UNIT HEAT RATE IMPROVEMENT STUDY

AT SPRINGERVILLE GENERATING STATION

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Revision 1

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PROJECT 13295-001

PREPARED BY

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000
www.sargentlundy.com

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CONTRIBUTORS

PREPARED BY: NOV. 14, 2014
David H. Park — Date
Senior Environmental Associate

REVIEWED BY: W. A. Rosenquist — Nov. 14, 2014
William Rosenquist — Date
Technical Advisor

APPROVED BY: Raj Gaikwad — 11/14/2014
Rajendra Gaikwad — Date
Vice President,
Advanced Fossil Technologies

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EXECUTIVE SUMMARY

On June 18, 2014, the 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. Specifically, the EPA proposed to establish state-specific rate-based (or mass-based) goals for carbon dioxide (CO_2) emissions from the power sector, including existing fossil fuel-fired electric generating units (EGUs). Proposed emission goals vary from state to state.

The EPA's proposal includes four building blocks to lower GHG emissions from power plants. To establish each state's rate-based CO_2 emissions goal, 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 best practices and equipment improvements 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").

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. For each alternative, S&L quantified the potential heat rate improvement that may be achieved at a 200, 500, and 900 MW coal plant. 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.

Heat rate improvements described in the 2009 Report case studies were estimated at a conceptual level, and were not based on any site-specific detailed analysis. In addition, verification of actual heat rate improvements was not made to determine whether any of the changes were implemented and what actual heat rate improvements were realized based on detailed design. Furthermore, the case studies 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.

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)[1] However, based on a review of the 2009 Report, as well as a review of EPA's Goal Computation Technical Support Document, it is apparent that 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.

It appears EPA assumed heat rate improvements cited in the 2009 Report were additive and applicable to all coal-fired units, when the 2009 Report makes it clear that it would not be feasible to implement all of the examined alternatives to achieve the sum total of their heat rate improvements. Furthermore, the 2009 Report does not state any range of overall heat rate improvements that could be expected from implementing any combination of the examined alternatives. In fact, the case studies provided in the report estimated potential heat rate improvements of 4% and 1.2% for the 250 MW and 850 MW units, respectively. 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.

The purpose of this engineering study is to review the potential heat rate improvement strategies identified in S&L's 2009 Report and assess their feasibility to improve heat rate for the four units at Springerville Generating Station (SGS).

In both the 2009 Report and EPA's proposed regulation for GHG emissions for existing stationary sources, the areas of a power plant where efficiency improvement and heat rate reduction may be possible are:

[1] It should be noted that the pre-publication version of the proposed rule published on June 2, 2014 stated that "The [2009 S&L] study 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." (See, pre-publication version, page 168 of 645). However, that conclusion was not included in the 2009 Report. The 2009 Report did not state that heat rate improvements were additive, nor did the report conclude that heat rate improvements of 4 to 12 percent would be achievable for a typical coal-fired EGU. In the version of the proposed rule that was published in the *Federal Register*, EPA corrected this statement to make it clear that "EPA estimated" heat rate improvements of 415 to 1250 Btu/kWh, or 4 to 12% may be achievable on existing coal-fired EGUs.

- Boiler Island
- Turbine Island
- Flue Gas System
- Air Pollution Control Equipment
- Water Treatment System

This study identifies systems and equipment at Springerville Units 1, 2, 3, & 4 where efficiency improvements can be realized. This study also provides estimates of the resulting net plant heat rate reductions and the order-of-magnitude costs for implementation. To conduct this evaluation, S&L reviewed equipment data manuals, system description manuals, plant data, test reports, and documents received from the client for each of the units.

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

For each unit, two numbers were estimated based on this evaluation (1) percent change in heat rate achieved to date from original designed based on past repairs and (2) potential future percent improvements in heat rate. The following tables summarize these changes for Springerville Units 1, 2, 3, and 4. Negative values listed in the tables are considered to be improvements in the unit's heat rate while positive values represent penalties in heat rate.

Table ES-1 – Summary of Heat Rate Changes for Unit 1 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	0.0%	-0.26%
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	0.0%	-0.66% Note 3
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	-1.8 Note 4	-2.6 Note 5
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 6	N/A Note 6
Primary Air Fans	N/A Note 6	N/A Note 6
Air Pollution Control Equipment		
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**-1.8%**	**-3.52%**

Note 1: "BP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design. BP prevents significant degradation of the unit's performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: Heat rate improvement based on improvements from Unit 2 air pre-heaters. Expect similar heat rate changes due to similarities of Unit 1 and Unit 2 design.

Note 4: Based on heat rate improvements from the turbine HP/IP component repairs

Note 5: It is expected that the same heat rate improvements from the LP component repairs on Unit 2 will apply for repairs performed on the LP components for Unit 1.

Note 6: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

Table ES-2 – Summary of Heat Rate Changes for Unit 2 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	-0.26%	BP Continued
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	-0.66%	BP Continued
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	- 5.2%	BP Continued
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 3	N/A Note 3
Primary Air Fans	N/A Note 3	N/A Note 3
Air Pollution Control Equipment		
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**- 6.12%**	**0.0%**

Note 1: "BP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design. BP prevents significant degradation of the unit's performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

Table ES-3 – Summary of Heat Rate Changes for Unit 3 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	BP	BP Continued
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	BP	BP Continued
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	BP	BP Continued
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 3	N/A Note 3
Primary Air Fans	N/A Note 3	N/A Note 3
Air Pollution Control Equipment		
SCR System	BP	BP Continued
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**0.0%**	**0.0%**

Note 1: "BP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design. BP prevents significant degradation of the unit's performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

Table ES-4 – Summary of Heat Rate Changes for Unit 4 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	BP	BP Continued
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	BP	BP Continued
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	BP	BP Continued
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 3	N/A Note 3
Primary Air Fans	N/A Note 3	N/A Note 3
Air Pollution Control Equipment		
SCR System	BP	BP Continued
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**0.0%**	**0.0%**

Note 1: "BP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design. BP prevents significant degradation of the unit's performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

1. INTRODUCTION

1.1 PURPOSE

On June 18, 2014, The 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. Specifically, the EPA proposed to establish state-specific rate-based (or mass-based) goals for carbon dioxide (CO_2) emissions from the power sector, including existing fossil fuel-fired electric generating units (EGUs). 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. The building blocks included: (1) reducing CO_2 emissions (i.e., lb CO_2/MW-net) at individual affected EGUs through increased efficiency and 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. Based on this evaluation, and taking into consideration each state's current mix of generation resources, EPA established state-specific rate-based CO_2 emission goals.

The proposed rule does not explicitly require that each state follow the building block approach to achieve the emission guidelines. States will have the flexibility to use any combination of measures, or building blocks, most relevant to their specific circumstances and policy preferences. Although the proposed guidelines do not include CO_2 emission standards for individual sources, it is anticipated that most states will adopt the building block approach, and most state plans will require existing coal-fired EGUs to reduce CO_2 emissions through heat rate improvements.

To establish each state's rate-based CO_2 emissions goal, 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). The average 6% heat rate improvement (using 2012 as the baseline year) was determined be a reasonable target based on EPA's evaluation of technical alternatives to reduce heat rate that may be achieved at existing coal-fired EGUs through the adoption of best practices (e.g., turning off unneeded pumps, installation of digital controls systems, earlier like-kind replacement of worn components, etc.) and equipment replacement. Heat rate improvements that may be achieved by adopting best practices and equipment replacement 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").

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 projects to improve heat rate, including changes to the boiler, the steam turbine, control systems, high efficiency motors, and similar improvements known to result in system efficiency gains. For each alternative, S&L quantified the potential heat rate improvement that may be achieved at a 200, 500, and 900 MW coal plant. 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.

Heat rate improvements described in the 2009 Report case studies were estimated at a conceptual level, and were not based on any site-specific detailed analysis. In addition, verification of actual heat rate improvements was not made to determine whether any of the changes were implemented and what actual heat rate improvements were realized based on detailed design. Furthermore, the case studies 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.

In the preamble to the proposed rule, EPA stated that it "believes that implementation of all identified best practices and equipment improvements at a facility could provide total heat rate improvements in a range of approximately 4 to 12 percent." (79 FR 34859). 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)[2] However, based on a review of the 2009 Report, as well as a review of EPA's Goal Computation Technical Support Document, it is apparent that 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.

It appears that EPA assumed that heat rate improvements cited in the 2009 Report were additive and applicable to all coal-fired units, when the 2009 Report makes it clear that it would not be feasible to implement all of the examined alternatives to achieve the sum total of their heat rate improvements. Furthermore, the 2009 Report does not state any range of overall heat rate improvements that could be expected from implementing any combination of the examined alternatives. In fact, the case studies provided in the report estimated potential heat rate improvements of 4% and 1.2% for the 250 MW and 850 MW units, respectively. 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.

The purpose of this engineering study is to review the potential heat rate improvement strategies identified in S&L's 2009 report and assess their feasibility to improve heat rate for Tucson Electric Power's (TEP)Springerville Generating Station (SGS) Units 1, 2, 3, & 4.

[2] It should be noted that the pre-publication version of the proposed rule published on June 2, 2014 stated that "The [2009 S&L] study 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." (See, pre-publication version, page 168 of 645). However, that conclusion was not included in the 2009 Report. The 2009 Report did not state that heat rate improvements were additive, nor did the report conclude that heat rate improvements of 4 to 12 percent would be achievable for a typical coal-fired EGU. In the version of the proposed rule that was published in the *Federal Register*, EPA corrected this statement to make it clear that "EPA estimated" heat rate improvements of 415 to 1250 Btu/kWh, or 4 to 12% may be achievable on existing coal-fired EGUs.

In both the 2009 Report and the EPA's proposed regulation for greenhouse gas (GHG) emissions for existing stationary sources, the areas of a power plant where efficiency improvement and heat rate reduction may be possible are:

- Boiler Island
- Turbine Island
- Flue Gas System
- Air Pollution Control Equipment
- Water Treatment System

This study identifies systems and equipment at SGS Units 1 through 4 where net plant heat rate improvement may be realized. Further, this study provides estimates of the change to the net plant heat rate as well as the corresponding order-of-magnitude costs for implementation, where applicable. This study also identifies potential heat rate penalties due to future emission controls. Additionally, S&L reviewed changes made to equipment or systems in the past and evaluated impacts to net plant heat rate. To conduct this evaluation, S&L reviewed equipment data manuals, system description manuals, plant data, test reports, and additional information obtained from TEP for the SGS units.

1.2 STUDY SCOPE

The following systems were identified in the 2009 report for efficiency and heat rate improvements:

- 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), induced draft (ID) fan improvement, and primary air (PA) fans
  - Variable Frequency Drives (VFDs)
- Air pollution control equipment

   - Flue gas desulfurization (FGD) system
   - Particulate system - Baghouses
   - Selective catalytic reduction (SCR) system
- Water treatment system
   - Boiler water treatment
   - Cooling tower

S&L has evaluated each of the above areas to determine the potential for changing the heat rate at the SGS Units. This was performed in two phases. The first phase involved an assessment of which of the above technical alternatives would be feasible for the SGS Units. For technical alternatives that are determined to be feasible, S&L estimated the impact to unit heat rate. This report documents the following:

- Identification of technical alternatives and/or operating practices that would likely improve plant efficiency at the Springerville units;
- Estimated reduction in unit heat rate resulting from implementation of the technical alternatives or operating practices determined to be technically feasible; and
- Improvements to unit heat rate achieved to date due to projects already undertaken at the plant.
- Commercial availability and current industry application of the technical alternative or operating practices, where required, and
- Impacts on balance of plant at the SGS Units, where required.

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

1.3 STATION BACKGROUND

Springerville Generating Station is a four-unit station, part-owned by Tucson Electric Power (TEP), Tri-State Generation & Transmission, and Salt River Project (SRP). Although TEP is a partial owner of the station, they are the primary operators of the four units; as such, this Study will refer to TEP as the representative owner. Springerville Station is located near Springerville, Arizona and includes four units – two nominally 390 MW_{NET} (Units 1 & 2) and two nominally 410 MW_{NET} (Units 3 & 4) boilers. Units 1 and 2 are pulverized coal units with Combustion Engineering boilers that burn subbituminous fuel from northwest New Mexico. Unit 1 was placed in service in 1985 and Unit 2 in 1990. With regard to their air quality control technologies, Units 1 and 2 are equipped with low NOx burners with secondary overfire air, spray dryer-type dry FGD systems for SO_2 mitigation, and reverse-air baghouses for particulate matter (PM) control.

Units 3 and 4 are pulverized coal units with Foster Wheeler boilers currently burning PRB fuel. The start-up years for Units 3 and 4 were 2006 and 2009, respectively. These units are currently equipped with selective catalytic reduction technology for NOx control, spray dryer-type dry FGD systems for SO_2 control, and pulse-jet fabric filters for PM control. Unit 4 was constructed with an activated carbon injection (ACI) system for Hg control. In addition, to promote oxidation and facilitate Hg removal, calcium bromide systems are currently being installed on Units 3 and 4.

1.4 KEY ASSUMPTIONS

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

- For the potential heat rate improvement alternatives related to power savings, an estimated change in auxiliary power was used to estimate the net heat rate change. Since the EPA 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 results in higher heat rates because units are designed to optimize efficiency at full load.
- The net heat rate calculations for Units 1 and 2 were based on improvements made from the original 380 MW_{NET} rating.

2. POTENTIAL MODIFICATIONS BASED ON 2009 REPORT

This section of the report addresses the potential for implementing heat rate improvements identified in the 2009 Report. For technologies that have already been installed at the Springerville units, the sections below identify what year the technologies were installed, what heat rate changes were observed, and if additional improvements would achieve further reductions in heat rate. For technologies that have not been installed at these units, the sections below identify whether the technology is feasible and estimate the heat rate benefits for those applicable technologies. For technologies that best maintenance practices (BP) are currently being implemented by the plant, current practices are noted and no improvements are achievable.

2.1 BOILER ISLAND

This section of the report discusses equipment within boiler islands that offer potential improvements in plant heat rate. The following are addressed:

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

2.1.1 Material Handling

Material handling systems include coal, bottom ash, economizer ash, and fly ash handling. With respect to coal handling systems, the use of more efficient motors can improve overall plant efficiency. Motor efficiency improvements are discussed in Section 2.6 of this report. With respect to ash handling systems, heat rate improvements may often be realized by converting sluiced material handling systems to conveyor type material handling systems and eliminating equipment and auxiliary power loads associated with the transport of high pressure water. The original bottom ash and economizer ash systems at the Springerville Units 1 & 2 were water sluiced material handling systems. The Unit 1 bottom ash handling system could potentially be converted to a submerged flight conveyor (SFC). As part of the SFC conversion, it is assumed that the economizer ash handling system would be converted to a dry flight conveyor (DFC) system, including a collection hopper and low pressure water pumps to transport the economizer ash from the collection hopper to the SFC. The auxiliary power savings from the conversion were reviewed and used to estimate heat rate improvements. The auxiliary power consumption of the wet ash handling system was estimated to be 1.0 MW while auxiliary power consumption for the dry ash handling system was estimated to be 0.08 MW. Based on the net load rate of the units, the reduction in heat rate was estimated to be approximately 0.26% per unit. Discussions with TEP indicated that this SFC conversion for Unit 1 is estimated to cost approximately $13.3MM ($36 per kW).

Unit 2 was converted to a SFC in 2010 and Units 3 and 4 were originally equipped with SFC ash handling systems; therefore, no further improvements to these systems can be made to reduce heat rate beyond utilizing more efficient motors, which is discussed in Section 2.6 of this report.

All four SGS units were originally equipped with dry, fly ash handling systems, which are considered efficient material handling systems; therefore, no further improvements to these systems can be made to improve heat rate beyond utilizing more efficient motors, which is discussed in Section 2.6 of this report

2.1.2 Boiler Operation/Overhaul with New Heat Transfer Surface

Adding heat transfer area to boiler surfaces is a possible methodology for reducing plant heat rate. The replacement of superheater and reheater tubes is part of a general maintenance practice that can recover heat transfer performance that has been lost over time. Adding surface area to improve the steam temperatures beyond the original design values would require a major evaluation of all affected pressure parts and is typically not economical.

The Unit 1 and 2 boilers are currently on a 3-year outage cycle where the owner performs replacements of the water wall tubes. In general, routine inspections and maintenance is performed to replace boiler components in-kind to maintain the original boiler performance. For Units 1 and 2, no improvements to surface area have been made, the in-kind replacements 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 reasonably implemented to improve heat rate beyond best operating and maintenance programs. Units 3 and 4 are on the same 3-year outage cycle but the necessity for tube replacements is minimal due to the boilers being relatively new.

2.1.3 Neural Network and Intelligent Sootblower System

Computer models, known as neural networks (NN's) control the power plants' operation at various static and dynamic loads, with the 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. Units 1 and 2 were converted to a Foxboro DCS system in 2004 and 2005 from an L&N control system. Since then, component replacements have been made to keep the system up to date. These two units are regularly tuned for NOx and CO using the DCS and available CEMS readings for excess air, O_2, CO, and CO_2. The low NOx burners and secondary overfire air systems on Units 1 and 2 are adjusted accordingly for NOx control. TEP is currently operating their Foxboro DCS systems for optimizing their NOx and CO emissions and maintaining boiler efficiency. Units 3 and 4 are also equipped with Foxboro DCS system but utilize SCR technology for NOx control. TEP currently has an active plan in place for information adjusted, automated fine-tuning of the boilers and is currently using best operating and maintenance practices for controlling NOx and CO using the existing system and available CEMS readings for excess air, O_2, CO, and CO_2; as such, no additional heat rate improvements can be achieved.

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 the furnace exhaust gas temperatures and steam temperatures to identify affected areas that require soot blowing. In order to attempt knowledge-based soot blowing, TEP first installed strain gauges, which ultimately did not provide any benefit. Following that, TEP explored the use of water cannons with smart flux sensors for the system to teach itself when to operate, the duration of operation, and to determine appropriate water pressures. These were taken out of service once the operators observed that the water cannon system had detrimental effects on the tubing. The current soot blowing systems are separate PLC-driven control systems, which were provided by Clyde-Bergemann for Units 1 & 2 and Diamond Power for Units 3 & 4. Attempts were made to implement an ISB system in addition to exploring an alternate water cannon method. However, due to the ISB system providing no operational benefit and the water cannons damaging tubing, TEP currently utilizes operator-driven retractable soot blowers, when heat trends and observed buildup deems them necessary. TEP is currently employing best operating and maintenance practices so no additional heat rate improvements can be achieved.

2.1.4 Air Pre-Heaters

Air pre-heaters (APH) are important components for maintaining efficiency at a power plant. Such systems provide heat recovery to the unit by cooling the exit flue gas concurrently with heating the incoming pre-combustion air. This 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:

- Minimizing air pre-heater leakages from the air-side to the flue-gas side. Excess leakage raises auxiliary power requirements due to processing higher volumes of gas in downstream equipment.
- Allow for lower air pre-heater outlet temperatures by lowering acid dew point, which allows for recovery of additional heat into the combustion air.

2.1.4.1 Minimizing Air Pre-Heater Leakage

Units 1 and 2 have unique air-heater configurations. Each unit has four regenerative APHs - two primary and two secondary air pre-heaters. Two primary air fans feed ambient air, which is first preheated by steam coils, to the two primary air pre-heaters to provide hot air to the pulverizers. The forced-draft fans feed air, which is also preheated by steam coils, to the two secondary air pre-heaters to provide hot secondary air to the boiler. With regular use and typical degradation of the air heater seals, leakage occurs, where some fraction of air coming from the fans can cross over into the flue gas side. Data for APH in-leakage prior to and following the most recent 2014 outage was made available by TEP for Unit 2. Prior to the outage, the air in-leakage on the Unit 2 primary APHs was approximately 60%; the secondary APHs average 40%. During the Unit 2 outage, maintenance was performed on both the primary and secondary APHs, which involved replacements in-kind for degraded components for all three layers of the APH baskets. Inspection reports indicated that the replacements brought the primary and secondary air pre-heater leakages down to 25% and 10%, respectively.

Accounting for regular degradation over time and maintenance, it would be estimated that the in leakages for the primary and secondary APHs will average to approximately 28% and 13%, respectively, between maintenance periods. Reducing the in-leakage in the primary and secondary APHs can improve the Unit’s heat rate. The decrease in flue gas volume reduces the PA, FD, and ID fan auxiliary power consumption, providing slight improvements in heat rate. Reducing the primary APH in-leakage to achieve an average of 28% results in a heat rate improvement of 0.53%. Repairs to the secondary APH to achieve an average of 13% in-leakage would improve the heat rate by approximately 0.13%. The overall estimated heat rate improvement from repairs to the primary and secondary air heaters on SGS Unit 2 was 0.66%

Discussions with TEP personnel indicated that Units 1 and 2 experience similar levels of APH in-leakage, so the data received for Unit 2 prior to the outage is also applicable for Unit 1’s APHs in their current state. Thus, repairs to reduce the in-leakage of the primary and secondary APHs for Unit 1 are anticipated to yield heat rate improvements of 0.53% and repairs to the secondary air heaters are estimated to yield a heat rate improvement of 0.13%. Overall, a heat rate improvement of 0.66% can be achieved with repairs to the primary and secondary air pre-heaters at SGS Unit 1 with a capital investment estimated in a range between $2.5MM to $5MM ($7 to $14 per kW). This estimate is based on in-house data as air pre-heater vendors are hesitant to provide budgetary values prior to a detailed inspection of the current condition of the Unit 1 APHs. Moreover, the current conditions of the APHs on Unit 1 and the necessary repairs are difficult to predict due to residual damage that occurred upon start-up of the unit.

Units 3 and 4 are equipped with a single trisector air pre-heater each, with air heater in-leakages averaging around 10%, between maintenance cycles. This equipment is relatively new and regular inspections and repairs are made to these air pre-heaters. TEP should continue these best operating and maintenance practices.

2.1.4.2 Allow Lower Air Pre-Heater Outlet Temperature by Lowering Acid Dew Point

The air heater gas outlet temperatures are typically, at a minimum, 20-30°F above the sulfuric acid dew point to minimize corrosion of cold-end baskets. APH gas outlet temperature data obtained from TEP indicates that they operate within the margin to avoid sulfuric acid condensation. 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 TEP units fire low sulfur western subbituminous coal; so both the SO_3 concentration and the acid dew point are low compared to higher sulfur bituminous coals.

Units 1 and 2 do not have an SCR; as such, SO_3 is formed only by oxidizing SO_2 in the boiler. Testing conducted on Unit 1 in 2014 indicated that the SO_3 levels at the APH averaged below 5 ppmvd. This data is also indicative of SO_3 levels expected on Unit 2 because of identical designs of the two units. Typically, DSI vendors do not guarantee SO_3 emissions below 5 ppmvd at 3% O_2; therefore, this technology is not feasible for either Springerville Units 1 or 2.

The oxidative properties of SCR catalysts on Units 3 and 4 result in slightly higher SO_3 concentrations due to SO_2 to SO_3 oxidation that occurs across the SCR catalyst. Based on the catalyst design of 2% SO_2 oxidation across the SCR, and assuming all catalyst layers installed, flue gas concentrations of SO_3 upstream of the air pre-heaters are estimated to be about 5 ppmvd at 3% O_2. As previously noted, DSI vendors do not guarantee SO_3 emissions below 5 ppmvd at 3% O_2; therefore, this technology is not feasible for either Springerville Units 3 or 4.

It is important to note that all four units at SGS are equipped with DFGD technologies, which require a minimum flue gas temperature for proper operation and SO_2 control. As a result, the inlet temperature to the DFGD vessels should not be reduced.

In summary, lowering air pre-heater outlet temperatures at the SGS units is not technically feasible to avoid SO_3 and HBr condensation and to maintain the operating efficiency of the downstream DFGD systems.

2.2 TURBINE ISLAND

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

- Turbine overhaul
- Feedwater heaters
- Condenser

2.2.1 Turbine Overhaul

Technological advancements have improved the efficiency of steam turbines compared to the turbines that were originally installed in many older units. Advanced design tools, such as computational fluid dynamics (CFD) have significantly enhanced turbine design capabilities that have lead to increases in turbine efficiency. Additionally, the fabrication of increasingly complex geometric components has been developed to streamline design and efficiency.

TEP invested in new high pressure (HP) and intermediate pressure (IP) components, mainly new inner blocks and rotors, for Unit 1 in 2009. By performing these turbine component replacements, TEP reported that the unit was able to improve its heat rate by approximately 7 MW, or 1.8%. Similarly, Unit 2 had new HP/IP components installed in 2007, also with new inner blocks and rotors. In Q1 of 2014, TEP made improvements to the low pressure (LP) components on Unit 2. TEP reported that the overall heat rate gain on Unit 2 from HP, IP, and LP component replacements was approximately 20 MW, or 5.2%. It is expected that similar component replacements in the Unit 1 turbine LP section could offer an additional 10 MW, or 2.6% in heat rate improvements.[3]

Units 3 and 4 have commercial operating dates of 2006 and 2009, respectively. As the units are fairly new, no heat rate gains can be expected from making improvements to the turbines on these two units. TEP follows best operating and maintenance practices in performing turbine overhauls on an 8 to 10 year cycle.

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[3] For Unit 2, changes to the LP sections yielded similar heat rate improvements following changes made to the HP/IP sections. It was assumed that a similar trend would be observed following changes to turbine components on Unit 1. This evaluation assumes that the heat rate improvements from LP section changes on Unit 1 would be the same as what was observed following the HP/IP section improvements.

2.2.2 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.

The Springerville units perform regular maintenance on feedwater heaters in order to maintain performance near the original design; note, no leaks have been observed throughout the life of the feedwater heaters. With no reduction or increase in duty, the change to heat rate is considered to be 0%.

2.2.3 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, Springerville operates using a closed cooling system, where cooling water quality can be controlled to a much higher degree.

The TEP maintenance program includes routinely inspecting and cleaning the condenser tubes during planned outages every three years in order to maintain condenser performance. The condenser is cleaned with brushes as the Station has experienced good results from using this method. The condenser tube material was changed in 2004 for Unit 1 and in 2005 for Unit 2 from 90/10 Cu-Ni to Sea-cure stainless to minimize corrosion; heat transfer capabilities are identical to the original design. Units 3 and 4 were originally designed with Sea-cure tubes. TEP has reported no major degradation inside the condensers outside of typical deposits on the condenser tubes.

By including routine maintenance, appropriate materials to prevent corrosion, and by controlling water quality to minimize fouling, SGS has incorporated all technologies that can improve and maintain system performance. A review of the recent plant data indicates the back-pressures are close to the original design values, and as such, any improvements made to the condenser will not produce appreciable heat rate improvements.

2.2.4 Boiler Feed Pumps

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

The existing boiler feed pumps at Springerville are all motor-driven feed pumps. Units 1, 2, and 4 are motor-driven feed pumps with hydraulic couplings; Unit 3 has motor-driven boiler feed pumps with a direct drive. TEP's standard maintenance practice is to replace the feed pump barrels in kind every seven years, based on performance. These pumps are already designed for a very high operating efficiency and are regularly maintained using best practices; therefore, no heat rate improvement is considered to be feasible.

2.3 FLUE GAS SYSTEM

2.3.1 FD and ID Fan Efficiency

For Springerville Units 1 and 2, the induced draft (ID) fans are centrifugal type fans with variable inlet vanes for operation at various loads. They are provided with two-speed, high efficiency Westinghouse motors. Currently, no VFDs are installed on the ID fans. TEP personnel stated that the fans run at the higher speed setting during base load operation to provide the necessary pressure and flow to exhaust the flue gas through the chimney.

The Unit 1 and 2 forced draft (FD) fans are centrifugal type fans with variable inlet vanes for operation at various loads and are not equipped with VFDs. TEP personnel stated that the fans run at the lower speed setting during base load operation to provide the necessary pressure and flow to the unit. During periods of air-preheater pluggage, the fans are required to operate at the higher speed setting. Units 3 and 4 have variable inlet vane, centrifugal ID and FD fans. Currently, there are no VFDs on the ID or FD fans at Springerville Units 3 and 4.

All four units are currently base-loaded with capacity factors greater than 85% in years where the unit did not take a minor or major outage. For base-loaded units, VFDs on the ID or FD fan motors will not provide appreciable heat rate improvements. The VFDs typically only provide heat rate performance optimization when the unit operates for prolonged periods at low loads.

2.3.2 Primary Air Fans

The primary air fans supply the air required to transport the pulverized coal to the burners. The primary air fans at Springerville Units 1 and 2 are variable pitch axial flow fans equipped with 3500 HP high efficiency motors. The

PA fans on Units 3 and 4 are centrifugal fans. There are currently no VFDs installed on the PA fan motors and no improvements to the centrifugal PA fans on Units 3 and 4 have been made during their operating life. However, it is likely that the addition of VFDs on the PA fan motors would not provide significant heat rate improvement because, as stated above, VFDs typically only provide heat rate performance optimization when the units operate at low loads. Furthermore, the addition of VFDs on variable pitch axial flow fans is not used.

2.4 AIR POLLUTION CONTROL EQUIPMENT

2.4.1 Flue Gas Desulfurization (FGD) System

All four units at Springerville Station are equipped with spray dryer absorber (SDA)-type dry FGD systems.

The potential heat rate improvements in DFGD systems are:

- Improved flow distribution to lower the pressure drop

The auxiliary power consumption of the DFGD systems have been incorporated into the plant heat rate calculations as part of the base case. Currently, the DFGD systems are meeting the original design performance with all of the equipment in operation; therefore, it is not anticipated that improving flow distribution would have an impact on the heat rate. There are no additional opportunities for heat rate reduction for all the DFGD systems on the four units.

2.4.2 Baghouse

All four units at Springerville are equipped with baghouses for collecting the flue gas particulate matter and SDA byproducts. Baghouses operate by collecting dry particulate matter as the flue gas passes through filter membranes, which are bundled in tube sheets and enclosed in compartments. Similar to the SDA systems, these units were constructed with baghouses as part of their original design, with the fans having been sized for the expected pressure drop across the baghouse. The existing baghouses are currently operating within the original design performance with all the equipment in operation. In addition, TEP personnel have noted that all of the original flue gas distribution devices and flue gas turning vanes are intact. 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 four units at Springerville Station.

2.4.3 Selective Catalytic Reduction (SCR) System

Springerville Units 3 and 4 were originally designed with and currently operate SCR technology. As previously mentioned, these units are fairly new (Commercial Operation Dates: 2006 and 2009, respectively) and extensive flow modeling was performed to achieve NOx reduction efficiency with minimum ammonia slip. More importantly, these modeling efforts focus on achieving uniform flue gas distribution across the SCR catalyst with minimal pressure drop. In addition, TEP has confirmed that a catalyst management system has been implemented to save on pressure drop across the SCR. TEP is currently operating these SCR systems with the best operating and maintenance practices and heat rate improvements are not to be expected from changes to these systems.

2.5 WATER SYSTEMS

2.5.1 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 minimizing 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 blowdown amounts, more steam is available in the thermal cycle, thereby improving overall power plant efficiency. Springerville practices careful monitoring and maintenance of the water treatment systems for optimal water quality. Units 1 and 2 have inline condensate polishers while Units 3 and 4 operate Powdex resin for polishing. 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, reduce boiler blowdown and improve plant heat rate.

2.5.2 Cooling Towers

All four units at Springerville station operate using their original mechanical draft cooling towers; the cooling tower fans are not equipped with VFDs. The Unit 1 and 2 cooling tower fans are single speed with forward and reverse flow capabilities. During the winter months, the fan rotations are reversed to de-ice the system and maintain proper operation. Unit 3 and 4 cooling tower fans have two speed functionality, which allows TEP to operate them at lower speeds should ambient temperatures require less cooling. Furthermore, individual cooling tower cells are taken out of service during periods of cool weather in order to minimize auxiliary power consumption by the cooling towers. Since the cooling tower and cooling system are already operating effectively for the balance of the year, there is no opportunity for further economical improvements to the cooling tower systems. However, regular maintenance of the fill and water chemistry must be continued to reduce degradation of cooling tower performance.

2.6 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. Two additional methods that will be discussed in this section are variable frequency drives (VFDs) and upgrade of large electric motors.

Due to current electricity market conditions, many units no longer operate at base-load capacity and, therefore, VFDs on fans can enhance plant performance at off-peak loads. Additionally, because utilities are phasing in their environmental equipment improvements, new fans are oversized and operated at lower capacities until all additional equipment has been added. Under these scenarios, VFDs can improve the unit heat rate. VFDs as motor controllers offer improvements to electric motor power requirements. With unit loads varying throughout the year, the benefits of using VFDs on large-size equipment, such as FD or ID fans, boiler feedwater pumps, and condensate pumps can have significant impacts. However, due to Springerville Units 1-4 being base loaded, the addition of VFDs is not practical for the purposes of heat rate improvement.

The other potential area for heat rate improvements is the upgrade of large electric motors (>450 hp) by replacing older electric motors with new, energy efficient motors. 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.

All of the large motors at the Springerville units are 95% efficient or greater; therefore, it is not practical to install new motors for Springville Units 1-4 for the purposes of heat rate improvement.

3. SUMMARY AND CONCLUSION

Within this study, S&L provided the changes to the units' heat rate based on the plant improvements that have been implemented at TEP as well as the potential improvements that can be implemented. In the following tables, the changes in heat rate have been shown to summarize the overall changes to the TEP units.

Table 3-1 – Summary of Heat Rate Changes for Unit 1 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	0.0%	-0.26%
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	0.0%	-0.66% Note 3
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	-1.8 Note 4	-2.6 Note 5
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 6	N/A Note 6
Primary Air Fans	N/A Note 6	N/A Note 6
Air Pollution Control Equipment		
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**-1.8%**	**-3.52%**

Note 1: “BP” is defined as “Best Maintenance Practices” and incorporates consistent maintenance to sustain the unit’s heat rate at its original design. BP prevents significant degradation of the unit’s performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: Heat rate improvement based on improvements from Unit 2 air pre-heaters. Expect similar heat rate changes due to similarities of Unit 1 and Unit 2 design.

Note 4: Based on heat rate improvements from the turbine HP/IP component repairs

Note 5: It is expected that the same heat rate improvements from the LP component repairs on Unit 2 will be the same for Unit 1.

Note 6: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

Table 3-2 – Summary of Heat Rate Changes for Unit 2 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	-0.26%	BP Continued
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	-0.66%	BP Continued
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	- 5.2%	BP Continued
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 3	N/A Note 3
Primary Air Fans	N/A Note 3	N/A Note 3
Air Pollution Control Equipment		
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**- 6.12%**	**0.0%**

Note 1: "BP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design. BP prevents significant degradation of the unit's performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

Table 3-3 – Summary of Heat Rate Changes for Unit 3 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	BP	BP Continued
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	BP	BP Continued
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	BP	BP Continued
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 3	N/A Note 3
Primary Air Fans	N/A Note 3	N/A Note 3
Air Pollution Control Equipment		
SCR System	BP	BP Continued
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**0.0%**	**0.0%**

Note 1: “BP” is defined as “Best Maintenance Practices” and incorporates consistent maintenance to sustain the unit’s heat rate at its original design. BP prevents significant degradation of the unit’s performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

Table 3-4 – Summary of Heat Rate Changes for Unit 4 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date	Potential % to Change
Boiler Island		
Material Handling	BP	BP Continued
Boiler Operation/Overhaul with New Heat Transfer Surface	BP	BP Continued
Neural Network & Intelligent Sootblowers	BP	BP Continued
Air Pre-Heater		
Reduce Air Heater Leakage	BP	BP Continued
Reduce Flue Gas Acid Dew Point	BP	BP Continued
Turbine Island		
Turbine Overhaul	BP	BP Continued
Feedwater Heaters	BP	BP Continued
Condenser	BP	BP Continued
Boiler Feed Pumps	BP	BP Continued
Flue Gas System		
FD and ID Fan Efficiency	N/A Note 3	N/A Note 3
Primary Air Fans	N/A Note 3	N/A Note 3
Air Pollution Control Equipment		
SCR System	BP	BP Continued
FGD System	BP	BP Continued
Baghouse	BP	BP Continued
Water Systems		
Cooling Towers	BP	BP Continued
Boiler Water Treatment	BP	BP Continued
General		
Large Scale Motors	BP	BP Continued
TOTAL	**0.0%**	**0.0%**

Note 1: “BP” is defined as “Best Maintenance Practices” and incorporates consistent maintenance to sustain the unit’s heat rate at its original design. BP prevents significant degradation of the unit’s performance.

Note 2: Negative values listed indicate improvements in heat rate, and positive values would indicate a heat rate penalty

Note 3: No heat rate improvement is considered for the flue gas system due to the unit being base loaded as discussed in Section 2.3.

As shown in Table 3-1 above, Unit 1 has achieved an improved heat rate by an estimated 1.8% to date. There is also an opportunity to further improve the heat rate by an estimated 2.73% by converting the bottom ash handling system to a conveyor type, reducing the air pre-heater leakage, and performing a turbine overhaul.

Table 3-2 summarizes the heat rate changes for Unit 2 achieved to date and its potential for further improvements. Following the recent repairs to the air heat to reduce air pre-heater leakage; the overhaul of the HP, IP, and LP sections of the turbine; and the conversion of the bottom ash handling system, Unit 2 has achieved a heat rate improvement of 6.03%. TEP currently practices good maintenance practices so no further potential improvements were identified for Unit 2.

Table 3-3 and Table 3-4 summarize the heat rate changes for Units 3 and 4, respectively. The commercial operating dates for these two units were very recent, 2006 and 2009 respectively, limiting any opportunities for heat rate improvements. TEP should continue to implement best maintenance and operating practices on all four Units to reduce significant degradation on their heat rates.

4. REFERENCES

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