Response of Southwestern Electric Power Company
to the Arkansas Department of Energy & Environment
Division of Environmental Quality
Information Request Regarding Candidate Technologies
For John W. Turk (Turk Plant) Unit 1

1) <u>Neural Network/Intelligent Sootblower System Information</u>:

a) Please indicate whether each unit listed above is tied in to a neural network system to optimize the unit's operations and minimize emissions.

Turk Unit 1 does not utilize a neural network system for combustion optimization or any other operational system. Turk Unit 1 utilizes a Distributed Control System (DCS) and Process Information (PI) monitoring systems to provide the unit operators with a full view of the critical operating conditions on the unit. Sensors monitor temperatures, pressures, heat rate deviations on certain subsystems, various alarms, and certain market-based conditions. In addition to optimizing steady state operations, these sensors and related controls allow unit operators to make necessary changes in real time when the unit is required to change loads in response to automatic generator control by the regional transmission operator.

There is also a centralized Monitoring and Diagnostic Center (MDC) available to the AEP system units, which has the capability to monitor and trend individual data points remotely in real time, spot early trends, and proactively recommend actions to improve performance or eliminate a curtailment before costly damage occurs. Based on the information available through these systems, operators are able to distinguish between controllable and uncontrollable factors impacting heat rate on the unit, and take prescribed actions to reduce the impacts associated with controllable factors as much as physically and economically possible. Intensive operator training, including the use of a centralized control system generator simulator during that training, provides our personnel with the knowledge necessary to initiate appropriate changes in operating parameters, and monitor the effects of automated responses in certain supplemental control systems, to assure that stability is achieved and maintained during all operating conditions.

i. If a unit is tied in to a neural network system,

1. When was the neural network first operated?

Not applicable

2. What impact did this have on your heat rate?

Not applicable

ii. If a unit is not tied in to a neural network system and the technology is feasible,

1. Please quantify the cost to implement a neural network system for your unit.

As described above, there are presently sophisticated control systems, instrumentation and monitoring resources available to maintain stable and efficient control of the combustion process and other unit operations without the use of “neural network” technology. While it would be feasible and expensive to install additional sensors, optimizers and control systems which are available on the market today, the degree of improvement that could be achieved through this investment is not expected to achieve the levels identified in Table 1 of the ACE Rule. Turk Plant has not solicited any specific pricing for such a system, but has no reason to believe the cost would be significantly different that that listed in Table 2 of the ACE Rule.

2. Please quantify the expected heat-rate impact of implementation of a neural network system.

The opportunity for heat rate improvements with this technology is measured as a reduction of the typical heat rate increase that occurs over a long period of operating time. It is not an improvement in the design heat rate of the unit. In addition, the sensors, information, and controls must also be accompanied by actions necessary to make meaningful change in performance. While a neural network can expand the data points that are measured and monitored, it ultimately requires actions by both programmed control systems and experienced operators to start/stop and verify equipment operation or modify control settings to make meaningful change in performance. Turk Unit 1 is a very modern unit, designed and installed with integrated components and control systems, managed by experienced operators and which achieves a heat rate which is one of the lowest of all coal-fired generating units. Since heat rate deviation from design has historically been very low for Turk Unit 1 during its 8-year operating life thus far, addition of a neural network would result in only a marginal improvement that is less than the range predicted in Table 1 of the ACE Rule.

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Although technically feasible, the benefits of applying of this technology are limited for the reasons discussed above.

b) Is an intelligent soot blower system operated for any of the units listed above?

Turk Unit 1 is equipped with an intelligent sootblowing system that was installed with the original unit construction and went into service in 2012. The sootblowing system that was installed is a Sentry Series system which is a product of Diamond Power Company. The system also uses a B&W Power Clean heat flux monitor to assess conditions within the furnace and send commands to the sootblower control system.

i. If an intelligent soot blower system is operated for the unit, then please respond to the following questions:

1. Is the intelligent soot blower system incorporated into the neural network software? If so, does the impact you specified for 1)a)i.2. include the impact of the intelligent soot blower system?

No, this unit does not use a neural network for combustion or sootblower control. The sootblowers have the ability to be automatically controlled via the supplied control system or via manual override by unit operators as may be needed.

2. If the intelligent soot blower system is not incorporated into a neural network software package, then please respond to the following:

a. **When was the intelligent soot blower system first operated?**

The Diamond Power Co. intelligent soot blower system was installed new with the original construction and was put into service with original commissioning of the unit in 2012. The existing sootblowing system performance model and configuration controls will be replaced with a Babcock & Wilcox Co. (B&W) ISB Titanium System in Spring 2020.

b. **What impact did this have on your heat rate?**
Performance measurements to determine the impact of the sootblower systems on unit heat rate were not taken. These systems were installed primarily to reduce the risk of slag formation and potential unacceptable accumulation of ash on the heat transfer surfaces. Any heat rate "improvement" that is realized from these systems is in effect a reduction of the heat rate penalty being experienced against the unit design because of ash/slag buildup. These do not effectively improve the heat rate beyond the original design basis for a "clean" boiler, but when used effectively can maintain heat rate closer to the design value for a longer period of time.

ii. If an intelligent soot blower system is not operated for the unit and is technically feasible, then please respond to the following:

1. Please quantify the cost to install an intelligent soot blower for your unit.

Not Applicable

2. Please quantify the expected heat rate impact of the intelligent soot blower system.

Not Applicable

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Not Applicable.

c) **Please provide any other information relevant to DEQ's analysis of this candidate technology.**

Neural Network (NN) technology was developed and applied on a "test" basis to some steam generator equipment at other AEP units a decade ago. Reported results of the very controlled tests were highly variable and the technology focused on mainly one aspect (fuel-air distribution within the furnace) of the steam generation process. Testers concluded that the technology did not provide sufficient economic benefit to apply at full scale. Since that time, the implementation of the Mercury and Air Toxics Standards (MATS) rule has introduced increased regularity into the inspection, repair, and tuning of combustion controls. In addition, NN technology still requires manual coordination of several other processes, including starting and stopping large equipment such as pulverizers and fans, in order to maintain combustion stability within the steam generator. SWEPCO relies on well-trained and highly knowledgeable operators to perform this integrated control in a highly efficient and reliable manner without the use of NN's. The current use of the sootblowing system on Turk Unit 1 maintains a high level of steam generator cleanliness and no measureable additive heat rate improvement is anticipated to result from integrating a neural network for this unit.

2**) Boiler Feed Pumps:**

Large electric motor powered boiler feed pumps (BFPs) supply feedwater to the steam generator in some units, and are responsible for a large portion of the auxiliary power consumed within a power plant (up to 20 MW from a 600 MW unit). Rigorous maintenance is required to ensure reliability and efficiency are maintained. Wear reduces the efficiency of the pump operations and requires regular rebuilds/upgrades/overhauls. These improvements for electric boiler feedwater pumps reduce auxiliary power demands and improve *net* heat rate, but would not result in measureable improvements in *gross* heat rate.

At Turk Unit 1 the main boiler feed pump is driven by a steam turbine and not by an electric motor. As such, for most of the operating range of Unit 1 (above 30% output), the boiler feed pump is self-regulating and matches the steam needed to the load at which the unit is operating. In addition, it enhances the overall efficiency of the unit because of the reduced auxiliary electric demand (a reduction of as much as 35% of typical auxiliary load). For startup and low load operation, where there is insufficient steam yet available to supply the auxiliary drive steam turbine, a smaller motor-driven feed pump is used to provide the required feedwater. This pump is initially used during unit startup on the steam bypass system and prior to the electric generator producing any output and is removed from service at approximately 30% load. Boiler feed pump turbines can experience degradation and wear over time, and require periodic maintenance to repair turbine blades, exchange rotors, and restore steam seals. At Turk Unit 1, a regular turbine overhaul is planned approximately every 10 years, or after 80,000-100,000 hours of service. Given that the original design of this unit includes a more efficient technology for use above startup flow conditions, and the operator has adopted a regular schedule for overhauls of the pump and turbine, it is reasonable to conclude that no incremental improvement is currently achievable.

a) Over the past year, how does the performance of the boiler feed pumps for each unit compare to the manufacturer specifications?

The pump design is highly efficient and robust to withstand the rigor of numerous years of continued service with very little O&M required. The pump also maintains its efficient performance for the duration of the period between overhauls. During the past year, the feed pump has performed within the design specifications.

b) When was the last time the boiler feed pump(s) for each unit was overhauled or upgraded?

The main turbine-driven boiler feed pump was last overhauled and rebuilt in 2015 as a precautionary measure following an operation event (water hammer) which resulted in unusual pipe movement. The pump was found to be in acceptable condition but was rebuilt with an available new spare internal assembly. The startup motor-driven feed pump accumulates limited operation time and has not yet reached the service hours recommended for overhaul..

c) If the boiler feed pumps have not been overhauled or upgraded in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to overhaul or upgrade the boiler feed pump(s) for your unit.

Not applicable. The last overhauls were within specifications and within the performance period.

ii. Please quantify the expected heat rate impact of overhauling or upgrading the boiler feed pump(s).

Not applicable. Maintenance overhauls are performed on the feed pumps in order to maintain their capacity to perform reliably and uninterrupted during the operating periods. Any degradation is unlikely to achieve the amount that is projected within Table 1 of the ACE Rule. The internal condition of the pump must be maintained within manufacturer's specification in order to avoid operational failure and a forced outage.

iii. Please provide any other information relevant to the DEQ's analysis of this candidate technology.

Ultra-supercritical units using a single 1x100% capacity pump are not commonplace in the industry and thus the OEMs do not offer much in the way of efficiency improvements. AEP is not aware of any advanced designs for a steam-driven or electric motor driven boiler feed pump that could provide a heat rate improvement of 0.2%-0.5% above this unit's current performance as set forth in Table 1 of the ACE Rule.

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

The boiler feed pumps at this unit have been regularly maintained in accordance with manufacturer's specifications and additional overhauls are unnecessary.

3) <u>Please specify whether the air pre-heater for each unit listed above is regenerative (rotary) or recuperative (tubular or plate)</u>.

The two (2) air pre-heaters installed on Turk Unit 1 are tri-sector regenerative air heaters which do rotate.

a) If your unit has a regenerative air pre-heater, when were the seals last replaced?

The air heater seals were installed new as a complete set in 2012 when the unit was initially built and commissioned. Seals are inspected and maintained on an annual basis during maintenance outages as recommended by the air heater OEM. The sector plates are also inspected and have been found to be performing as per specification. This maintenance can include repairs to sealing components or replacement of partial sets of seals as necessary, based on damage or wear.

b) If the seals have not been replaced in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to replace the seals for the regenerative air pre-heater for your unit

As discussed above, the seals are inspected and maintained in accordance with the manufacturer's recommendations during regular outages. The costs for these inspections and repairs have not been separately tracked.

ii. Please quantify the expected heat-rate impact of replacing the seals.

The impact is very marginal since only partial set repairs or replacement are typically necessary due to extent of damage or wear. Continued replacements in accordance with past practice will allow the unit to maintain its historic efficiency.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

The improvement projected from this technique (upgraded air heater seals) results from limiting air in-leakage on regenerative air heaters by replacing air heater seals with newer designed low-leakage seals. Most units have some rate of air in-leakage, which can result in higher demand on the fans that provide air to the combustion zone in the boiler and higher auxiliary power demands.

For this unit, air heater seals are typically inspected, repaired or replaced with in-kind seals during equipment outages when the air heater baskets are replaced or when seals are found damaged. Additionally, the air heater internal ducts and sector plates are inspected during maintenance on the air heater, and localized repairs and stationary seal replacements can be made during those inspections if materials are available, or included in future outage plans. This unit is equipped with adjustable sector plates which provide for a more uniform seal throughout the temperature excursions caused by various unit load conditions.

There are products on the market that advertise lowering the amount of leakage experienced within air pre-heater equipment. While it is likely feasible to install such products on Turk Unit 1, it is currently AEP's opinion that the newer designs for low-leakage seals present risks to unit reliability and air heater functionality that may outweigh any efficiency gains. A thorough technical review is needed to determine applicability and potential benefits for Turk Unit 1. Plant operators currently use PI system screens for monitoring differential pressure, temperatures and flue gas pressure in the air heater and motor amps for the PA, FD and ID fans in order to assess air heater loading and performance. Application of the low-leakage seal design would require some level of detailed engineering and design by the boiler and/or air heater OEM(s) to determine a suitable method of application and to determine the potential benefits to be gained and reliability risks to consider in each specific case. A feasibility study has not been performed for this unit. Some leakage at this location is necessary to avoid air heaters "locking up" (not being able to rotate) which can lead to malfunctions, curtailments, or availability problems.

d) Please provide a detailed explanation if the technology or practice is not technically feasible or limited due to the unique characteristics of the unit.

See response to item c) above.

4) <u>Variable Frequency Drives (VFD) information for each listed unit:</u>

Variable Frequency Drives are available that work in concert with traditional electric motors to vary the speed necessary during unit load changes to maximize performance of the driven equipment and reduce losses. This results in a reduction of power consumption as an auxiliary load and helps to maximize the net electrical generation from the unit. The most effective applications are for electric driven boiler feed pumps that control feed water flow and induced draft fans that control air/gas flow through the flue gas path.

At Turk Unit 1, approximately 65 percent of the electric demand on a typical unit has already been addressed, including both of the major applications for VFDs identified in the ACE rule. First, the main BFP is driven by an auxiliary steam turbine that automatically adjusts to the required load and does not consume electricity. This pump/turbine combination is placed in service when the unit advances off of the startup system and achieves approximately 30% output and remains in service up through full load. Second, induced draft fans were provided on this unit during original construction and are axial flow fans with variable blade vane pitch, which reduce energy losses, enhance operator control, and increase volumetric flow through the unit to increase efficiency. The axial vane fans deliver substantially similar benefits as VFDs. In fact, in its 2009 report on coal-fired power plant heat rate reductions, Sargent & Lundy compared the benefits of centrifugal fans with VFDs to axial vane fans, and determined that the axial vane fans provided slightly superior performance. *Coal-Fired Power Plant Heat Rate Reductions*, Sargent & Lundy, Final Report on Project 12301-001 (Jan. 22, 2009) at p.8-5.

a) **Does your unit have VFD controls for the induced draft (ID) fans**?

No

i. If so,

1. When was the VFD first operated?

Not Applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not Applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the ID fans for your unit.

As mentioned in the paragraph above, Turk Unit 1 was able to install axial vane variable flow fans with conventional single speed motors for the induced draft fan applications when the FGD equipment was installed as part of original construction in 2012. SWEPCO does not have a true cost for adding a VFD onto an existing induced draft centrifugal fan. Power differential to operate the axial vane fans versus a conventional centrifugal fan and motor with VFD is negligible.

2. Please quantify the expected heat-rate impact of the installation and operation of VFD for ID fans for both base-load and cycling operating scenarios.

Based on the Sargent & Lundy report, SWEPCO anticipates that any difference would be negligible.

b) **Does your unit have VFD controls for the boiler feed pumps?**

No. As mentioned in Question 2 (Boiler Feed Pumps) above, the single main boiler feed pump is driven by a steam turbine. The auxiliary startup boiler feed pump is driven by an electric motor.

i. If so,

1. When was the VFD first operated?

Not applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the boiler feed pump(s) for your unit.

Application of a VFD to the auxiliary boiler feed pump drive motor would likely be cost prohibitive since the motor is approximately 5,000 HP, operates for a limited time only during startup when feed water flow is low and controlled by a regulating valve, steam components are being warmed from the bypass system and the electric generator is not connected to the grid (except for a limited period of time when the unit is producing less than 30% of rated MWs). This period would likely not be part of the emissions performance standard period of testing.

2. Please quantify the expected heat rate impact of the installation and operation of VFD for the boiler feed pump(s) for both base-load and cycling operating scenarios.

The impact of adopting a VFD to the auxiliary boiler feed pump motor would be extremely low, well below the suggested range offered in ACE Rule Table 1, as this motor is infrequently used and likely produce unmeasurable benefits.

iii. Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there is no electrical load consumed by the boiler feed pump over the majority of this unit's operating range (all loads above 30%), the design of the axial vane fans provide similar efficiency benefits, and the small motor used during start up operates only at low loads and infrequently, any benefits from applying VFDs would be well outside the range estimated by EPA and would not be cost-justified.

c) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

See response to item b)iii., above.

5) <u>Blade Path Upgrade (Steam Turbine) for each listed unit:</u>

The best candidates for blade path upgrades are those turbines experiencing steam leaks and blade erosion, where efficiency improvements can be achieved using computerized flow modeling and innovative materials. However, there is significant variation among units. These upgrades are large capital investments and require long lead times.

Turk Unit 1 is equipped with one high pressure turbine, one intermediate pressure turbine and two low pressure turbines. The turbine blade path was designed and manufactured to modern, efficient standards of the industry and was state-of-the-art when constructed and commissioned in 2012. This unit is unique on the AEP system. No spare turbine rotors exist so all components are either repaired or replaced if necessary during maintenance inspections.

a) Has the steam turbine for the unit been upgraded or overhauled in the past ten years? If so,

i. When was the turbine upgraded or overhauled?

Not applicable since the turbine has not been upgraded or overhauled to date.

ii. Describe how the turbine was upgraded or overhauled.

Not Applicable

iii. How did the upgrade or overhaul impact the unit's heat rate?

Not Applicable

iv. Are there further upgrades available that would improve the efficiency of the turbine?

None known. The degree to which the existing turbine blade path deteriorates or wears over time and service conditions will not be known until the initial turbine inspections are performed. Since the original blades were designed and manufactured to modern standards, it is not expected that significant incremental improvement in efficiency would be available with an upgrade. Only recoverable losses could be gained by performing the turbine overhaul and repair.

b) If not,

i. Please quantify the cost to upgrade or overhaul the steam turbine for your unit. (You may factor the costs associated with new source review, if it would be triggered by the upgrade, into your cost calculations.)

The steam turbine on Turk Unit 1 has not been upgraded in the first 8 years of its operating life since initial startup in 2012. In fact, no section of the steam turbine has yet undergone its initial opening and inspection (overhaul) which is currently scheduled for 2023.

Cost information for specific overhaul or upgrade projects is considered Confidential Business Information and is not included in this document. Budgetary information related to the future overhaul of the Turk Unit 1 turbine sections will be prepared in advance of the scheduled outage and will reflect that which is typical for turbines supplied by this specific OEM, including like-kind replacement of any worn or damaged parts. There has been no information gathered as of this time related to a potential upgrade of the steam turbine blade path on Turk Unit 1.

ii. Please quantify the expected heat rate impact of upgrading or overhauling the steam turbine.

No information related to improvements available from a turbine blade path upgrade is available for Turk Unit 1. The initial turbine overhauls are expected to produce opportunities to restore the turbine section efficiencies to near design condition, except for any damage mechanisms that result in non-recoverable losses (e.g. casing/seal distortion or inter-stage steam leaks). Such heat rate improvements are expected to fall in the lower end of the expected range of Table 1 in the ACE Rule.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Steam path inspections are performed during scheduled outages when turbine overhauls will allow for any liabilities to be addressed and for replacement parts to be procured and made ready for installation. There are no known current upgrade offerings that may be available for the turbine sections at Turk Unit 1. Any offerings in the future would need to be evaluated prior to commitment, forecasting of funds, procurement and implementation. The next regular maintenance opportunity for the turbines on Turk Unit 1 is currently scheduled for 2023.

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

Please see the responses to items b) and c), above. Also, incremental improvement of any blade path upgrade is likely not economically justified based on modern design of currently installed blades.

6) <u>Economizer for each listed unit</u>

Replacing or redesigning the economizer can optimize temperatures at the exit of the boiler. Boiler layout and construction may limit the applicability of this measure to certain units.

a) When was the economizer last replaced?

The economizer on Turk Unit 1 is original and has never been replaced. On occasion, there has been a need to locate and access certain areas of the economizer to address leaking tubes or other physical damage. This repair could result in replacement of a small number of tubes or partial tube sections but no major replacement of tube bundles has been necessary.

b) Throughout the past year, how does the performance of the economizer for each unit compare to the manufacturer specifications for a new unit?

During the past year, the economizer on Turk Unit 1 has performed well, allowing for critical temperatures such as boiler exit gas and air heater gas outlet temperatures to remain within manufacturer specifications throughout the load range.

c) If the performance of the economizer for a unit has degraded outside the performance range of the manufacturer's specifications:

i. Please quantify the cost to redesign/replace the economizer for your unit.

Not applicable

ii. Please quantify the expected heat-rate impact of redesigning/replacing the economizer.

Not applicable

d) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there are currently no issues with the performance of the existing economizer, and no specific design changes have been identified that would allow the unit to increase efficiency without potentially compromising the operation of downstream equipment, there are no known changes to evaluate, and no heat rate improvement is anticipated to be associated with an economizer redesign/replacement project.

e) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

It is technically feasible to replace an economizer either with like-kind design or with some improvements in materials or heat transfer characteristics. Limited like-kind replacements of economizer sections have been made to repair tube damage with no impact to the heat rate of the unit. However, making changes to the economizer design or replacing the economizer in its entirety would have significant impacts on downstream equipment at this unit, including the SCR catalyst and the air heaters, which are sensitive to flue gas temperature changes. The existing economizer is functioning well in its current cycle and condition and does not warrant replacement.

7) <u>Heat Rate Improvement Practices</u>:

a) Do the staff at the plant where the unit is located undergo routine training that would positively affect the heat rate of the unit or units? (Such training may include any training related to efficiency or any other training on practices that result in heat rate improvements.)

Heat rate improvement "awareness training" is suggested as a means of elevating awareness of specific heat rate improvement efficiency measures among the operations and maintenance staff at units including Turk Plant affected by the rule. In the response to ACE Rule comments, EPA recognized that the level of awareness at individual units could vary dramatically, and that states might simply take into consideration whether there are existing programs at specific units as part of the overall evaluation of the candidate technologies. Capital costs are anticipated to be minimal and the impact of implementing new or existing programs is difficult to estimate and expected to be widely variable.

As generating units across the country have joined regional transmission organizations and begun offering the output of their units into competitive generation markets, cost-effective operation of individual units has become increasingly important. AEP units in the west are dispatched as part of SPP (Southwest Power Pool) which has a robust day-ahead energy market. As a result, increasing attention has been focused on ways to improve efficiency and lower operating costs.

i. If so, describe the training program including frequency of training and practices taught.

AEP provides training, monitoring tools, and "best practice" sharing forums for its employees as a way to help plant operators and staff to improve their awareness and equip them with means to maintain efficient operations and identify further efficiency improvements. Some of these tools and practices include:

- Operator training
- HRI classes, focusing on plant system optimization, are held at the Generation unit simulator center in St. Albans, WV and periodically attended by SWEPCO / Flint Creek personnel
- An automated Monitoring & Diagnostics Center

- Equipment control systems capable of automatically responding to changing conditions
- Regular technology updates and reviews
- Participating in and contributing to AEP Operational Excellence Program for best practices, including maximizing performance and reducing heat rate
- Maintaining thermal performance models of the unit design cycle with equipment references

The degree to which individual unit operators, supervisors and engineers undergo various parts of this training depends upon their position and desire to further develop and take on additional responsibilities. Some positions such as a Control Center Operator (CCO) requires prior successful completion of the NUS Heat Rate course. The CCO is also responsible to monitor "controllable" heat rate monitor screens in the unit control room to aid in determining the most efficient unit operation conditions for Turk Plant.

ii. If not,

1. **Please provide to DEQ a plan for instituting such a program.**

   Not applicable since AEP already conducts such a program for Turk Plant operators.

2. **Quantify the annual costs of implementing a program.**

   Not available on a specific unit or plant basis as this is part of continual learning within the AEP System.

3. **Quantify the expected heat-rate impacts of implementing a program.**

   Existing programs and measures are currently being employed and improvements are reflected in the historic emissions data for this unit. The precise percentage in unknown. No quantifiable incremental increase in heat rate improvement is anticipated as a result of continuing the existing practices, which include regular technology reviews and updates.

b) EPA requires DEQ to consider an "on-site appraisal" of heat-rate improvement opportunities at a specific unit. Please submit a report detailing the results of an onsite appraisal of heat-rate improvement opportunities. This appraisal may be conducted by an internal group or a third-party. Include a summary of the most recent inspection and recommendations for equipment maintenance or replacement to minimize heat-rate deviations, and include actions taken in response to the recommendations.

The practices identified in the prior section are tools used to assist unit operators and engineering support personnel on the AEP system in planning regular maintenance, developing the scope of work for planned outages, and designing monitoring or information collection efforts tied to specific equipment issues or unit liabilities. This can in turn allow internal personnel or third parties to be engaged to perform a more in-depth evaluation and assessment of specific ideas for improved heat rate performance. Such "appraisals" can be conducted to address issues identified on individual units, or to develop a more comprehensive effort that could be implemented at multiple units with a strategic alignment. Several ideas in the past were identified as potential heat rate improvements and collaboratively reviewed between plant staff, M&D Center analysts, AEP Engineering and in some cases an equipment OEM. These performance "enhancements" were developed with the intent of lowering pressure drop or stopping undesirable steam leakage flow as a means to improve performance and lower heat rate. Power plant personnel and engineers continually review the performance of various pieces of equipment to look for opportunities to make improvements, solicit necessary funding and outage time, and procure the necessary materials to implement the improvement. Many of these improvements are small and hard to measure individually or at the specific time of change, but continually aid in allowing the unit to perform as efficiently as possible. Current internal efforts are focused on optimizing unit operations at partial loads, or during sustained periods of low-load operation as being dictated by the SPP-controlled marketplace.

c) Does your plant have a routine steam surface condenser cleaning program?

Improved steam surface condenser tube cleaning was selected as a HRI measure that forms part of the BSER by EPA because the efficiency with which steam is condensed back into liquid is a critical part of the thermodynamic cycle. Lowering the temperature in the condenser and having an effective air removal system in operation decreases backpressure on the turbine allowing more efficient expansion in the steam cycle.

Turk Unit 1 main condenser undergoes an annual inspection and cleaning of the tubes each spring. The steam side of the tubes are inspected via physically entering the condenser steam compartment and looking at tube cleanliness and removing any debris. The water side condition of the condenser tubes are inspected during maintenance outages and cleaning processes applied as dictated by condition and thermal performance.

i. If so, describe the impact that this program has on the heat rate of each unit.

Condenser fouling has not typically been a problem on Turk Unit 1. Performance as indicated by the relationship between cooling water temperature and back pressure achieved during seasonal periods has tracked close to design. It is apparent that the cleaning methods are working and the quality of the cooling water and steam purity in the condensate cycle are being managed at optimum values.

ii. If not,

1. **Please provide to DEQ a plan for instituting such a program.**

   Not applicable

2. **Quantify the annual costs of implementing a program**.

3. **Quantify the expected heat-rate impacts of implementing a program.**

d) Please provide a detailed explanation if a practice is not technically feasible or limited due to the unique characteristics of the unit.

Not applicable

e) Please provide any other information relevant to the State's analysis of these practices.

Continuous monitoring of condenser performance for Turk Unit 1 indicates that control parameters regarding water quality and tube pluggage ratio are within acceptable limits. The condensers are performing well throughout the load range and under a variety of seasonal temperature conditions. Thus there is no basis to consider any changes regarding condenser cleaning procedures for this unit.

8) Gross vs net generation standards

a) Would you recommend the standards of performance for each affected unit be established in pounds of carbon dioxide emitted per net megawatt hour or per gross megawatt hour? Explain your recommendation.

The performance standard should be based on gross generation as this is the total generation produced by the unit, and is currently regularly monitored and reported through the Clean Air Markets Division for all units.

b) If your recommendation is for a gross generation-based standard, then do you have any recommendations for accounting for emissions reductions attributable to technologies affecting only net efficiency?

Technologies that impact net efficiency can be transient (impacting only certain load ranges or operating conditions) and difficult to measure. Gross measurements will assure that all conditions and load ranges are adequately measured and reported and there is no requirement to separately account for potential improvements in net efficiency.

Response of Southwestern Electric Power Company
to the Arkansas Department of Energy & Environment
Division of Environmental Quality
Information Request Regarding Candidate Technologies
For Flint Creek Unit 1

1) <u>Neural Network/Intelligent Sootblower System Information</u>:

a) Please indicate whether each unit listed above is tied in to a neural network system to optimize the unit's operations and minimize emissions.

Flint Creek Unit 1 does not utilize a neural network system for combustion optimization or any other operational system. Flint Creek Unit 1 utilizes a Distributed Control System (DCS) and Process Information (PI) monitoring systems to provide the unit operators with a full view of the critical operating conditions on the unit. Sensors monitor temperatures, pressures, heat rate deviations on certain subsystems, various alarms, and certain market-based conditions. In addition to optimizing steady state operations, these sensors and related controls allow unit operators to make necessary changes in real time when the unit is required to change loads in response to automatic generator control by the regional transmission operator.

There is also a centralized Monitoring and Diagnostic Center (MDC) available to the AEP system units, which has the capability to monitor and trend individual data points remotely in real time, spot early trends, and proactively recommend actions to improve performance or eliminate a curtailment before costly damage occurs. Based on the information available through these systems, operators are able to distinguish between controllable and uncontrollable factors impacting heat rate on the unit, and take prescribed actions to reduce the impacts associated with controllable factors as much as physically and economically possible. Intensive operator training, including the use of a centralized control system generator simulator during that training, provides our personnel with the knowledge necessary to initiate appropriate changes in operating parameters, and monitor the effects of automated responses in certain supplemental control systems, to assure that stability is achieved and maintained during all operating conditions.

i. If a unit is tied in to a neural network system,

1. When was the neural network first operated?

Not applicable

2. What impact did this have on your heat rate?

Not applicable

ii. If a unit is not tied in to a neural network system and the technology is feasible,

1. Please quantify the cost to implement a neural network system for your unit.

As described above, there are presently sophisticated control systems, instrumentation and monitoring resources available to maintain stable and efficient control of the combustion process and other unit operations without the use of “neural network” technology. While it would be feasible and expensive to install additional sensors, optimizers and control systems which are available on the market today, the degree of improvement that could be achieved through this investment is not expected to achieve the levels identified in Table 1 of the ACE Rule. Flint Creek Plant has not solicited any specific pricing for such a system, but has no reason to believe the cost would be significantly different that that listed in Table 2 of the ACE Rule.

2. Please quantify the expected heat-rate impact of implementation of a neural network system.

The opportunity for heat rate improvements with this technology is measured as a reduction of the typical heat rate increase that occurs over a long period of operating time. It is not an improvement in the design heat rate of the unit. In addition, the sensors, information, and controls must also be accompanied by actions necessary to make meaningful change in performance. While a neural network can expand the data points that are measured and monitored, it ultimately requires actions by both programmed control systems and experienced operators to start/stop and verify equipment operation or modify control settings to make meaningful change in performance. Since much of this work is already being achieved on Flint Creek Unit 1 through existing sensors and controls and experienced operators, it is expected that addition of a neural network would result in a marginal improvement that is less than the range predicted in Table 1 of the ACE Rule.

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Although technically feasible, the benefits of applying of this technology are limited for the reasons discussed above.

b) Is an intelligent soot blower system operated for any of the units listed above?

Flint Creek Unit 1 is equipped with an intelligent sootblowing system that was installed in 2007. The system that was installed is a product of Diamond Power Company.

i. If an intelligent soot blower system is operated for the unit, then please respond to the following questions:

1. Is the intelligent soot blower system incorporated into the neural network software? If so, does the impact you specified for l)a)i.2. include the impact of the intelligent soot blower system?

No, this unit does not use a neural network for combustion or sootblower control. The sootblowers have the ability to be automatically controlled via the supplied control system or via manual override by unit operators as may be needed.

2. If the intelligent soot blower system is not incorporated into a neural network software package, the please respond to the following:

a. **When was the intelligent soot blower system first operated?**

Water lances were installed prior to 2007 to improve cleaning of the radiant heat area of the furnace. The intelligent sootblower system was installed and put into service in 2007 during a scheduled unit outage. Then in 2016 the system was upgraded to a Diamond Power Sentry Series sootblowing system which included variable steam flow capability and several additional steam sootblowers.

b. **What impact did this have on your heat rate?**

Performance measurements to determine the impact of the sootblower systems on unit heat rate were not taken. These systems were installed primarily to reduce the risk of slag formation and potential unacceptable accumulation of ash on the heat transfer surfaces. Any heat rate "improvement" that is realized from these systems is in effect a reduction of the heat rate penalty being experienced against the unit design because of ash/slag buildup. These do not effectively improve the heat rate beyond the original design basis for a "clean" boiler, but when used effectively can maintain heat rate closer to the design value for a longer period of time.

ii. If an intelligent soot blower system is not operated for the unit and is technically feasible, then please respond to the following:

1. Please quantify the cost to install an intelligent soot blower for your unit.

Not Applicable

2. Please quantify the expected heat rate impact of the intelligent soot blower system.

Not Applicable

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Not Applicable.

c) **Please provide any other information relevant to DEQ's analysis of this candidate technology.**

Neural Network (NN) technology was developed and applied on a "test" basis to some steam generator equipment at other AEP units a decade ago. Reported results of the very controlled tests were highly variable and the technology focused on mainly one aspect (fuel-air distribution within the furnace) of the steam generation process. Testers concluded that the technology did not provide sufficient economic benefit to apply at full scale. Since that time, the implementation of the Mercury and Air Toxics Standards (MATS) rule has introduced increased regularity into the inspection, repair, and tuning of combustion controls. In addition, NN technology still requires manual coordination of several other processes, including starting and stopping large equipment such as pulverizers and fans, in order to maintain combustion stability within the steam generator. SWEPCO relies on well-trained and highly knowledgeable operators to perform this integrated control in a highly efficient and reliable manner without the use of NN's. The current use of the sootblowing system on Flint Creek Unit 1 maintains a high level of steam generator cleanliness and no measureable additive heat rate improvement is anticipated to result from integrating a neural network for this unit.

2**)Boiler Feed Pumps:**

Large electric motor powered boiler feed pumps (BFPs) supply feedwater to the steam generator in some units, and are responsible for a large portion of the auxiliary power consumed within a power plant (up to 10 MW from a 500 MW unit). Rigorous maintenance is required to ensure reliability and efficiency are maintained. Wear reduces the efficiency of the pump operations and requires regular rebuilds/upgrades/overhauls. These improvements for electric boiler feedwater pumps reduce auxiliary power demands and improve *net* heat rate, but would not result in measureable improvements in *gross* heat rate.

At Flint Creek Unit 1 the main boiler feed pump is driven by a steam turbine and not by an electric motor. As such, for most of the operating range of Unit 1 (above 24% output), the boiler feed pump is self-regulating and matches the steam needed to the load at which the unit is operating. In addition, it enhances the overall efficiency of the unit because of the reduced auxiliary electric demand (a reduction of as much as 35% of typical auxiliary load). For startup and low load operation, where there is insufficient steam yet available to supply the auxiliary drive steam turbine, a smaller motor-driven feed pump is used to provide the required feedwater. This pump is initially used during unit startup prior to the electric generator producing any output and is removed from service at approximately 24% load. Boiler feed pump turbines can experience degradation and wear over time, and require periodic maintenance to repair turbine blades, exchange rotors, and restore steam seals. At Flint Creek Unit 1, a regular turbine overhaul is planned approximately every 10 years, or after 80,000-100,000 hours of service. Given that the original design of this unit includes a more efficient technology for use above startup flow conditions, and the operator has adopted a regular schedule for overhauls of the pump and turbine, it is reasonable to conclude that no incremental improvement is currently achievable.

a) Over the past year, how does the performance of the boiler feed pumps for each unit compare to the manufacturer specifications?

The pump design is highly efficient and robust to withstand the rigor of numerous years of continued service with very little O&M required. The pump also maintains its efficient performance for the duration of the period between overhauls. During the past year, the feed pump has performed within the design specifications.

b) When was the last time the boiler feed pump(s) for each unit was overhauled or upgraded?

The main turbine-driven boiler feed pump was last overhauled and rebuilt in 2016. The startup motor-driven feed pump was last overhauled in 2017.

c) If the boiler feed pumps have not been overhauled or upgraded in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to overhaul or upgrade the boiler feed pump(s) for your unit.

Not applicable. The last overhauls were within specifications and within the performance period.

ii. Please quantify the expected heat rate impact of overhauling or upgrading the boiler feed pump(s).

Not applicable. Maintenance overhauls are performed on the feed pumps in order to maintain their capacity to perform reliably and uninterrupted during the operating periods. Any degradation is unlikely to achieve the amount that is projected within Table 1 of the ACE Rule. The internal condition of the pump must be maintained within manufacturer's specification in order to avoid operational failure and a forced outage.

iii. Please provide any other information relevant to the DEQ's analysis of this candidate technology.

Subcritical units using a single 1x100% capacity pump are not commonplace in the industry and thus the OEMs do not offer much in the way of efficiency improvements. AEP is not aware of any advanced designs for a steam-driven or electric motor driven boiler feed pump that could provide a heat rate improvement of 0.2%-0.5% above this unit's current performance as set forth in Table 1 of the ACE Rule.

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

The boiler feed pumps at this unit have been regularly maintained in accordance with manufacturer's specifications and additional overhauls are unnecessary.

3) <u>Please specify whether the air pre-heater for each unit listed above is regenerative (rotary) or recuperative (tubular or plate)</u>.

The two (2) air pre-heaters installed on Flint Creek Unit 1 are tri-sector regenerative air heaters which do rotate.

a) If your unit has a regenerative air pre-heater, when were the seals last replaced?

The air heater seals were last replaced as a complete set in 2005 during a scheduled outage. Seals are inspected and maintained on an annual basis during maintenance outages as recommended by the air heater OEM. This maintenance can include repairs to sealing components or replacement of partial sets of seals as necessary, based on damage or wear.

b) If the seals have not been replaced in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to replace the seals for the regenerative air pre-heater for your unit

As discussed above, the seals are inspected and maintained in accordance with the manufacturer's recommendations during regular outages. The costs for these inspections and repairs have not been separately tracked.

ii. Please quantify the expected heat-rate impact of from replacing the seals.

The impact is very marginal since only partial set repairs or replacement are typically necessary due to extent of damage or wear. Continued replacements in accordance with past practice will allow the unit to maintain its historic efficiency.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

The improvement projected from this technique (upgraded air heater seals) results from limiting air in-leakage on regenerative air heaters by replacing air heater seals with newer designed low-leakage seals. Most units have some rate of air in-leakage, which can result in higher demand on the fans that provide air to the combustion zone in the boiler and higher auxiliary power demands.

For this unit, air heater seals are typically inspected, repaired or replaced with in-kind seals during equipment outages when the air heater baskets are replaced or when seals are found damaged. Additionally, the air heater internal ducts and sector plates are inspected during maintenance on the air heater, and localized repairs and stationary seal replacements can be made during those inspections if materials are available, or included in future outage plans.

There are products on the market that advertise lowering the amount of leakage experienced within air pre-heater equipment. While it is likely feasible to install such products on Flint Creek Unit 1, it is currently AEP's opinion that the newer designs for low-leakage seals present risks to unit reliability and air heater functionality that may outweigh any efficiency gains. A thorough technical review is needed to determine applicability and potential benefits for Flint Creek Unit 1. Plant operators currently use PI system screens for monitoring differential pressure, temperatures and flue gas pressure in the air heater and motor amps for the PA, FD and ID fans in order to assess air heater loading and performance. Application of the low-leakage seal design would require some level of detailed engineering and design by the boiler and/or air heater OEM(s) to determine a suitable method of application and to determine the potential benefits to be gained and reliability risks to consider in each specific case. A feasibility study has not been performed for this unit. Some leakage at this location is necessary to avoid air heaters "locking up" (not being able to rotate) which can lead to malfunctions, curtailments, or availability problems.

d) Please provide a detailed explanation if the technology or practice is not technically feasible or limited due to the unique characteristics of the unit.

See response to item c) above.

4) <u>Variable Frequency Drives (VFD) information for each listed unit:</u>

Variable Frequency Drives are available that work in concert with traditional electric motors to vary the speed necessary during unit load changes to maximize performance of the driven equipment and reduce losses. This results in a reduction of power consumption as an auxiliary load and helps to maximize the net electrical generation from the unit. The most effective applications are for electric driven boiler feed pumps that control feed water flow and induced draft fans that control air/gas flow through the flue gas path.

At Flint Creek Unit 1, approximately 50 - 60 percent of the electric demand on a typical unit has already been addressed, including both of the major applications for VFDs identified in the ACE rule. First, the main BFP is driven by an auxiliary steam turbine that automatically adjusts to the required load and does not consume electricity. This pump/turbine combination is placed in service when the unit advances off of the startup system and achieves approximately 24% output and remains in service up through full load. Second, induced draft fans were last replaced on the unit in 2016 and are axial flow fans with variable blade vane pitch, which reduce energy losses, enhance operator control, and increase volumetric flow through the unit to increase efficiency. The axial vane fans deliver substantially similar benefits as VFDs. In fact, in its 2009 report on coal-fired power plant heat rate reductions, Sargent & Lundy compared the benefits of centrifugal fans with VFDs to axial vane fans, and determined that the axial vane fans provided slightly superior performance. *Coal-Fired Power Plant Heat Rate Reductions*, Sargent & Lundy, Final Report on Project 12301-001 (Jan. 22, 2009) at p.8-5.

a) **Does your unit have VFD controls for the induced draft (ID) fans**?

No

i. If so,

1. When was the VFD first operated?

Not Applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not Applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the ID fans for your unit.

As mentioned in the paragraph above, Flint Creek Unit 1 was able to install axial vane variable flow fans for the induced draft fan applications when the FGD equipment was installed in 2016. SWEPCO does not have a true cost for adding a VFD onto an existing induced draft centrifugal fan. The axial vane fans were part of the larger FGD equipment project installed in 2016. Power differential to operate the axial vane fans versus a conventional centrifugal fan and motor with VFD is negligible.

2. Please quantify the expected heat-rate impact of the installation and operation of VFD for ID fans for both base-load and cycling operating scenarios.

Based on the Sargent & Lundy report, SWEPCO anticipates that any difference would be negligible.

b) **Does your unit have VFD controls for the boiler feed pumps?**

No. As mentioned in Question 2 (Boiler Feed Pumps) above, the single main boiler feed pump is driven by a steam turbine. The auxiliary startup boiler feed pump is driven by an electric motor.

i. If so,

1. When was the VFD first operated?

Not applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the boiler

feed pump(s) for your unit.

Application of a VFD to the auxiliary boiler feed pump drive motor would likely be cost prohibitive since the motor is approximately 5,000 HP, operates for a limited time only during startup when feed water flow is low and controlled by a regulating valve and the electric generator is not yet connected to the grid (producing 0 MWs). Occasionally the auxiliary feed pump may be brought into service during unit load reduction with the generator producing low MWs for shorts periods of time (hours) to perform troubleshooting or testing of the main BFP or drive turbine. This period would likely not be part of the emissions performance standard period of testing.

2. Please quantify the expected heat rate impact of the installation and operation of VFD for the boiler feed pump(s) for both base-load and cycling operating scenarios.

The impact of adopting a VFD to the auxiliary boiler feed pump motor would be extremely low, well below the suggested range offered in ACE Rule Table 1, as this motor is infrequently used and likely produce unmeasurable benefits.

iii. Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there is no electrical load consumed by the boiler feed pump over the majority of this unit's operating range (all loads above 24%), the design of the axial vane fans provide similar efficiency benefits, and the small motor used during start up operates only at low loads and infrequently, any benefits from applying VFDs would be well outside the range estimated by EPA and would not be cost-justified.

c) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

See response to item b)iii., above.

5) <u>Blade Path Upgrade (Steam Turbine) for each listed unit:</u>

The best candidates for blade path upgrades are those turbines experiencing steam leaks and blade erosion, where efficiency improvements can be achieved using computerized flow modeling and innovative materials. However, there is significant variation among units. These upgrades are large capital investments and require long lead times.

Flint Creek Unit 1 is equipped with one combined and opposed-flow high pressure/reheat turbine and two low pressure turbines. This unit is unique on the AEP system. No spare turbine rotors exist so all components are either repaired or replaced if necessary during maintenance inspections.

a) Has the steam turbine for the unit been upgraded or overhauled in the past ten years? If so,

i. When was the turbine upgraded or overhauled?

The steam turbine on Flint Creek Unit 1 has not been upgraded in the last 10 years. The steam turbine has been overhauled during the last 10 years. Steam turbine sections (HP/RH, LP1, LP2) were all overhauled last in 2018.

ii. Describe how the turbine was upgraded or overhauled.

During the 2018 unit maintenance outage, the turbines were overhauled by opening and assessing condition, cleaning and removal of blade deposits, inspection and non-destructive testing of components, repairing or replacement of worn or damaged blades with like-kind materials and restoration of seals to design clearance values. Specifically, inlet row rotating blades were replaced with new in the HP turbine (Row 1) and RH turbine (Row 8). Closing clearances were recorded and the turbine casings reassembled. Rotor vibration levels are monitored during startup to determine no rubs occur and rotor balance is acceptable. Steam pressures and temperatures are measured to confirm proper steam expansion is taking place.

iii. How did the upgrade or overhaul impact the unit's heat rate?

As a result of the turbine overhaul, most of the “recoverable” losses that occur during the normal operating cycle of the steam turbine sections were reduced and overall performance moved closer to design values. A formal heat rate test utilizing highly calibrated test instruments is not typically performed following a turbine overhaul as this is not cost effective. Improvement is typically measured with installed station instrumentation by a reduction in feedwater flow and steam generator heat input for a given MW production as corrected to standard throttle conditions.

iv. Are there further upgrades available that would improve the efficiency of the turbine?

Yes, there are steam path upgrades that have been applied to similar units. Typically a steam path upgrade is only cost-justified if other changes to a unit will significantly increase auxiliary loads, and some of those losses can be offset by the turbine upgrade. The novel scrubber design used at Flint Creek Unit 1 does not increase auxiliary power demands as much as conventional wet or dry scrubbers, so the investment was not justified when those controls were installed. Currently, demand for electricity is not growing at a rapid pace, and other alternatives for additional generating capacity can be more economically attractive than increasing the output of a coal-fired unit. An economic evaluation for any potential steam path upgrade is recommended. These factors, and the potential to trigger NSR review, would need to be carefully considered in addition to whether a turbine upgrade would fall within the range of the ACE Rule Table 1 estimates as well as the Table 2 range for HR improvement.

b) If not,

i. Please quantify the cost to upgrade or overhaul the steam turbine for your unit. (You may factor the costs associated with new source review, if it would be triggered by the upgrade, into your cost calculations.)

The cost of a turbine overhaul or upgrade can vary significantly based on the amount of damage to or degradation of existing components (for an overhaul), or the extent of any design changes associated with an upgrade. . Some upgrades may require replacement of turbine rotors, blade carriers and casings in addition to the blades, at a substantially increased cost and scope of work. No specific upgrades have been designed or estimated for the turbines at Flint Creek Unit 1.

ii. Please quantify the expected heat rate impact of upgrading or overhauling the steam turbine.

Regular overhauls restore and maintain the efficiency of the unit. No specific upgrade designs have been developed for Flint Creek Unit 1 and therefore the heat rate impact cannot be estimated.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Steam turbine overhauls and steam path inspections/repairs have been performed at Flint Creek Unit 1 over the years to return the turbine to near design conditions. These were performed during scheduled outages when turbine inspections have allowed for any liabilities to be addressed and for replacement parts to be procured and made ready for installation. Current upgrade offerings that may be available for the turbine sections have not been deemed cost-effective. The next regular maintenance opportunity for this turbine is not until 2028 at the earliest.

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

Please see the responses to items b) and c), above.

6) <u>Economizer for each listed unit</u>

Replacing or redesigning the economizer can optimize temperatures at the exit of the boiler. Boiler layout and construction may limit the applicability of this measure to certain units.

a) When was the economizer last replaced?

The economizer on Flint Creek Unit 1 is original and has never been replaced. On occasion, there has been a need to locate and access certain areas of the economizer to address leaking tubes or other physical damage. This repair could result in replacement of a small number of tubes or partial tube sections but no major replacement of tube bundles has been necessary.

b) Throughout the past year, how does the performance of the economizer for each unit compare to the manufacturer specifications for a new unit?

During the past year, the economizer on Flint Creek Unit 1 has performed well, allowing for critical temperatures such as boiler exit gas and air heater gas outlet temperatures to remain within manufacturer specifications throughout the load range.

c) If the performance of the economizer for a unit has degraded outside the performance range of the manufacturer's specifications:

i. Please quantify the cost to redesign/replace the economizer for your unit.

Not applicable

ii. Please quantify the expected heat-rate impact of redesigning/replacing the economizer.

Not applicable

d) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there are currently no issues with the performance of the existing economizer, and no specific design changes have been identified that would allow the unit to increase efficiency without potentially compromising the operation of downstream equipment, there are no known changes to evaluate, and no heat rate improvement is anticipated to be associated with an economizer redesign/replacement project.

e) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

It is technically feasible to replace an economizer either with like-kind design or with some improvements in materials or heat transfer characteristics. Limited like-kind replacements of economizer sections have been made to repair tube damage with no impact to the heat rate of the unit. However, making changes to the economizer design or replacing the economizer in its entirety would have significant impacts on downstream equipment at this unit, including the air heaters, which are sensitive to flue gas temperature changes. The existing economizer is functioning well in its current cycle and condition and does not warrant replacement.

7) <u>Heat Rate Improvement Practices</u>:

a) Do the staff at the plant where the unit is located undergo routine training that would positively affect the heat rate of the unit or units? (Such training may include any training related to efficiency or any other training on practices that result in heat rate improvements.)

Heat rate improvement "awareness training" is suggested as a means of elevating awareness of specific heat rate improvement efficiency measures among the operations and maintenance staff at units including Flint Creek Plant affected by the rule. In the response to ACE Rule comments, EPA recognized that the level of awareness at individual units could vary dramatically, and that states might simply take into consideration whether there are existing programs at specific units as part of the overall evaluation of the candidate technologies. Capital costs are anticipated to be minimal and the impact of implementing new or existing programs is difficult to estimate and expected to be widely variable.

As generating units across the country have joined regional transmission organizations and begun offering the output of their units into competitive generation markets, cost-effective operation of individual units has become increasingly important. AEP units in the west are dispatched as part of SPP (Southwest Power Pool) which has a robust day-ahead energy market. As a result, increasing attention has been focused on ways to improve efficiency and lower operating costs.

i. If so, describe the training program including frequency of training and practices taught.

AEP provides training, monitoring tools, and "best practice" sharing forums for its employees as a way to help plant operators and staff to improve their awareness and equip them with means to maintain efficient operations and identify further efficiency improvements. Some of these tools and practices include:

- Operator training
- HRI classes, focusing on plant system optimization, are held at the Generation unit simulator center in St. Albans, WV and periodically attended by SWEPCO / Flint Creek personnel
- An automated Monitoring & Diagnostics Center
- Equipment control systems capable of automatically responding to changing conditions
- Regular technology updates and reviews
- Participating in and contributing to AEP Operational Excellence Program for best practices, including maximizing performance and reducing heat rate
- Maintaining thermal performance models of the unit design cycle with equipment references

The degree to which individual unit operators, supervisors and engineers undergo various parts of this training depends upon their position and desire to further develop and take on additional responsibilities. Some positions such as a Control Center Operator (CCO) requires prior successful completion of the NUS Heat Rate course. The CCO is also responsible to monitor "controllable" heat rate monitor screens in the unit control room to aid in determining the most efficient unit operation conditions for Flint Creek Plant.

ii. If not,

1. **Please provide to DEQ a plan for instituting such a program.**

   Not applicable since AEP already conducts such a program for Flint Creek operators.

2. **Quantify the annual costs of implementing a program.**

   Not available on a specific unit or plant basis as this is part of continual learning within the AEP System.

3. **Quantify the expected heat-rate impacts of implementing a program.**

   Existing programs and measures are currently being employed and improvements are reflected in the historic emissions data for this unit. The precise percentage in unknown. No quantifiable incremental increase in heat rate improvement is anticipated as a result of continuing the existing practices, which include regular technology reviews and updates.

b) **EPA requires DEQ to consider an "on-site appraisal" of heat-rate improvement opportunities at a specific unit. Please submit a report detailing the results of an onsite appraisal of heat-rate improvement opportunities. This appraisal may be conducted by an internal group or a third-party. Include a summary of the most recent inspection and recommendations for equipment maintenance or replacement to minimize heat-rate deviations, and include actions taken in response to the recommendations**.

The practices identified in the prior section are tools used to assist unit operators and engineering support personnel on the AEP system in planning regular maintenance, developing the scope of work for planned outages, and designing monitoring or information collection efforts tied to specific equipment issues or unit liabilities. This can in turn allow internal personnel or third parties to be engaged to perform a more in-depth evaluation and assessment of specific ideas for improved heat rate performance. Such "appraisals" can be conducted to address issues identified on individual units, or to develop a more comprehensive effort that could be implemented at multiple units with a strategic alignment. Several ideas in the past were identified as potential heat rate improvements and collaboratively reviewed between plant staff, M&D Center analysts, AEP Engineering and in some cases an equipment OEM. These performance "enhancements" were developed with the intent of lowering pressure drop or stopping undesirable steam leakage flow as a means to improve performance and lower heat rate. Power plant personnel and engineers continually review the performance of various pieces of equipment to look for opportunities to make improvements, solicit necessary funding and outage time, and procure the necessary materials to implement the improvement. Many of these improvements are small and hard to measure individually or at the specific time of change, but continually aid in allowing the unit to perform as efficiently as possible. An example of these types of efforts include AEP's engagement of internal engineering resources or third party computerized flow modeling expertise to address optimization of low NOx burner combustion and over-fire air controls. Current internal efforts are focused on optimizing unit operations at partial loads, or during sustained periods of low-load operation as being dictated by the SPP-controlled marketplace.

c) Does your plant have a routine steam surface condenser cleaning program?

Improved steam surface condenser tube cleaning was selected as a HRI measure that forms part of the BSER by EPA because the efficiency with which steam is condensed back into liquid is a critical part of the thermodynamic cycle. Lowering the temperature in the condenser and having an effective air removal system in operation decreases backpressure on the turbine allowing more efficient expansion in the steam cycle.

Flint Creek Unit 1 main condenser undergoes an annual inspection and cleaning of the tubes each spring. The steam side of the tubes are inspected via physically entering the condenser steam compartment and looking at tube cleanliness and removing any debris. The water side of the condenser tubes are cleaned continually through the use of a system which circulates cleaning balls randomly through the condenser tubes while the unit is in service to prevent deposition on the tubes.

i. If so, describe the impact that this program has on the heat rate of each unit.

Condenser fouling has not typically been a problem on Flint Creek Unit 1. Performance as indicated by the relationship between cooling water temperature and back pressure achieved during seasonal periods has tracked close to design. It is apparent that the cleaning methods are working and the quality of the cooling water and steam purity in the condensate cycle are being managed at optimum values.

ii. If not,

1. **Please provide to DEQ a plan for instituting such a program.**

   Not applicable

2. **Quantify the annual costs of implementing a program**.

3. **Quantify the expected heat-rate impacts of implementing a program.**

d) **Please provide a detailed explanation if a practice is not technically feasible or limited due to the unique characteristics of the unit.**

Not applicable

e) **Please provide any other information relevant to the State's analysis of these practices.**

Continuous monitoring of condenser performance for Flint Creek Unit 1 indicates that control parameters regarding water quality and tube pluggage ratio are within acceptable limits. The condensers are performing well throughout the load range and under a variety of seasonal temperature conditions. Thus there is no basis to consider any changes regarding condenser cleaning procedures for this unit.

8) Gross vs net generation standards

a) Would you recommend the standards of performance for each affected unit be established in pounds of carbon dioxide emitted per net megawatt hour or per gross megawatt hour? Explain your recommendation.

The performance standard should be based on gross generation as this is the total generation produced by the unit, and is currently regularly monitored and reported through the Clean Air Markets Division for all units.

b) If your recommendation is for a gross generation-based standard, then do you have any recommendations for accounting for emissions reductions attributable to technologies affecting only net efficiency?

Technologies that impact net efficiency can be transient (impacting only certain load ranges or operating conditions) and difficult to measure. Gross measurements will assure that all conditions and load ranges are adequately measured and reported and there is no requirement to separately account for potential improvements in net efficiency.