISB) systems for improving system efficiency enhance the performance of the furnace and longevity of the tubing material, while minimizing cycling effects to the steam turbine. The ISB system functions by monitoring both furnace exhaust gas temperatures and steam temperatures to identify affected areas that require soot blowing.

The units at Station B are not equipped with ISB systems. The units are equipped with compressed air sootblowers, which are used almost constantly at full load. The low NOx burners (LNB) and over fire air (OFA) are the causes of heavy slagging/fouling of the backend.

Due to the station's employment of best operational and maintenance practices, it is not expected that any heat rate benefit would be achieved with the installation and operation of a NN system. In addition, the units are already equipped with sootblowers that operate almost continuously at full load operation. It is not predicted that the incorporation of an intelligence portion would provide heat rate reduction.

#### 7.4.1.4. Air Pre-Heaters

Air pre-heaters are an important component of maintaining efficiency at a power plant. Such systems provide heat recovery to the unit by cooling the flue gas counter-currently with incoming pre-combustion air. Cooling of the flue gas transfers contributes to increased efficiency by recovering heat that raises combustion air temperatures and minimizes moisture in the coal prior to its combustion. With respect to air pre-heaters' contributions to plant heat rate, two possible methods to improve their performance are as follows:

- Minimizing air pre-heater leakages from the air-side to the flue-gas side. High air pre-heater leakage raises auxiliary power requirements due to processing higher volumes of gas in downstream equipment, such as ID fans, and upstream equipment, such as FD fans.
- Lowering air pre-heater outlet temperatures by controlling sulfuric acid dew point with alkali injection, allows for recovery of additional heat into the combustion air with added heat transfer surface.

##### *7.4.1.4.1. Minimizing Air Pre-Heater Leakage*

All units at Station B are equipped with Rothemühle style air heaters. With the discontinued use of the HESP on Units B1 and B2, the air heaters operate under high ash conditions, so improvements were made. No improvements were made to the air heater on Unit B3.

The air heaters were designed for 10% in-leakage, but the units operate closer to 11% typically. In-leakage can get up to 15% after three years of operation, but the rates are returned to design conditions coming out of the maintenance outage. Every three years the air heaters are maintained by inspection and change as required.

The Rothemühle style air pre-heaters at Station B typically operate only a few percentages above their design rate. After approximately three years, the leakage rate can increase to 5% above design values; however, these leakage rates are far below many utilities experience with this style of air heater. The station personnel employ the best possible maintenance and operating practices to mitigate leakage rates on this type of air pre-heater. The idea of converting to a low-leakage Ljungström air pre-heater is not necessary on this unit. Continued repair to APH components and inspection and replacement of seals as required will help maintain their current average in-leakage rates.

*7.4.1.4.2. Lower Air Pre-Heater Outlet Temperature by Controlling Acid Dew Point*

The air heater outlet temperature typically is controlled at 20-30°F above the sulfuric acid dew point to minimize corrosion of cold-end baskets. To enable lower air heater outlet temperatures, dry sorbent injection (DSI) can be installed in order to remove $SO_3$ and lower the acid dew point temperature. This technology is generally applied to medium- to high- sulfur fuel applications. However, the units at Station B fire low-sulfur western bituminous coal (sulfur content typically below 0.5 wt%).

Since the units fire a low-sulfur fuel and are not equipped with and SCR, very low $SO_3$ concentrations are present at the air heater inlet. DSI equipment vendors typically do not guarantee $SO_3$ emissions below 5 ppmvd at 3% $O_2$; therefore, this technology is not feasible.

The potential for a future SCR retrofit would likely preclude the unit from reducing the APH outlet temperature, thereby preventing additional heat recovery.

### 7.4.2. Turbine Island

This section of the report discusses improvements that have been or could be made to Station B units' equipment within the turbine island that offer potential reductions in plant heat rate, including the following:

- Turbine overhaul
- Feedwater heaters
- Condenser

#### 7.4.2.1. Turbine Overhaul

Technological advancements have improved the efficiency and longevity of steam turbines compared to the turbines that were originally installed in many older units. Advanced design tools, such as CFD modeling, have significantly enhanced turbine design capabilities that have led to increases in turbine efficiency. Additionally, the fabrication of increasingly complex geometric components has been developed to streamline design and efficiency. (Refs. 3, 4, 5, 6, 7, 8, 9, 10, 11, 12)

As part of a large environmental improvement project, Units B1 and B2 completed turbine maintenance that helped improve unit efficiency slightly. The improvement helped decrease the overall unit heat rate after the project by 214 and 183 Btu/kWh for Units B1 and B2, respectively.

All three units at Station B have made improvements to the HP/IP and LP turbine sections during the past 10 years. Based on monthly heat rate and unit efficiency historical data provided prior to and after the Unit B3 turbine improvement, it was estimated that on average an approximate 180 Btu/kWh heat rate improvement was achieved per unit. Similar heat rate data was not provided for the Unit B1 and B2 improvements; however, gross load data was provided prior to and after the improvement, which estimates approximately 355 Btu/kWh heat rate reduction, per unit.

These turbine improvements on all three units utilized the most technologically advanced turbine packing. No further improvements are expected for the units.

#### 7.4.2.2. Feedwater Heaters

Feedwater heaters are used within a power plant's thermal cycle to improve overall efficiency by recovering as much heat as possible into the boiler feedwater. The number and placement of feedwater heaters are determined during the original plant design and are highly integrated with the overall performance of the steam turbine. The heat used to increase the feedwater temperature is supplied directly from the thermal cycle in the form of steam extracted at various turbine sections.

Unit B2's feedwater heater has been maintained through the replacement of like-kind components. No heat rate reduction was experienced. The units already perform best maintenance practices on the feedwater heaters, thus no other improvements are feasible for heat rate reductions.

#### 7.4.2.3. Condenser

By lowering the condensing temperature, the backpressure on the turbine is lowered, which increases its efficiency. A condenser degrades primarily due to fouling of the tubes and air in-leakage. Tube fouling leads to reduced heat transfer rates, while air in-leakage directly degrades the quality of the water. However, if a closed cooling system is used, cooling water quality can be controlled to a much higher degree.

The condenser tubing material on all three units has undergone improvements during the past 15 years. Since the improvements, the units experience the same performance, but all pluggage of tubes has been eliminated. No heat rate reduction was experienced from the improvement.

One potential reason why the improvements did not provide any heat rate reduction is because of the regular condenser cleanings. The station personnel use scrappers with water and air hydroblast as their method to clean the condenser tubes. The cleaning and minor maintenance typically happens during an outage every three years.

The closed-loop cooling systems on all three of these units are monitored rigorously for tube leaks. The chemistry is controlled tightly and the oxygen levels are monitored closely. When chemistry starts to deviate, helium leak detection is used. The leaks are then repaired/addressed when they are found.

By including regular maintenance, improving materials of construction, monitoring leakage, and by controlling water chemistry, Station B has incorporated all technologies that can improve and maintain system performance. Therefore, no other improvements to the condenser will reduce plant heat rate at Station B.

#### 7.4.2.4. Boiler Feed Pumps

The existing boiler feed pumps on all units are turbine driven single pumps. The pumps are considered to be slightly oversized, which provides robustness to the operational practices. Improvements are made on a regular basis to restore the pumps to design conditions. The main improvement program consists of swapping the pump rotor out every six years with a refurbished spare. In between these swaps, the pumps are inspected for damage. The station personnel typically monitor vibration of the rotor and oil condition along with level.

The units already perform best operation and maintenance practices on the boiler feed pumps, thus no other improvements are feasible for heat rate reductions.

### 7.4.3. Flue Gas System

#### 7.4.3.1. FD, ID, and PA Fan Improvements

The FD and ID fans on all three units are axial with variable pitch. The ID fans were enlarged on B1 and B2 when the station discontinued the use of their FGD bypasses. These improvements were made prior to 2005 for Units B1 and B2. The fans were updated as part of a large environmental project, which consisted of other plant improvements, as well as changing WFGD operation to scrub 100% of the flue gas. The fan improvements were made at the same time as other improvements on the unit, which decreased the overall unit heat rate by 214 and 183 Btu/kWh for Units B1 and B2, respectively. While some of the heat rate reduction is likely due to the ID/FD fan improvements, the remainder can be attributed to turbine maintenance and the discontinued use of the ESP.

The variable pitch axial fans are operated very efficiently at lower flue gas volumes; therefore VFDs are not applicable to the drives of the variable pitch axial fans. There is no further potential heat rate reduction applicable to the FD or ID fans on Unit B1, B2 or B3.

The primary air fans supply the air required to transport the pulverized coal to the burners. No work has been done on these fans that would have increased their efficiency.

#### 7.4.3.2. Fan VFDs

The FD and ID fans are not able to incorporate VFDs on their motors, due to being variable pitch axial configuration. The PA fans are centrifugal, and therefore could potentially experience some benefit at varying loads if they were retrofitted with VFDs. However, it is likely that the addition of VFDs on the PA fan motors would not provide additional heat rate reduction, since the VFDs typically only provide heat rate performance optimization when the units often cycle or operate at low loads. The current capacity factors of all three units are greater than 85% and are projected to maintain similar high levels of operation in the future; therefore, it is predicted that no heat rate reduction can be experienced from this potential retrofit.

### 7.4.4. Air Pollution Control Equipment

#### 7.4.4.1. Flue Gas Desulfurization (FGD) System

All three units at Station B are equipped with FGD systems. Unit B1 and B2 are equipped with WFGD systems and Unit B3 is equipped with dry lime FGD. The absorber towers on Unit B1 and B2 scrub 100% of the flue gas for $SO_2$ reduction.

With typical spray-tower absorbers, slurry pumps can be turned down at lower loads or lower sulfur levels. However, the slurry spray levels of the Unit B1 and B2 systems cannot be turned down at lower loads. This is likely due to the slurry pump manifold design between the various spray levels in the absorber. If common pumps feed multiple spray headers, it is not possible to turn off a single level during low sulfur conditions or low load operation. In addition, the unit operates close to design sulfur and load conditions. Therefore, no pressure drop or aux power savings is possible and no heat rate improvement is feasible.

The dry FGD system on Unit B3 does not have any possible components for heat rate reduction.

#### 7.4.4.2. Particulate System

The majority of improvements that can be made to the particulate collection system for heat rate reduction are applicable to ESPs only. The original HESPs on Units B1 and B2 were discontinued during the large environmental improvement project and replaced with fabric filters for PM compliance. Units B1 and B2 have pulse-jet fabric filters (PJFF) while Unit B3 is equipped with a reverse gas fabric filter.

The reverse gas system, when installed on Unit B3, was equipped with reverse gas fans which are periodically used to reverse the path of the flue gas flow to aid in bag cleaning. The reverse gas fans were eliminated. The unit now completes the gas flow reversal through the bag compartments via the discharge of the ID fan with the help of dampers. The project eliminated the use of two 200hp fans and motors; however, in doing so, the duty on the ID fan was increased. Overall, the unit still received a small heat rate improvement.

Fabric filters typically are unable to make additional improvements to achieve heat rate reductions. No future heat reduction is deemed feasible on any of the three units at Station B.

#### 7.4.4.3. Selective Catalytic Reduction System

The current NOx controls on the units consist of LNB and OFA; however, further NOx emissions reduction may be required in the future for all three units. The addition of a selective catalytic reduction (SCR) system on Unit B1 or B2 could result in a future heat rate increase of approximately 1% for each unit. The significant heat rate increase is due to the added pressure drop across the system and the auxiliary components required for catalyst cleaning and ammonia injection.

If selective non-catalytic reduction (SNCR) technology were to be incorporated on Unit B3, the installation would come with a heat rate penalty. While the system does not add pressure drop to the flue gas path, it adds a significant amount of water into the boiler, which requires more heat to evaporate, thereby, increasing net unit heat rate. The system also increases total auxiliary power consumption. Based on OEM information, the total amount of water and equipment added is likely to increase the heat rate by 0.3%.

### 7.4.5. Water Systems

#### 7.4.5.1. Boiler Water Treatment

Reduction of power plant heat rate as related to water treatment primarily involves maintaining the proper water chemistry to reduce boiler scale and the amount of boiler water blowdown needed to control solids and impurities. Boiler scale lowers heat transfer by lowering thermal conductivity. Heat transfer may be reduced significantly by the presence of scale. More important than the heat loss is that scale can cause overheating of the boiler tube metal and can result in subsequent tube failures, leading to costly repairs and boiler outages.

High-purity water reduces water and energy losses because less scale is formed and less water must be discarded in the blow down. By reducing the blow down amounts, more steam is available in the thermal cycle, thereby improving overall power plant efficiency and reducing heat rate.

Normal oxide scaling has been found in the boiler tubes of Unit B1 and B2 along with copper oxide deposition. The station personnel use hydrazine to raise the condensate pH. The plant reportedly practices careful best operating practices on the unit and have incorporated the use of ammonia to raise the B3 condensate pH.

Since the station already has advanced water treatment systems installed and high-quality water chemistry, there is no opportunity for improvements regarding additional treatment technologies to reduce boiler scale and improve plant heat rate.

#### 7.4.5.2. Cooling Towers

All units at Station B use cooling towers as part of their closed-loop cooling systems. Since 2012, the plant added a new high-efficiency fill. Due to the nature of the high efficiency fills used, the units must maintain a side-stream filtration system which sometimes requires blow down.

Each cooling tower fan has been improved with higher efficiency fan blades. The efficiency of this improvement was never recorded. The fan motors on Unit B3 may be retrofitted in the future. This may make some efficiency improvement; however, it is not quantified at this time.

### 7.4.6. Various Large Motors

In addition to the various methods of improving plant performance that have been discussed, there are other areas that can provide improvements on a plant-wide basis: VFDs and upgrade of large electric motors. The application of VFDs was discussed in Section 7.4.3.

The other potential area for heat rate improvements is the upgrade of large electric motor (>450 hp) by replacing older electric motors with new, energy efficient motors. The primary problems with implementing more efficient motors are the cost of the materials and the cost of training plant personnel on the proper maintenance procedures. All electric motors in the range of 1-200 hp sold today in the U.S. must meet high-efficiency standards as mandated by the federal government in the Energy Policy Act of 1992 (EPAct). Therefore, replacing older, failing motors will necessarily entail the inclusion of a more efficient motor.

As part of the regular maintenance plan at Station B, the large electrical motors are consistently refurbished and many have not been replaced. Due to the base load conditions at which these units operate, it is not expected that replacement of motors will deliver any real efficiency improvement. As noted in the previous sections, other motors, if replaced, will be of higher efficiency in the ordinary course of business. However, there does not appear to be sufficient gain in efficiency to justify premature replacement.

### 7.4.7. Station B Summary of Previous and Potential Improvements

Within this study, S&L evaluated the changes to the units' heat rates that occurred due to the improvements that have been implemented at Station B to date, as well as the potential future heat rate improvements that are technically feasible. In Table 19through Table 21, the changes in heat rate have been summarized to show the overall changes to the three units at Station B.

**Table 19: 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 heat rate 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 20: 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 heat rate 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 21: 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 heat rate 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.

### 7.4.8. Conclusions for Station B

The conclusion of the heat rate improvement audit for Station B is that no future potential heat rate improvement is available on Unit B1, B2, or B3.

- Unit B1 improved heat rate by 5.6% since 2000. No future potential heat rate improvement is available. The net potential changes identified for Unit B1 will degrade heat rate by 0.9%.
- Unit B2 improved heat rate by 5.3% since 2000. No future potential heat rate improvement is available. The net potential changes identified for Unit B2 will degrade heat rate by 0.9%.
- Unit B3 improved heat rate by 1.97% since 2000. No future potential heat rate improvement is available. The potential changes identified for Unit B3 will degrade heat rate by 0.3%.
- Continuation of good maintenance and operating practices is necessary to maintain the units' heat rates that are made possible by improvements completed in the past. In addition, the units' heat rates at the time of the audit may not be sustainable if the units' loads or dispatch change.

# 8. Sources

## 8.1. Technology Vendors

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

1. Alstom
2. Paragon

## 8.2. Surveyed Literature

The various literature listed below were surveyed as part of this study.

3. Brandt, C.; A. Tremmel; H. Klotz. "ALSTOM Steam Turbine Design of World's Largest Single Shaft Units in Most Advanced Ultra-supercritical Steam Power Plants," Proceedings from Power-Gen Europe, 26-28 June, 2007.
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