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AR-20-008

April 17, 2020

Mr. Will Montgomery
Associate Director
Office of Air Quality
Division of Environmental Quality
Arkansas Department of Energy and Environment
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Information Request Regarding Candidate Technologies for the Affordable Clean Energy (ACE) Rule

Dear Mr. Montgomery:

This letter responds to the Information Request that ADEQ sent to Entergy on November 19, 2019, regarding an evaluation of candidate heat rate improvement technologies for the coal-fired units at the White Bluff and Independence Stations ("Information Request"). In the Information Request, ADEQ asked questions related to the following candidate heat rate improvement technologies:

1. Neural network/intelligent sootblower systems
2. Boiler feed pumps
3. Air preheaters
4. Variable frequency drives (VFD) on ID fans and boiler feed pumps
5. Steam turbine blade path upgrades
6. Economizers
7. Heat rate improvement technologies

Responses to the questions in the Information Request about each of the candidate heat rate improvement technologies have been provided in the attached reports: *Arkansas Department of Environmental Quality (DEQ) Affordable Clean Energy (ACE) Analysis for Independence Station Response to Agency Questions* (April 17, 2020) ("Independence Report"), and *Arkansas Department of Environmental Quality (DEQ) Affordable Clean Energy (ACE) Analysis for White Bluff Station Response to Agency Questions* (April 17, 2020) ("White Bluff Report").

The Information Request's final question asks the following questions with respect to gross v. 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.*
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?*

Entergy has reviewed potential issues associated with applying net and gross heat rate to the performance standard. Based upon its review, Entergy's preferred approach is that the standards of performance for each affected unit be established as a gross generation standard. It is important that heat rate improvement measures identified as candidate technologies are consistent with the proposed performance standard.

An initial reason for recommending a performance standard on a gross basis is the availability of data. Entergy expects that most state agencies will rely on publicly available emissions data reported by generators to establish baseline $CO_2$ emissions. The most comprehensive emissions dataset is EPA's Air Markets Data Program (AMPD). AMPD emissions data has been used to inform other regulatory programs including the Regional Haze Rule and Cross State Air Pollution Rule (CSAPR). The AMPD dataset includes $CO_2$ emissions and load data reported on a gross basis which can be used to establish baseline $CO_2$ emissions and baseline heat rate. If baseline emissions are measured on a gross basis, heat rate improvements and the corresponding performance standard also should be established on a gross output basis (i.e. lb. $CO_2$/MW-g). Furthermore, to establish consistent and comparative baseline emission rates and heat rates within the statewide fleet, it is practical for the State to use publicly available AMPD gross load data.

If performance standards were to be established on a net load basis (lb/MW-n), not only would a significant amount of historic net generation data need to be collected but, in the future, additional data would need to be reported to AMPD. This would require more onerous monitoring, equipment calibration, and reporting to demonstrate compliance.

In general, gross heat rate is an indicator of boiler efficiency and turbine performance. Based on the relationship of heat rate (Btu/kWh) and output (MW), the percent change in heat rate will be equivalent to the $CO_2$ emission rate change (reported as lb/MWh) as long as the same basis of gross or net is used for the calculation.

Gross plant heat rate (GPHR) is typically calculated as the net turbine heat rate (NTHR) divided by the boiler efficiency as follows:

GPHR = NTHR/Boiler Efficiency

NTHR relates to the efficiency of the turbine to convert steam from the boiler into usable rotational energy; unlike its name suggests, NTHR is not reflective of the *net power* generation from the unit. Net plant heat rate (NPRH) is a function of the NTHR and boiler efficiency, as well as the unit's auxiliary power requirements. NPHR can be calculated as follows:

NPHR = NTHR / [(1-Aux%) * Boiler Eff%]

Where: Aux% represents the auxiliary power requirement as a function of total unit capacity.

Given the parameters used to calculate GPHR and NPHR, it is important that the evaluation of heat rate improvement candidate technologies be consistent with the proposed performance standard. Candidate technologies that affect boiler efficiency or turbine efficiency would affect both gross and net plant heat rate. The candidate technologies that affect boiler efficiency or turbine efficiency include:

- Neural network/intelligent sootblowers
- Redesign or replacement of the economizer
- Air heater and duct leakage control
- Boiler feed pump (specifically for the Independence and White Bluff units, which have turbine driven pumps)
- Steam turbine blade path upgrades

Alternatively, candidate technologies that reduce auxiliary power will improve NPHR but will have no effect on GPHR. These include:

- VFD fans and pumps
- Air heater and duct leakage control

The two technologies that solely impact auxiliary power consumption typically have two of the lowest overall potential benefits to heat rate. In addition, VFDs have variable impact based on operating load and leakage control. Specifically, for the White Bluff and Independence units, there is no viable improvement identified from the implementation of either of these controls that would solely impact the net heat rate. As such, Entergy has not suggested measures for accounting for emissions reductions attributable to technologies affecting only net efficiency.

While the only differentiating factor between NPHR and GPHR is auxiliary power, that difference makes the calculation more complex. Turbine heat rate and boiler efficiency can be calculated based on defined ASME performance test codes (PTCs); PTC 4 is used for boiler efficiency and PTC 6 for turbine efficiency. These tests are accurate and repeatable, so long as the instruments used during the procedure are calibrated properly and the measured parameters are well defined. The accuracy and repeatability of the tests allow for a performance standard that is quantifiable and verifiable as required by 40 C.F.R. § 60.5755a(b).

Auxiliary power consumption must account for hundreds of consumers throughout the power plant. Numerous instruments and monitors would be needed to accurately track auxiliary power loads on a unit-specific basis. Rather than monitoring each individual load, total auxiliary power consumption is typically determined by subtracting power delivered to the grid from the gross power generated. However, this approach includes administrative services and other unaccounted services that consume power that is typically deducted just before the grid. More importantly, at generating stations with more than one unit, distribution of common loads may be attributed in a higher percentage to one unit versus the other, negatively impacting net heat rate for that unit. This could especially be detrimental to the calculation of $CO_2$ emission on a net output basis if a single unit is required to provide the entire common load while the remaining units are shut down.

Given the number of power consumers that require monitoring to determine NPHR on a unit-by-unit basis, some generating facilities measure net power output on a facility-wide basis and attribute a certain percentage of the auxiliary power consumption to each unit. These percentages are often attributed at a constant rate for the entire year and are not adjusted to account for changes in power consumption with load, season, or equipment degradation. Without implementing more rigorous monitoring of auxiliary power loads on a unit-specific basis, it would be difficult to verify compliance with a unit's standard of performance if it is based on net generation.

Another item to consider when reviewing net versus gross load standard, is the potential for future air quality control systems to maintain regulatory emissions limits. If a facility is required to implement additional controls past 2023, this may include a large increase in auxiliary power consumption after the performance standard has already been set. As more auxiliary power is consumed due to these technologies, the calculated $CO_2$ emission rate on a lb/MWh-n basis would increase and could even exceed the baseline rate. Ultimately, there would be a negative impact on $CO_2$ emissions compliance if future emissions control devices were implemented. This unjustly affects facilities that may need to implement additional controls in the future; however, there would be negligible impact to $CO_2$ compliance if the performance standards were set based on gross load.

In conclusion, Entergy recommends establishing performance standards on a gross load basis for the following reasons:

- Gross power output is currently measured and reported, which makes baseline emissions and baseline heat rates more easily and consistently estimated by the State;
- GPHR can be determined based on defined ASME performance test codes, which are accurate and repeatable. The accuracy and repeatability of the tests allow for a performance standard that is quantifiable and verifiable as required by 40 C.F.R. § 60.5755a(b);
- A majority of the candidate heat rate improvement technologies, including the technologies with the greatest potential for heat rate improvement, affect gross plant heat rate;
- There are only a few candidate technologies that improve auxiliary power consumption and, therefore, only impact net plant heat rate, and they have relatively minor changes to overall NPHR;

- Additional monitoring, equipment calibration, and reporting would be needed to demonstrate compliance with a performance standard based on net output;
- Auxiliary loads attributable to individual units are often not available, and total auxiliary loads at facilities with more than one unit may not be accurately attributed to each individual unit, which would negatively impact the net heat rate for individual units; and
- Gross power generation standards would not be negatively impacted by future implementation of additional emissions control technologies.

If you have any questions regarding this submittal, please contact me at (501) 377-4038 or Stan Chivers at (501) 377-4033.

Sincerely,

Russell McLaren

Russell McLaren
Manager, Arkansas Environmental Support

cc: Stan Chivers

# ARKANSAS DIVISION OF ENVIRONMENTAL QUALITY (DEQ)
# AFFORDABLE CLEAN ENERGY (ACE)
# ANALYSIS FOR INDEPENDENCE STATION

# RESPONSE TO AGENCY QUESTIONS

FINAL REV 0

April 17, 2020
Project No. 13603-002

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## Introduction

In January 2020, Sargent & Lundy LLC (S&L) conducted a heat rate review of the Independence Steam Electric Station (ISES) on behalf of Entergy. The review was conducted in response to an information request dated November 5, 2019 from the Arkansas Division of Environmental Quality (ADEQ) and included an assessment of potential heat rate improvement technologies that could be applied to ISES Units 1 and 2. S&L evaluated each technical alternative identified by ADEQ in the information request to determine whether they are technically feasible at ISES as a means of improving heat rate and thus reducing $CO_2$ emissions on a pound per megawatt-hour (lb/MWh) basis. The purpose of this report is to provide technical responses, prepared by S&L on behalf of Entergy, to specific questions in the November 5, 2019 information collection request.

### *Basis and Limitations*

Heat rate improvement technologies identified in ADEQ's information request were evaluated for each unit based on site-specific analyses. Site operating data was collected, previous studies were reviewed, and interviews with personnel were conducted to determine whether any of the candidate technologies had already been implemented and what actual heat rate improvements were realized, if any. Technically feasible and available technologies were evaluated at a conceptual level for both effectiveness (i.e., heat rate improvement) and costs. The review shows that it would not be feasible to apply all the examined alternatives to an individual generating unit due to several factors including plant design, previous equipment upgrades, and operational approaches. A more detailed evaluation of the technical feasibility, limitations, and potential heat rate improvement associated with each of the identified technologies is provided below.

### *Heat Rate vs. Load*

The heat rate for ISES Units 1 and 2, as with all coal-fired steam electric generating units, is closely linked to boiler operating load. Performance at full load is not representative of low load operation. While each unit can operate at gross loads up to approximately 880 MW-gross (MWg), since 2014, the facility has spent over 30% of its operating hours below 50% load.

Based on historic heat rate curves, the units operate at higher heat rates (i.e., less efficient) while operating at loads below approximately 500 MW. These higher heat rates occur when the boiler and steam turbine operate outside of full load or near-full load design conditions. As such, gross and net heat rates increase at lower load. This is also true for other equipment, including large fans and pumps, which has an additive effect on the net heat rate curve. Heat rates at lower loads can be as much as 30-40% higher than at full load. Based on historic and projected unit dispatch, it is projected that the facility will continue to operate for significant periods of time below 50% load, which will directly impact achievable heat rate and subsequent $CO_2$ emission rates. Furthermore, if future operation results in lower capacity factors than what is represented in the baseline period, then the facility will have difficulty demonstrating improvement for any of the heat rate measures evaluated below.

For this evaluation, potential heat rate improvements were evaluated at full load, unless noted otherwise. Further evaluation would be required to determine the potential of heat rate improvement for each technology at all operating load conditions. Historic operation has shown that the units spend a significant amount of time cycling, which will result in the unit spending more time operating at minimum load. As such, the impact of load on heat rate must be considered in the evaluation of the technical feasibility and effectiveness of available heat rate improvement technologies.

*Timeline Impacts*

Degradation of performance over time and seasonal impacts must be considered when evaluating heat rate improvement and developing compliance timeframes. The heat rate improvement measures evaluated herein may provide measurable improvement when first implemented; however, there is degradation that occurs over time that is expected and considered generally acceptable between major overhaul outages. As such, the heat rate improvement achievable with each technology will vary from year to year. In addition, the heat rate improvement attained with each technology may also vary from month to month due to variability in heat rate with seasonal temperatures and other ambient conditions. Seasonality and overhaul schedules must be considered in the evaluation of the technical feasibility and effectiveness of available heat rate improvement technologies, as well as baseline and future compliance time periods.

*New Source Review Compliance*

If it is determined that a heat rate improvement candidate technology is feasible, implementation of the technology must be evaluated for New Source Review (NSR) applicability. Potential NSR applicability has not been factored into the analysis of any of the heat rate improvement candidate technologies in this report. If installation of a heat rate improvement candidate technology would trigger applicability of the NSR requirements, it likely would increase the timeframe for installation due to the need to obtain a NSR permit as well as the costs of the heat rate improvement candidate technology if the installation of best available control technology ("BACT") were also necessary.

*Heat Rate Improvement Technology Costs*

The ADEQ requested facilities to utilize the Electric Power Research Institute (EPRI) Cost Manual Estimator or the EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating costs to implement the technical options.[1] However, the Control Cost Manual does not include a chapter on heat rate improvement candidate technologies rather, ADEQ references Chapter 2 of the manual, which identifies the concepts and methodology of cost estimation. Therefore, S&L utilized the approach described in the Control Cost Manual, to the extent practicable, to develop costs consistent with a study-level cost estimate. Cost estimates were developed for technically feasible options, based on unit-specific vendor budgetary quotes or historic pricing from comparable units. In addition, the EPA's Control Cost Manual was used to establish overall project costs.

*Remaining Useful Life of the Facility*

Entergy intends to cease coal-fired operations at the Independence units by December 31, 2030, as the ADEQ noted in its Phase 2 Regional Haze SIP. Entergy has entered into a proposed settlement agreement with Sierra Club and National Parks Conservation Association that is currently pending before the U.S. District Court for the Eastern District of Arkansas (*Sierra Club, et al. v. Entergy Arkansas, LLC, et al.*, No 4:18-cv-00854 -KGB (E.D. Ark.)). If the court approves the settlement, the cessation of coal-fired operation at the Independence units will become an enforceable commitment. As such, cost effectiveness calculations should consider this date when evaluating annualized capital costs.

[1] EPA Air Pollution Control Cost Manual, Seventh Edition, Chapter 2, November 2017.

**Candidate Heat Rate Improvement Technologies**

1. Neural Network/Intelligent Sootblower System

ISES Units 1 and 2 installed Schneider Electric's Connoisseur neural network systems and started operation in 2004. The neural network can continuously collect and interpret plant data to predict thermodynamics of the boiler. This computer analysis system is necessary to interpret large quantities of actual boiler data including combustion air flow, fuel flow, and temperature. ISES's neural network system is combustion optimization software that is set up to optimize both CO and NOx, for emissions control, with some functions for boiler optimization.

The facility could use neural network to modify boiler outlet $O_2$ to improve boiler efficiency; however, the facility has optimized the $O_2$ set point curve to keep the CO emissions within the permit limitation. As the system is being utilized to maintain CO emissions compliance, any modification to prioritize optimization of heat rate could result in exceedances of CO. Since the neural network was not operated to improve heat rate performance, there has been no notable impact on heat rate.

Full load furnace $O_2$ outlet over the last year is approximately 3.47% for Unit 1 and 3.24% for Unit 2, which is slightly higher than optimal; this translates into approximately 23% and 22% excess air for Unit 1 and Unit 2, respectively. Original boiler design was based on 86.38% at MCR with 20% excess air, which would be equivalent to approximately 3% $O_2$ at the furnace outlet. If the neural network system could be programmed to optimize $O_2$ to meet 3% at the furnace outlet, then the flue gas volumetric flow rate through the backend of the facility could be reduced by 2.5% on Unit 1 and 1.1% on Unit 2. This adjustment would result in a nominal decrease in fan power for the forced draft (FD) and induced draft (ID) fans, which could increase net power output by 0.01-0.03%, for Unit 2 and Unit 1, respectively. In addition, boiler efficiency would increase if excess air were dropped, resulting in less heat of combustion being used to heat combustion air. Overall, the excess air change from 2-3% may only provide 0.1% reduction in heat rate. However, it does not appear to be possible to reduce the boiler outlet $O_2$ without exceeding the facility CO permit limitation; station personnel already are diligent about optimizing $O_2$ as much as possible, while still meeting the CO emission limitations. As such, no further actions have been identified as feasible to improve the plant heat rate from neural networks. Therefore, no heat rate improvement can be quantified, and costs have not been developed.

ISES Units 1 and 2 are currently operating with Diamond Power intelligent sootblowers with Foxboro controls integrated into the neural network. The facility has installed the sootblowers as part of various projects, with the most recent project in 2014 which now provides essentially full coverage of the furnace and economizer. Many of the changes in the intelligent sootblowing system would have impacted boiler performance after the original installation of the neural network; however, these systems have different boiler performance goals. Like the neural network, it is not possible to quantify the impact of the intelligent sootblowers on the facility's heat rate, especially since the sootblowers were integrated over time.

The intelligent sootblowers were installed to systematically identify specific surfaces of the boiler that need to be cleaned based on monitored gas and steam conditions. By detecting specific boiler tubes that have slag built up, the intelligent soot-blowing equipment expends less energy for more effective returns when cleaning the heat-transfer surfaces. Additionally, this system automatically starts a cleaning cycle based on changes in the steam and backend flue gas temperatures, rather than waiting for operators to react. Prior to the integration into the neural network system, the sootblowers were being used too frequently on the pendants and caused significant tube wear and required significant tube replacement during outages.

Both units were previously equipped with waterwall blowers. The wall blowers were removed from service in the late 1980s, to allow for better temperatures in the upper areas of the furnace and to increase boiler efficiency. After the wall blowers were removed, curved tube panels around the penetration were replaced with straight wall panels.

The facility has spent the last two decades optimizing boiler tube cleaning to maintain proper steam temperatures with the units' intelligent sootblower system. When certain sootblowers are out of service for maintenance, the facility notices a decrease in steam temperatures, which shows that the current intelligent sootblower system is key to maintaining boiler efficiency. As such, no further actions are feasible to improve the plant heat rate from intelligent sootblowers. Therefore, no heat rate improvement can be quantified, and costs have not been developed.

The neural network and sootblower additions appear to have optimized steam temperatures as much as possible, without surface addition, to keep the deficit in steam temperature from impacting efficiency even more. The data from ISES Unit 1 and Unit 2 show that the main steam and hot reheat temperatures both improved after the neural network and sootblower installation, though mostly at lower unit operating loads. Steam temperature data for Units 1 and 2 both before and after the NN/sootblower implementation were reviewed. Not only did the average temperatures get closer to the boiler design points, but the range of temperatures narrowed considerably, keeping the steam temperatures more consistent. Unit 1 showed nominal increases of its average main steam and hot reheat steam at full load between 2003 and 2006. As such, there is no overall reported efficiency improvement at full load. Unit 2's average Main Steam temperature, however, increased by 28°F at full load between 2003 and 2006. It is difficult to attribute these gains directly to the implementation of the neural network or the sootblowers alone, but it appears that both may have had a positive impact on improving boiler operation. The specific change to heat rate improvement could not be quantified without further detailed analysis of the boiler operation.

2. Boiler Feed Pumps (BFP)

The boiler feed pumps for each unit at ISES are 2x50% turbine driven. The turbine-driven feedwater pump requires larger boilers per MW of energy produced to account for lost generation from steam extraction; however, turbine driven pumps have better overall efficiency since mechanical power does not have to be converted to electrical power. Current efficiencies of Low Pressure (LP) steam turbines reach over 90%, while standard motors are limited to efficiencies around 85%. Due to the size of the ISES boilers, it is most efficient to continue utilizing a turbine driven boiler feed pump than a motor driven pump.

BFP flow data has been collected for both pumps on both units. The Unit 1 1A and 1B pumps have been operating on or above the performance curve for the most recent sets of test data [2007, 2009, and 2010]. In 2018, a third-party performance test was conducted on the Unit 2 BFPs and found pump 2A to be performing above design, while pump 2B performance was inconclusive due to testing error; however, a previous test from 2015 showed performance was well above the design curve. Therefore, it appears that the BFPs are currently operating according to their original manufacturer's specification. This is due to the regular maintenance that is performed on the turbine and volute portion of the BFPs.

The facility maintains a regular schedule for turbine section overhauls, which includes the boiler feed pump turbine overhaul occurring approximately every 10 years. In addition, the boiler feed pump volutes are overhauled every four to seven years and allow the pumps to return to near-design efficiency. A spare volute is utilized to minimize the outage time frame allowing for minimal operational impacts. This is a typical overhaul schedule for the industry based on typical manufacturer specifications. The individual overhaul history is listed in Table 1:

| Unit | BFP | Last Overhaul | Next Overhaul |
|---|---|---|---|
| 1 | A | Volute: 2019<br>Turbine: 2017 | Volute: 2023<br>Turbine: 2027 |
| 1 | B | Volute: 2015<br>Turbine: 2017 | Volute: 2021<br>Turbine: 2027 |
| 2 | A | Volute: 2018<br>Turbine: 2012 | Volute: 2022<br>Turbine: 2022 |
| 2 | B | Volute: 2014<br>Turbine: 2012 | Volute: 2021<br>Turbine: 2022 |

*Table 1: Boiler Feed Pumps Overhaul Schedule – Independence Station*

Since the BFPs have been overhauled within the suggested period and will continue to be overhauled on a regular schedule, no additional heat rate impact has been quantified and no costs have been developed.

3. Air Preheater

ISES Units 1 and 2 each have 2 x 50% trisector Ljungström regenerative air preheaters. Air preheaters improve plant efficiency by recovering useful heat from the economizer outlet flue gas and using it to preheat incoming primary and secondary combustion air. Internal mechanical baskets travel through the hot flue gas side, absorb heat, and rotate through a sealed wall to transfer the heat to the cooler primary and secondary combustion air. These pieces of equipment are susceptible to some leakage, though, as a fraction of the higher-pressure combustion air will leak past the seals and enter the lower pressure flue gas stream. This leakage can occur in the form of direct radial and axial leakage, bypass leakage around and within the rotors, and entrainment within the rotors during rotation. This combined leakage increases the required auxiliary load on the air and flue gas fans and has a negative effect on unit heat rate. Furthermore, air in-leakage upstream of the air preheater or downstream through the remaining equipment is also possible and will also increase the load on the ID fans.

To minimize leakage, the seals are visually inspected every year and repaired as needed. Additionally, seals are replaced completely every two years when the water washing of the air preheater baskets is completed. The last air preheater seal replacement took place in Spring 2019 on Unit 1 and Fall 2018 on Unit 2, when the baskets were also replaced. The air preheater OEM has noted that there is no manufacturer recommend standard seal replacements interval; rather regular inspections of the sealing surfaces at outages will dictate if seals are worn and need to be replaced. For trisector air preheaters a timeframe of every two years is typically sufficient. Since the air preheater seals have been replaced within the manufacturer's suggested period and will continue to be replaced and/or repaired on a regular schedule, no heat rate impact due to seal replacement has been quantified and no costs have been developed.

4. Variable Frequency Drives (VFD)

ISES Units 1 and 2 do not have Variable Frequency Drives (VFDs) controls for the ID fans. For a fan equipped with a variable frequency drive (VFD) or variable speed drive (VSD), the positions of the inlet vanes are fixed, and the speed of the fan varies. In this design, the efficiency of the fan is nearly constant at all operating loads. Although VFDs have become more relevant in coal plant operations as power dispatched from these facilities are not always at base load, they are typically implemented on centrifugal fans, due to centrifugal fan inefficiency that is inherent at low loads. ISES Units 1 and 2 have axially driven ID fans that utilize variable inlet vanes (VIV). Axial fan efficiency is typically excellent at full load and good at part load and generally better than centrifugal fans. VIV provides even further benefit. These VIV inherently provide high efficiency at various turndown levels from their design point by allowing the ID fans to change the flue gas volume at lower unit operating loads.

To convert the VIV design to the VFD design is not a simple modification and would likely include complete replacement of the fans due to age and design. Nonetheless, replacing the VIV drive with VFD driven motors would not provide additional efficiency improvement at turndowns and, therefore, is not a feasible way to improve the plant heat rate. As such no costs are provided for installation of VFDs on the existing ID fan motors.

The boiler feed pumps are driven via steam turbines rather than motors, so VFDs are not applicable to those systems. Therefore, there is no opportunity to provide heat rate improvement by using VFDs on the boiler feed pumps; as such, no costs are provided for installation of VFDs on the existing BFPs.

5. Blade Path Upgrade (Steam Turbine)

Each unit at ISES includes a GE turbine with one single flow HP turbine, one double flow IP turbine, and two double flow LP turbines, commissioned in 1983 and 1984 for Unit 1 and Unit 2, respectively. The facility performs regular maintenance overhauls of the turbine sections. Maintenance overhauls help return turbine sections back to efficiencies closer to original design by repairing seals and valves, cleaning, and repairing particle erosion. Typically, the HP section is overhauled every 10 to 12 years, IP section every 8 years, and the LP sections every 10 years. The HP sections were overhauled in 2019 and 2012 for Unit 1 and Unit 2, respectively. The IP turbine section overhauls were last performed in 2019 for Unit 1 and 2018 for Unit 2. The last LP section overhaul was 2013 for Unit 1 and 2012 for Unit 2. As such, all sections of the turbines have been overhauled within the last 10 years. Overhaul activities typically include seal replacements, valve replacements, limiting clearances between blade and shell, cleaning any debris or accumulation on turbine blades, and repairing any leakages. After individual section overhauls, it is difficult to quantify the change in plant heat rate due to the other plant maintenance activities that occurred during the same time. ISES, along with most facilities, does not perform a performance test before and after overhauls, thus making it difficult to understand the exact change in efficiency. Overhauls do not provide a meaningful change in performance compared to the OEM original design.

Upgrades to steam turbines can include, but are not limited to: complete retrofits of rotors and diaphragms with modern technology, addition of stages, exhaust annulus optimization, re-blading (complete or partial), and modifications to sealing system. Facilities that have already performed upgrades in the past 10-15 years can see additional improvements in heat rate with new modifications, though the returns are generally greatest for original steam turbines with legacy configurations. When reviewing potential steam turbine upgrades, consideration must be given to the remaining life of the facility and its planned operating strategy. If a facility plans to run frequently at lower loads, certain upgrades may not provide the full yield in terms of heat rate and efficiency improvement while other upgrades may be more effective. Historically, optimization of steam turbines has been performed in order to allow better operating efficiencies at high operating loads. It is worth noting that many of these optimizations at high loads will have an inverse effect on efficiency and heat rate at low loads. Given the frequent operation of ISES below 50% load, this should be considered in evaluating whether steam turbine upgrades would achieve greater operating efficiency.

Based on discussions with GE, they have noted that upgrades to 30+ year old turbines of ISES size can yield heat rate improvements of around 2.1%. The largest opportunity for HRI lies with the LP section which accounts for approximately 50% of the overall improvement potential. The HP and IP sections account for the remaining 50% of the improvement, with the majority going to the HP section. Partial upgrades can be completed at lower capital costs but yield less heat rate improvements.

In 2004, ISES Unit 2 performed an upgrade on the HP section of its steam turbine; Unit 1 has not performed any upgrade work to date. Alstom performed the upgrade on Unit 2 and replaced the 1970s blade technology with their modern technology. At the time of the assessment this upgrade was guaranteed to increase the overall turbine efficiency by 1.74%, which is equivalent to approximately 190 Btu/kWh-n. The installation took between five and six weeks to perform. The facility performed the upgrade to improve the efficiency of the facility; it was not performed nor has it been used to increase the power output of the facility. It is expected that a similar upgrade could be performed on Unit 1 and improve efficiency; however, recent discussions with GE, who are responsible for legacy Alstom turbines, predicts between 0.75 and 1.50% improvement. This upgrade would be anticipated to cost about $8,500,000 in 2020 dollars utilizing a 3% escalation factor per year. In addition to the subcontracted cost, this upgrade would entail an outage of up to six weeks to perform the retrofit; this may not require additional downtime if conducted within a future planned seven to eight-week overhaul outage.

IP turbine upgrades tend to equate to the smallest gains in overall turbine efficiency. GE has noted that the IP turbines at ISES could be upgraded with modern technology to yield heat rate improvements of between 0.4% and 1.0%. Based on vendor guidance, these upgrades could cost between $3,500,000 and $8,800,000 per unit. In addition to the subcontracted cost, this upgrade would entail an outage of up to six weeks to perform the retrofit; this may not require additional downtime if conducted within a future planned seven to eight-week overhaul outage.

GE advised that a complete retrofit of legacy LP turbines similar to those at ISES with modern blade technology could yield the highest heat rate improvement of any of the sections; between 1.0 and 2.5%. Project pricing for an LP turbine upgrade on a similar unit in 2017 to replace the original LP steam turbine was reviewed. This upgrade is anticipated to cost around $17,200,000 in 2020 dollars utilizing a 3% escalation factor per year. In addition to the subcontracted cost, this upgrade would entail an outage of up to six weeks to perform the retrofit; this may not require additional downtime if conducted within a future planned seven to eight-week overhaul outage.

Overall, based on historical information and vendor guidance, Unit 1 could improve heat rate by 2.1% total. It should be noted that the potential heat rate improvement for each section of the turbines is not necessarily additive. For example, increasing the efficiency of the IP section results in lowering the energy of the steam leaving the IP section and entering the LP section. This would negatively affect the LP turbine's output. An upgrade to the HP section would also alter the load on the boiler reheater, as more energy would be required to reach the design Hot Reheat Steam temperature. GE noted that it is probable that Unit 1 could achieve a

2.1% improvement and Unit 2 could achieve 1.15% improvement, but a full heat balance analysis would need to be completed for each unit in coordination with the turbine and boiler OEMs to determine precise heat rate improvements. The overall cost is expected to be around $31,300,000 by upgrading the HP/IP/LP turbines on Unit 1. Unit 2 could improve its IP/LP sections for a total cost of about $22,300,000. These costs are reflective of OEM and installation costs only. Other direct and indirect project costs outlined by the EPA Control Cost Manual would increase total project costs to $37,968,000 for Unit 1 and $27,046,000 for Unit 2.[2]

It should be noted that these estimates are based on historical and high-level vendor information and would have to be more closely studied by the turbine OEM to confirm guaranteed performance and cost. The maximum ACE suggestion of up to 2.9% may be possible if the high end of improvement is achieved on all three sections; however, this is not expected to be likely and should not be considered until guarantees have been received by the OEM. Additionally, further review would be needed to determine if such upgrades would result in potential NSR implications, which could require significant additional capital expenditures.

6. Economizer

The economizers at ISES Units 1 and 2 were replaced between 2008 and 2009. The replacements were completed to eliminate back-pass plugging that was previously experienced, which ultimately improved the overall heat transfer. Offset finned tubes were replaced with in-line non-finned tubes and additional tube bundles were installed to maintain total surface area without the fins. By replacing the economizers ISES improved the operation of the economizers while maintaining cleaner surface area; however, since the replacements were completed to maintain the same total surface area, there was not expected to be a difference in performance compared to original design. With cleanings conducted every year, the economizers continue to operate consistently.

Over the past year, station operating data suggests that the economizer outlet feedwater temperature supply to the drum is 631°F for Unit 1 and 633°F for Unit 2 on average at full load. While a design feedwater outlet temperature is not specified in the boiler data pages, B&W cites that a 50°F approach to saturation is

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typical for boilers of ISES' generation.[3] Based on the pressure conditions and the approach temperature, the feedwater exit temperature should be 633°F. This suggests the water-side efficiency is still operating as designed.

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- Formal heat rate analysis is performed for each unit to generate an up-to-date heat rate curve at least annually.
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- Heat rate training is provided to each new production employee and must include theory, controllable losses, plant specific heat rate processes and the impact thereof.
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- A PM is generated for the calibration of Tier 1 instrumentation critical to heat rate analysis; it is performed at least annually.
- All heat rate related issues are reported to plant management for evaluation.

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- Auxiliary power reduction is evaluated to improve heat rate as long as unit reliability is not put at risk.
- Heat rate improvement projects are identified and submitted based on heat rate monitoring results.

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# ARKANSAS DIVISION OF ENVIRONMENTAL QUALITY (DEQ)
# AFFORDABLE CLEAN ENERGY (ACE)
# ANALYSIS FOR WHITE BLUFF STATION

## RESPONSE TO AGENCY QUESTIONS

FINAL REV 0

April 17, 2020
Project No. 13603-002

Sargent & Lundy

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## Introduction

In January 2020, Sargent & Lundy LLC (S&L) conducted a heat rate review of the White Bluff Steam Electric Station (WB) on behalf of Entergy. The review was conducted in response to an information request dated November 5, 2019 from the Arkansas Division of Environmental Quality (ADEQ) and included an assessment of potential heat rate improvement technologies that could be applied to WB Units 1 and 2. S&L evaluated each technical alternative identified by ADEQ in the information request to determine whether they are technically feasible at WB as a means of improving heat rate and thus reducing $CO_2$ emissions on a pound per megawatt-hour (lb/MWh) basis. The purpose of this report is to provide technical responses, prepared by S&L on behalf of Entergy, to specific questions in the November 5, 2019 information collection request.

*Basis and Limitations*

Heat rate improvement technologies identified in ADEQ's information request were evaluated for each unit based on site-specific analyses. Site operating data was collected, previous studies were reviewed and interviews with personnel were conducted to determine whether any of the candidate technologies had already been implemented and what actual heat rate improvements were realized, if any. Technically feasible and available technologies were evaluated at a conceptual level for both effectiveness (i.e., heat rate improvement) and costs. The review shows that it would not be feasible to apply all of the examined alternatives to an individual generating unit due to several factors, including plant design, previous equipment upgrades, and operational approaches. A more detailed evaluation of the technical feasibility, limitations, and potential heat rate improvement associated with each of the identified technologies is provided below.

*Heat Rate vs. Load*

The heat rate for WB Units 1 and 2, as with all coal-fired steam electric generating units, is closely linked to boiler operating load. Performance at full load is not representative of low load operation. While each unit can operate at gross loads up to approximately 880 MW-gross (MWg), in 2019, the facility spent almost 50% of its operating hours below 50% load.

Based on historic heat rate curves, the units operate at higher heat rates (i.e., less efficient) while operating at loads below approximately 500 MW. These higher heat rates occur when the boiler and steam turbine operate outside of full load or near-full load design conditions. As such, gross and net heat rates increase at lower load. This is also true for other equipment, including large fans and pumps, which has an additive effect on the net heat rate curve. Heat rates at lower loads can be as much as 25-35% higher than at full load. Based on historic and projected unit dispatch, it is projected that the facility will continue to operate for significant periods of time below 50% load, which will directly impact achievable heat rate and subsequent $CO_2$ emission rates. Furthermore, if future operation results in lower capacity factors than what is represented in the baseline period, then the facility will have difficulty demonstrating improvement for any of the heat rate measures evaluated below.

For this evaluation, potential heat rate improvements were evaluated at full load, unless noted otherwise. Further evaluation would be required to determine the potential of heat rate improvement for each technology at all operating load conditions. Historic operation has shown that the units spend a significant amount of time cycling, which will result in the unit spending more time operating at minimum load. As such, the impact of load on heat rate must be considered in the evaluation of the technical feasibility and effectiveness of available heat rate improvement technologies.

*Timeline Impacts*

Degradation of performance over time and seasonal impacts must be considered when evaluating heat rate improvement and developing compliance timeframes. The heat rate improvement measures evaluated herein may provide measurable improvement when first implemented; however, there is degradation that occurs over time that is expected and considered generally acceptable between major overhaul outages. As such, the heat rate improvement achievable with each technology will vary from year to year. In addition, the heat rate improvement attained with each technology may also vary from month to month due to variability in heat rate with seasonal temperatures and other ambient conditions. Seasonality and overhaul schedules must be considered in the evaluation of the technical feasibility and effectiveness of available heat rate improvement technologies, as well as baseline and future compliance time periods.

*New Source Review Compliance*

If it is determined that a heat rate improvement candidate technology is feasible, implementation of the technology must be evaluated for New Source Review (NSR) applicability. Potential NSR applicability has not been factored into the analysis of any of the heat rate improvement candidate technologies in this report. If installation of a heat rate improvement candidate technology would trigger applicability of the NSR requirements, it likely would increase the timeframe for installation due to the need to obtain a NSR permit as well as the costs of the heat rate improvement candidate technology if the installation of best available control technology ("BACT") were also necessary.

*Heat Rate Improvement Technology Costs*

The ADEQ requested facilities to utilize the Electric Power Research Institute (EPRI) Cost Manual Estimator or the EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating costs to implement the technical options.[1] However, the Control Cost Manual does not include a chapter on heat rate improvement candidate technologies rather, ADEQ references Chapter 2 of the manual, which identifies the concepts and methodology of cost estimation. Therefore, S&L utilized the approach described in the Control Cost Manual, to the extent practicable, to develop costs consistent with a study-level cost estimate. Cost estimates were developed for technically feasible options, based on unit-specific vendor budgetary quotes or historic pricing from comparable units. In addition, the EPA's Control Cost Manual was used to establish overall project costs.

*Remaining Useful Life of the Facility*

The White Bluff units will cease to use coal by December 31, 2028, pursuant to the Administrative Order between ADEQ and Entergy that was incorporated into Phase 2 of the Arkansas Regional Haze State Implementation Plan (SIP) and approved by the U.S. Environmental Protection Agency on September 27, 2019 (84 Fed. Reg. 51,033). As such, cost effectiveness calculations should consider this date when evaluating annualized capital costs.

[1] EPA Air Pollution Control Cost Manual, Seventh Edition, Chapter 2, November 2017.

## Candidate Heat Rate Improvement Technologies

1. Neural Network/Intelligent Sootblower System

WB Units 1 and 2 installed Schneider Electric's Connoisseur neural network systems and started operation in 2007. The neural network can continuously collect and interpret plant data to predict thermodynamics of the boiler. This computer analysis system is necessary to interpret large quantities of actual boiler data including combustion air flow, fuel flow, and temperature. WB's neural network system is combustion optimization software that is set up to optimize both CO and NOx for emissions control, with some functions for boiler optimization. This software adjusts trim exit gas $O_2$, burner tilts, final steam temperatures, and superheater and reheat sprays. These parameters help balance reheat and super heat steam temperatures and adjusts boiler air demand based on load.

In general, the facility has optimized the boiler operation, including excess air ($O_2$ %), to keep the CO emissions within the permit limitation. As the system is being utilized to maintain CO emissions compliance, any modification to prioritize optimization of heat rate could result in exceedances of CO. As such, no further actions are feasible to improve the plant heat rate from neural networks. Therefore, no heat rate improvement can be quantified, and costs have not been developed. Since the neural network was not operated for heat rate performance, there has been no notable impact on heat rate.

WB Units 1 and 2 are currently operating with Diamond Power intelligent sootblowers; while the system is not integrated into the neural network system, the sootblowers operate based on a "smart blow" algorithm. The sootblower cycles are initiated automatically based on steam and backend flue gas temperatures. The facility has installed the sootblowers as part of various projects dating back to the 1990s and the system now provides essentially full coverage of the pendants and economizer. Many of the changes in the intelligent sootblowing system would have impacted boiler performance after the original installation of the neural network; however, these systems have different boiler performance goals. Similar to the neural network, it is not possible to quantify the impact of the intelligent sootblowers on the facility's heat rate, especially since the sootblowers were integrated over time.

The intelligent sootblowers were installed to systematically identify specific surfaces of the boiler that need to be cleaned based on monitored gas and steam conditions. By detecting specific boiler tubes that have slag built up, the intelligent soot-blowing equipment expends less energy for more effective returns when cleaning the heat-transfer surfaces. Additionally, this system automatically starts a cleaning cycle based on changes in the steam and backend flue gas temperatures, rather than waiting for operators to react. Prior to the integration into the neural network system, the sootblowers were being used too frequently on the pendants and caused significant tube wear and required significant tube replacement during outages.

Both units were previously equipped with Diamond Power Hydrojet waterwall cleaning systems; however, these systems have not been utilized since the mid-1980s and are in the process of being removed. These were removed from service to allow for better temperatures in the upper areas of the furnace and to increase boiler efficiency.

The facility has spent the last two decades optimizing boiler tube cleaning to maintain proper steam temperatures with the units' intelligent sootblower system. When certain sootblowers are out of service for maintenance, the facility notices a decrease in steam temperatures, which shows that the current intelligent sootblower system is key in maintaining boiler efficiency. As such, no further actions are feasible to improve the plant heat rate from intelligent sootblowers. Therefore, no heat rate improvement can be quantified, and costs have not been developed.

The neural network and sootblower additions have optimized steam temperatures as much as possible, without surface addition, to keep the deficit in steam temperature from impacting efficiency even more. WB steam temperature information was reviewed before and after the neural network and sootblower operation. Main and reheat steam temperatures before the neural network and sootblower system were slightly lower than current operation, on average. However, the main improvement of the two systems has been to limit the variation in temperature. This helps the boiler maintain higher efficiencies more frequently throughout the year. It is estimated that the units each realized an average main steam and hot reheat steam temperature rise of about 10°F between 2005 and 2008. It is difficult to attribute these gains directly to the implementation of the neural network or the sootblowers alone, but it appears that both may have had a positive impact on improving boiler operation. The specific change to heat rate improvement could not be quantified without further detailed analysis of the boiler operation.

2. Boiler Feed Pumps (BFP)

The boiler feed pumps for each unit at WB are 2x50% turbine driven. The turbine-driven feedwater pump requires larger boilers per MW of energy produced to account for lost generation from steam extraction; however, turbine driven pumps have better overall efficiency since mechanical power does not have to be converted to electrical power. Current efficiencies of typical Low Pressure (LP) steam turbines reach over 90%, while standard motors are limited to efficiencies around 85%. Due to the size of the WB boilers, it is most efficient to continue utilizing a turbine driven boiler feed pump than a motor driven pump.

The facility maintains a regular schedule for turbine section overhauls, which includes the boiler feed pump turbine overhaul occurring approximately every 9-12 years along with the other turbine sections. In addition, the boiler feed pump volutes are overhauled every four to seven years, which allow the pumps to return to near-design efficiency; as such all four pumps have been rebuilt within the last four years. A spare volute is utilized to minimize the outage time frame allowing for minimal operational impacts. This is a typical overhaul schedule for the industry based on typical manufacturer specifications. The individual overhaul history is listed in Table 1:

| Unit | BFP | Last Overhaul | Next Overhaul |
|---|---|---|---|
| 1 | A | Volute: 2018<br>Turbine: 2009 | Volute: 2024<br>Turbine: 2021 |
| 1 | B | Volute: 2016<br>Turbine: 2009 | Volute: 2021<br>Turbine: 2021 |
| 2 | A | Volute: 2017<br>Turbine: 2014 | Volute: 2021<br>Turbine: 2023 |
| 2 | B | Volute: 2018<br>Turbine: 2011 | Volute: 2025<br>Turbine: 2023 |

*Table 1: Boiler Feed Pumps Overhaul Schedule – White Bluff Station*

Furthermore, Unit 2 underwent a boiler feed pump turbine upgrade of the last stage in 2014. This upgrade did not provide any additional efficiency for the BFP turbine, rather it improved reliability. The same upgrade is planned for Unit 1 in 2020.

Since the BFPs have been overhauled within the suggested period and will continue to be overhauled on a regular schedule, no additional heat rate impact has been quantified and no costs have been developed.

3. Air Preheater

WB Units 1 and 2 have 2 x 50% trisector Ljungström regenerative air preheaters. Air preheaters improve plant efficiency by recovering useful heat from the economizer outlet flue gas and using it to preheat incoming primary and secondary combustion air. Internal mechanical baskets travel through the hot flue gas side, absorb heat, and rotate through a sealed wall to transfer the heat to the cooler primary and secondary combustion air. These pieces of equipment are susceptible to some leakage, though, as a fraction of the higher-pressure combustion air will leak past the seals and enter the lower pressure flue gas stream. This leakage can occur in the form of direct radial and axial leakage, bypass leakage around and within the rotors, and entrainment within the rotors during rotation. This combined leakage increases the required auxiliary load on the air and flue gas fans and has a negative effect on unit heat rate. Furthermore, air in-leakage upstream of the air preheater or downstream through the remaining equipment is also possible and will also increase the load on the ID fans.

To minimize leakage, the seals are visually inspected every year and repaired as needed. The facility has utilized active sealing technology for the last 20 years. The last air preheater seal replacement was in Fall 2018 on Unit 1 when the baskets were also replaced. The Unit 2 seals will next be replaced in Fall of 2020 when the enamel coated baskets are installed. The air preheater OEM has noted that there is no manufacturer recommended standard interval for seal replacement; rather, regular inspections of sealing surfaces at outages will dictate if seals are worn and need to be replaced. For trisector air preheaters a timeframe of every two years is typically sufficient. WB fully replaces seals every two years when water washing is completed on the air preheater baskets, with seals added as needed every 12 months. Since the air preheater seals have been and will continue to be replaced and repaired on a regular schedule, no heat rate impact is quantified and no costs have been developed.

4. Variable Frequency Drives (VFD)

WB Units 1 and 2 do not have Variable Frequency Drives (VFDs) controls for the ID fans. For a fan equipped with a variable frequency drive (VFD) or variable speed drive (VSD), the positions of the inlet vanes are fixed, and the speed of the fan varies. In this design, the efficiency of the fan is nearly constant at all operating loads. Although VFDs have become more relevant in coal plant operations as power dispatched from these facilities are not always at base load, they are typically implemented on centrifugal fans, due to centrifugal fan inefficiency that is inherent at low loads. WB Units 1 and 2 have axially driven ID fans that utilize variable inlet vanes (VIV). Axial fan efficiency is typically excellent at full load and good at part load and generally better than centrifugal fans. VIV provides even further benefit. These VIV provide high efficiency at full load and reduced efficiency at various turndown levels from their design point by allowing the ID fan to change the flue gas volume at lower operating loads.

To convert the VIV design to the VFD design is not a simple modification and would likely include complete replacement of the fans due to age and design. Nonetheless, replacing the VIV drive with VFD driven motors would not provide additional efficiency improvement at turndowns and, therefore, is not a feasible way to improve the plant heat rate. As such no costs are provided for installation of VFDs on the existing ID fan motors.

The boiler feed pumps are driven via steam turbines rather than motors, so VFDs are not applicable to those systems. Therefore, there is no opportunity to provide heat rate improvement by using VFDs on the boiler feed pumps; as such, no costs are provided for installation of VFDs on the existing BFPs.

5. Blade Path Upgrade (Steam Turbine)

Each unit at WB includes a GE turbine with one single flow HP turbine, one double flow IP turbine, and two double flow LP turbines, commissioned in 1981 and 1982 for Units 1 and 2, respectively. The facility performs regular maintenance overhauls of the turbine sections. Maintenance overhauls help return turbine sections back to efficiencies closer to original design by repairing seals and valves, cleaning, and repairing particle erosion. Prior to 2010, the turbine sections were overhauled every 6-8 years. At this time, with lower operating hours per year, the duration between overhauls has increased to approximately 11-12 years. The last turbine overhaul outages were 2009 for Unit 1 and 2014 for Unit 2. The next planned overhauls for the steam turbines are in 2021 for Unit 1 and 2023 for Unit 2. Overhaul activities typically include seal replacements, valve replacements, limiting clearances between blade and shell, cleaning any debris or accumulation on turbine blades, and repairing any leakages. After individual section overhauls, it is difficult to quantify the change in plant heat rate due to the other plant maintenance activities that occurred during the same time. WB, along with most facilities, does not perform a performance test before and after overhauls, thus making it difficult to understand the exact change in efficiency. Overhauls do not provide a meaningful change in performance compared to the OEM original design. A full train overhaul costs approximately $10-15M to complete and is currently planned to take place prior to the compliance period. Since this is a previously scheduled typical maintenance activity, no additional heat rate impact is expected.

Upgrades to steam turbines can include, but are not limited to: complete retrofits of rotors and diaphragms with modern technology, addition of stages, exhaust annulus optimization, re-blading (complete or partial), and modifications to sealing system. Facilities that have already performed upgrades in the past 10-15 years can see additional improvements in heat rate with new modifications, though the returns are generally greatest for original steam turbines with legacy configurations. When reviewing potential steam turbine upgrades, consideration must be given to the remaining life of the facility and its planned operating strategy. If a facility plans to run frequently at lower loads, certain upgrades may not provide the full yield in terms of heat rate and efficiency improvement while other upgrades may be more effective. Historically, optimization of steam turbines has been performed in order to allow better operating efficiencies at high operating loads. It is worth noting that many of these optimizations at high loads will have an inverse effect on efficiency and heat rate at low loads. Given the frequent operation at WB below 50% load, this should be considered in evaluating whether steam turbine upgrades would achieve greater operating efficiency.

Based on discussions with GE, they have noted that upgrades to 30+ year old turbines of WB size can yield heat rate improvements around 2.1%. The largest opportunity for HRI lies with the LP section which accounts for approximately 50% of the overall improvement potential. The HP and IP sections account for the remaining 50% of the improvement, with the majority going to the HP section. Partial upgrades can be completed at lower capital costs but yield less heat rate improvements.

Independence Steam Electric Station (ISES) is also owned and operated by Entergy and is a sister facility to WB. ISES performed an upgrade on the HP section of the Unit 2 steam turbine in 2004. Alstom performed the upgrade on Unit 2 and replaced the 1970s blade technology with their modern technology. At the time of the assessment this upgrade was estimated to be able to increase the overall turbine efficiency by 1.74%, which is equivalent to approximately 190 Btu/kWh-n. ISES performed the upgrade to improve the efficiency of the facility; it was not performed nor has it been used to increase the power output of the facility. Based on the facilities all having the same original turbine design, it is expected that a similar upgrade could still be performed on both units at WB and improve efficiency by approximately 1.74% or 190 Btu/kWh-n as well, per unit. This upgrade is anticipated to cost $8,500,000 in 2020 dollars utilizing a 3% escalation factor per year. In addition to the subcontracted cost, this upgrade would entail an outage of up to six weeks to perform the retrofit; this may not require additional downtime if conducted within a future planned 10 week full-train overhaul outage duration.

IP turbine upgrades tend to equate to the smallest gains in overall turbine efficiency. GE has noted that the IP turbines at WB station could be upgraded with modern technology to yield heat rate improvements between 0.4% and 1.0%. Based on vendor guidance, these upgrades could cost between $3,500,000 and $8,800,000 per unit. In addition to the subcontracted cost, this upgrade would entail an outage of up to six weeks to perform the retrofit; this may not require additional downtime if conducted within a future planned 10 week full-train overhaul outage duration.

GE advised that a complete retrofit of legacy LP turbines similar to those at WB with modern blade technology could yield the highest heat rate improvement of any of the sections; between 1.0 and 2.5%. Project pricing for an LP turbine upgrade on a similar unit in 2017 to replace the original LP steam turbine was reviewed. This upgrade is anticipated to cost around $17,200,000 in 2020 dollars utilizing a 3% escalation factor per year. In addition to the subcontracted cost, this upgrade would entail an outage of up to six weeks to perform the retrofit; this may not require additional downtime if conducted within a future planned 10 week full-train overhaul outage duration.

Overall, based on historical information and vendor guidance, Units 1 and 2 at WB could each improve heat rate by 2.1% total. It should be noted that the potential heat rate improvement for each section of the turbines is not necessarily additive. For example, increasing the efficiency of the IP section results in lowering the energy of the steam leaving the IP section and entering the LP section. This would negatively affect the LP turbine's output. An upgrade to the HP section would also alter the load on the boiler reheater, as more energy would be required to reach the design Hot Reheat Steam temperature. A full heat balance analysis would need to be completed in coordination with the turbine and boiler OEMs to determine precise heat rate improvements. The overall cost is expected to be around $31,300,000 by upgrading the HP/IP/LP turbines per unit. These costs are reflective of OEM subcontracted costs only. Other direct and indirect project costs outlined by the EPA Control Cost Manual would increase total project costs to $37,968,000 per unit.[2]

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It should be noted that these estimates are based on historical and high-level vendor information and would have to be more closely studied by the turbine OEM to confirm guaranteed performance and cost. The maximum ACE suggestion of up to 2.9% may be possible if the high end of improvement is achieved on all three sections; however, this is not expected to be likely and should not be considered until guarantees have been received by the OEM. Additionally, further review would be needed to determine if such upgrades would result in potential NSR implications, which could require significant additional capital expenditures.

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Over the past year, station operating data suggests that the economizer outlet feedwater temperature supply to the drum is 644°F for Unit 1 and 629°F for Unit 2 on average at full load. While a design feedwater outlet temperature is not specified in the boiler data pages, B&W cites that a 50°F approach to saturation is typical for boilers of WB's generation.[3] Based on the pressure conditions and the approach temperature, the feedwater exit temperature should be 633°F. This suggests the water-side efficiency is still operating as designed.

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AR-20-002

April 17, 2020

Mr. Will Montgomery
Associate Director
Office of Air Quality
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Arkansas Department of Energy and Environment
5301 Northshore Drive
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RE: Information Request to Entergy Arkansas Regarding Anticipated Future Operating Characteristics

Dear Mr. Montgomery:

On November 5, 2019, Entergy Arkansas, LLC (EAL) received a request for information from DEQ pertaining to anticipated future operating characteristics of EAL's four existing coal-fired steam electric utility generating units:

- White Bluff Unit 1
- White Bluff Unit 2
- Independence Unit 1
- Independence Unit 2

DEQ requested that Entergy provide future operating characteristics, sources for obtaining the information, or feedback on the best methods to collect the information. The specific operating characteristics that DEQ requested include:

1. Annual generation.
2. $CO_2$ emissions.
3. Fuel use, fuel prices, and fuel carbon content.
4. Fixed and variable operations and maintenance costs.
5. Heat rates.
6. Electric generation capacity and capacity factors.

Enclosed with this letter are unit-specific operating data and information reflecting operating characteristics of EAL's coal units over the most recent five years. Much of the information may be obtained from EPA's Clean Air Markets Division (CAMD) website. Annual generation, $CO_2$

emissions, and calculated annual average heat rates on a unit-base level were produced through querying CAMD. This information can be used to determine future operating characteristics for the units' remaining useful life, based on the dates by which the units will cease to use coal. The White Bluff units will cease to use coal by December 31, 2028, pursuant to the Administrative Order between ADEQ and Entergy that was incorporated into Phase 2 of the Arkansas Regional Haze State Implementation Plan (SIP), and approved by the U.S. Environmental Protection Agency on September 27, 2019 (84 Fed. Reg. 51,033). Entergy plans to cease coal-fired operations of the Independence units by December 31, 2030, as the DEQ noted in Phase 2 of the Regional Haze SIP. Entergy has entered into a proposed settlement agreement with Sierra Club and National Parks Conservation Association that is currently pending before the U.S. District Court for the Eastern District of Arkansas (*Sierra Club, et al. v. Entergy Arkansas, LLC, et al.*, No 4:18-cv-00854 -KGB (E.D. Ark.)). If the court approves the settlement, the cessation of coal-fired operation at the Independence units will become an enforceable commitment.

As demonstrated by the enclosed data, individual unit operation has the potential to vary from one year to the next. Annual capacity factors for individual units have been as low as 33% and as high as 69% over the last five years. While capacity factors have varied over the years and will continue to do so in the future, a key characteristic directly affecting unit capacity factors is the percentage of time the units spend operating within different load ranges. As these two characteristics are evaluated together in the context of developing a state plan for ACE, thorough consideration should be given to the fact that how the coal-fired units are dispatched from one period to the next may differ substantially. For instance, hypothetically, if a unit is operated for 9 months out of a year and it is operated that entire duration at load of 250 MWg, its annual capacity factor would be roughly 21% at the end of the year. If the following year the unit is operated for only 3 months and it is operated the entire duration at a load of 880 MWg, its annual capacity factor would be roughly 25%. While the capacity factors are similar for both years in this hypothetical scenario, average heat rate performance would be substantially different. Heat rate performance varies significantly between operation at the lower load range and operation at the upper load range. Further details illustrating the relationship between heat rate performance and load operation is provided in EAL's candidate technology ICR responses prepared by Sargent & Lundy, LLC for White Bluff and Independence. There are noteworthy differences in how the units have been dispatched just over the last few years as seen in the attached data. For instance, in 2017, Independence Unit 2 spent over two-thirds of its operating time at loads greater than 750 MW gross. On the other hand, in 2016, White Bluff Unit 1 spent just under one-half of its operating time at loads less than 350 MW gross. If it is proposed that a single CO2 standard be designated for each unit, it will be critical that the averaging period be long enough such that the standard will not restrict or limit the load at which EAL's coal units can dispatch. Alternatively, ADEQ could consider establishing multiple CO2 standards for different load bins.

It is anticipated each of the four coal units will operate their remaining useful life similarly to the last five years. While future operating characteristics are not expected to significantly change between now and the time Independence and White Bluff cease to burn coal, EAL's 2018 Integrated Resource Plan (IRP) provides some additional details regarding future anticipated operation of the coal units. In order to provide the Arkansas Public Service Commission (APSC) and stakeholders insight into the company's long-term planning process for meeting future demand and energy needs, EAL submits an IRP to the APSC once every three years. The most recent report, submitted October of 2018, can be seen at the following web address: https://www.entergy-arkansas.com/integrated_resource_planning/.

While the most recent IRP was submitted less than one and a half years ago, it is imperative to understand that many factors which influence how EAL's power generation facilities are dispatched from year to year, or even month to month, can often be very volatile and outside of EAL's control. Natural gas prices are a key economic factor contributing to both how and whether the coal-fired units will be dispatched. The October 2018 IRP uses NYMEX Henry Hub forward prices for forecasting future natural gas prices. The natural gas forecast used in the IRP includes cases for high and low gas prices to support analysis across a range of future scenarios. In levelized 2018 dollars per MMBtu, the reference case natural gas forecast for 2020 was $3.88, the low case was $2.59, and the high case was $5.43. As of April 8, 2020, natural gas prices for the year have remained below EAL's low case projection for the entire calendar year, thus far ranging anywhere from $1.60 to $2.20 per MMBtu. These natural gas prices have been remarkably lower than the IRP's projected, delivered coal price of $2.30/MMBtu and have led to the coal units' low utilization over the first quarter of 2020. Accounting for all four coal units' operation during the first quarter, they have operated at an average capacity factor of approximately 15% combined based on a nominal 880 MWg capacity per unit.

Entergy does not have publicly available information relating to fixed and variable operations and maintenance costs. Entergy recommends that DEQ evaluate data available from the U.S. Energy Information Administration (EIA). For example, EIA provides average power plant operating expenses for different types of electricity providers at https://www.eia.gov/tools/faqs/faq.php?id=19&t=3.

If you have any questions regarding this submittal, please contact me at (501) 377-4038 or Stan Chivers at (501) 377-4033.

Sincerely,

Russell McLaren

Russell McLaren
Manager, Arkansas Environmental Support

RBM/sac

cc: Stan Chivers
File 8212.1

## Operational Data Over Last 5 Years

| Year | Unit | Heat Input (MMBtu) | Gross Load (MW-h) | Operating Time (Hrs) | Operating Time <350 MW gross (Hrs) | Operating Time >750 MW gross (Hrs) | Gross Heat Rate (BTU/kWh) | Average Operating Load (MW gross) | Capacity Factor * (%) | CO2 emissions (short tons) | Coal burned (short tons) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | ISES1 | 27,697,314 | 2,941,455 | 5,885 | 1,947 | 1,323 | 9,416 | 500 | 38.16 | 2,903,652.7 | 1,752,680 |
| | ISES2 | 25,660,273 | 2,600,895 | 5,332 | 2,185 | 1,245 | 9,866 | 488 | 33.74 | 2,690,312.3 | 1,535,703 |
| | WB1 | 34,271,100 | 3,246,556 | 6,052 | 1,704 | 1,708 | 10,556 | 536 | 42.11 | 3,593,129.3 | 1,798,850 |
| | WB2 | 34,435,657 | 3,305,975 | 6,392 | 1,355 | 1,023 | 10,416 | 517 | 42.89 | 3,609,929.2 | 1,944,792 |
| 2016 | ISES1 | 37,586,780 | 4,036,396 | 6,918 | 1,770 | 2,587 | 9,312 | 583 | 52.22 | 3,941,456.7 | 2,381,443 |
| | ISES2 | 40,942,319 | 4,104,368 | 7,493 | 2,689 | 2,614 | 9,975 | 548 | 53.10 | 4,293,586.0 | 2,437,778 |
| | WB1 | 28,495,838 | 2,617,383 | 5,906 | 2,712 | 1,321 | 10,887 | 443 | 33.86 | 2,986,331.9 | 1,571,442 |
| | WB2 | 35,653,694 | 3,400,181 | 6,422 | 1,718 | 1,595 | 10,486 | 529 | 43.99 | 3,738,847.0 | 1,980,397 |
| 2017 | ISES1 | 30,753,729 | 3,325,300 | 5,373 | 820 | 2,215 | 9,248 | 619 | 43.14 | 3,224,688.7 | 1,910,450 |
| | ISES2 | 45,437,955 | 4,683,537 | 6,425 | 560 | 4,090 | 9,702 | 729 | 60.76 | 4,765,083.4 | 2,707,786 |
| | WB1 | 53,598,137 | 5,075,189 | 7,494 | 1,031 | 4,331 | 10,561 | 677 | 65.84 | 5,620,907.6 | 2,967,154 |
| | WB2 | 33,600,022 | 3,298,394 | 5,036 | 429 | 2,361 | 10,187 | 655 | 42.79 | 3,523,059.3 | 1,815,317 |
| 2018 | ISES1 | 50,885,544 | 5,146,433 | 7,603 | 559 | 3,961 | 9,888 | 677 | 66.76 | 5,336,444.9 | 2,954,924 |
| | ISES2 | 50,063,483 | 4,990,528 | 6,682 | 254 | 4,324 | 10,032 | 747 | 64.74 | 5,250,189.4 | 2,856,874 |
| | WB1 | 36,418,788 | 3,436,776 | 4,891 | 545 | 3,172 | 10,597 | 703 | 44.58 | 3,819,075.3 | 2,045,509 |
| | WB2 | 51,803,856 | 5,178,030 | 7,479 | 536 | 4,163 | 10,005 | 692 | 67.17 | 5,432,215.5 | 2,998,838 |
| 2019 | ISES1 | 30,881,745 | 2,831,581 | 6,041 | 2,139 | 771 | 10,906 | 469 | 36.73 | 3,238,224.3 | 1,673,529 |
| | ISES2 | 34,912,243 | 3,183,116 | 5,890 | 1,561 | 1,462 | 10,968 | 540 | 41.29 | 3,660,659.0 | 1,858,178 |
| | WB1 | 43,449,036 | 3,838,491 | 6,884 | 1,544 | 2,321 | 11,319 | 558 | 49.79 | 4,555,582.0 | 2,261,913 |
| | WB2 | 36,656,800 | 3,635,974 | 6,143 | 1,318 | 2,244 | 10,082 | 592 | 47.17 | 3,843,795.7 | 2,185,412 |
| **AVERAGE** | | **38,160,216** | **3,743,828** | **6,317** | **1,369** | **2,442** | **10,220** | **590** | **48.54** | **4,001,359** | **2,181,948** |

* The capacity factor is calculated based on load data available in CAMD and a nominal 880 MWg capacity for each unit.

| Carbon content (%) | |
|---|---|
| **Average from 2017 to 2019:** | 70.5 |

| Delivered Coal Price Forecast (volume weighted average for EAL units) | | |
|---|---|---|
| **2020-2030** | $2.30/mmBtu | Reference: EAL's 2018 IRP |