FINAL

# BROWN UNIT 3 HEAT RATE STUDY

B&V PROJECT NO. 401388
B&V FILE NO. 14.4100



PREPARED FOR

LG&E and KU

3 JUNE 2019

BLACK & VEATCH
Building a world of difference.®

# Table of Contents

## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

LG&E and KU asked Black & Veatch to support their efforts to analyze the potential response to the United States Environmental Protection Agency (EPA) Docket ID No. EPA-HQ-OAR-2017-0355, "Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program. Proposed Affordable Clean Energy (ACE) rule)." LG&E and KU operates the EW Brown Generating Station, consisting of one coal-fired electric generating unit (EGU), and specifically requested that Black & Veatch develop a high-level assessment report identifying opportunities to improve plant efficiency in order meet ACE proposal goals.

To meet these goals, a high-level description of seven primary heat rate improvement (HRI) projects that have been proposed by the EPA as the best system of emission reduction (BSER) has been prepared by Black & Veatch. Estimates of heat rate improvement, annual $CO_2$ reduction, and a rough order of magnitude capital cost estimate has been developed for each alternative.

A comprehensive assessment of the technical and economic feasibility will not be provided in this effort but should be considered in a follow-on effort under a separate phase. Follow-on studies would consist of conceptual engineering to develop more accurate performance and cost estimates for the system(s) to better determine feasibility of the options evaluated at a high level in this study.

# 2.0 Existing Plant Characteristics

Table 2-1 shows the existing estimated full-load efficiency parameters for Brown Unit 3, along with estimated net plant heat rate and $CO_2$ emissions rates. This data was gathered from the Brown Unit 3 Vista modeling re-calibration effort that was conducted in 2018, and subsequently updated in 2019.

**Table 2-1 Brown Unit 3 Full-Load Data for 2019**

| UNIT | *GROSS/ NET (MW) | NET TURBINE HEAT RATE (BTU/KWH), ACTUAL | BOILER EFFICIENCY, HHV BASIS (%) | NET PLANT HEAT RATE (BTU/KWH), | COAL BURN RATE (TON/HR) | COAL HHV (BTU/LBM) | $CO_2$ EMISSIONS (TON/HR) |
|---|---|---|---|---|---|---|---|
| Brown Unit 3 | 442/ 404.5 | 8,436 | 88.23 | 10,447 | 190.41 | 11,097 | 428.7 |

*Note the gross and net rated output for EW Brown 3 are 457MW and 413MW respectively. The data in Table 2-1 was from a test period where the unit was dispatched lower than rated conditions.

The unit consists of a Combustion Engineering subcritical pulverized coal boiler with single reheat stage. Five exhauster mills supply the boiler with coal, and combustion air is supplied by 2 forced draft fans. Two bisector Ljungstrom air heaters are utilized for air preheating. NOx control systems installed at the unit include low-NOx burners, a separated overfire air system, and an anhydrous ammonia SCR. Particulate control is by a fabric filter baghouse. $SO_2$ control is by a wet limestone tower absorber scrubber. Hydrated lime and activated carbon are injected into the flue gas ductwork to control $SO_3$ and mercury emissions, respectively

# 3.0 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening effort was developed based on a high-level analysis of Brown Unit 3, as well as Black & Veatch's experience with similar projects. The projects depicted herein were selected from heat rate improvement projects detailed by the US EPA in their ACE proposal as "BSER" projects. A detailed table summarizing the benefits and costs is included in Appendix B.

## 3.1 STEAM TURBINE BLADE PATH UPGRADES

Black & Veatch performed a review of several steam turbine blade path upgrade options. As a result of this investigation, three heat balance models of the Brown Unit 3 steam turbine were developed:

- Base: Best match of the Brown Unit 3 Thermal Kit heat balance at relevant conditions.
- Case 1: only the HP (High Pressure) and IP (Intermediate Pressure) steam path of the turbines are upgraded.
- Case 2: the entire steam path HP/IP/LP (Low Pressure turbines) are upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in house data and past project experience and are believed to be achievable. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

### 3.1.1 Base Case

The base case model is the best match of the thermal kit heat balance WB5436, which is the VWO-5% OP. The condenser pressure was set to 4.3 in HgA to keep the basis consistent across the models for comparison as against various upgrade options. The Westinghouse steam turbine on Brown Unit 3 is a two-flow turbine with 32-inch last stage blade length for the LP end. It was noticed that the maximum main steam flow rate from steam turbine heat balances was not coincident with maximum main steam flow from the boiler design data information. Based on the clarification obtained from LG&E and KU, it is noted that the steam flows from boiler documentation correspond more accurately to Brown Unit 3 conditions. As a result, the base model was not used to run at flow corresponding to VWO with 5% overpressure as it is not applicable for comparison. This model was then used to run two cases: Rated Load (Rated Pressure & Rated Flow corresponding to gross output from data for Brown Unit 3 Vista recalibration) and 75% Load (Rated Pressure reduced flow.

### 3.1.2 Case1: HP/IP Steam Path Upgrades

In this model the HP and IP sectional efficiencies were increased from approximately 85.2% and 91.3%, to approximately 91% and 94% respectively. This model was then used to run two cases: Rated Load, and 75% Load. In both cases, the boiler steam generation was reduced such that the steam turbine power output matches the values found in the corresponding cases generated by the Base model.

### 3.1.3 Case 2: Full Steam Path Upgrades

In this model the HP, IP and LP turbine sectional efficiencies were raised from approximately 85.2%, 91.3%, and 93%, to approximately 91%, 94% and 94.5% respectively. This fully upgraded model was also run under the same two conditions (Rated Load, and 75% Load), again with a reduction in boiler steam generation while holding the steam turbine power output to match the desired values.

Tables 3-1 and 3-2 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 89.13% (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required. This boiler efficiency is considered based on information provided by LG&E and KU.

**Table 3-1 Brown Unit 3 Steam Turbine Modeling Results – Rated Case**

| | | BASE MODEL RATED LOAD | UPGRADE: HP/IP | UPGRADE: HP/IP/LP |
|---|---|---|---|---|
| Boiler Efficiency (HHV) | % | 89.13% | 89.13% | 89.13% |
| STG Gross Output | kW | 442,006 | 442,006 | 442,006 |
| Turbine Heat Rate | Btu/kWh | 8,076 | 7,969 | 7,910 |
| Turbine Heat Rate Change | Btu/kWh | | -107 | -166 |
| Turbine Heat Rate Improvement | % | | 1.3% | 2.1% |
| Boiler Heat Input (HHV) | MBtu/hr | 4,005 | 3,952 | 3,923 |
| Boiler Heat Input (HHV) Change | MBtu/hr | | -53.1 | -82.3 |
| Boiler Heat Input (HHV) Improvement | % | | 1.3% | 2.1% |
| Gross Plant Heat Rate (HHV) | MBtu/hr | 9,061 | 8,941 | 8,875 |
| Gross Plant Heat Rate (HHV) Change | MBtu/hr | | -120 | -186.2 |
| Gross Plant Heat Rate (HHV) Improvement | % | | 1.3% | 2.1% |

* This boiler efficiency takes its basis from the Brown Unit 3 boiler datasheet.

**Table 3-2 Brown Unit 3 Steam Turbine Modeling Results – "75% Load"**

| | | BASE MODEL 75% LOAD | UPGRADE: HP/IP | UPGRADE: HP/IP/LP |
|---|---|---|---|---|
| Boiler Efficiency (HHV) | % | 89.13% | 89.13% | 89.13% |
| STG Gross Output | kW | 331,500 | 331,500 | 331,500 |
| Turbine Heat Rate | Btu/kWh | 8,332 | 8,229 | 8,173 |
| Turbine Heat Rate Change | Btu/kWh | | -103 | -159 |
| Turbine Heat Rate Improvement | % | | 1.2% | 1.9% |
| Boiler Heat Input (HHV) | MBtu/hr | 3,099 | 3,061 | 3,040 |
| Boiler Heat Input (HHV) Change | MBtu/hr | | -38.3 | -59.1 |
| Boiler Heat Input (HHV) Improvement | % | | 1.2% | 1.9% |
| Gross Plant Heat Rate (HHV) | MBtu/hr | 9,348 | 9,233 | 9,170 |
| Gross Plant Heat Rate (HHV) Change | MBtu/hr | | -115.5 | -178.3 |
| Gross Plant Heat Rate (HHV) Improvement | % | | 1.2% | 1.9% |

* This boiler efficiency takes its basis from the Brown Unit 3 boiler datasheet.

The estimated capital cost and HRI for the turbine upgrade options are as follows:

***HP/IP Upgrade Only***
Total Installed capital cost: $16.26 million
Heat Rate (efficiency) improvement: 1.2-1.3%

***Full Steam Path Upgrade***
Total Installed capital cost: $27.91 million
Heat Rate (efficiency) improvement: 1.9-2.1%

## 3.2 ECONOMIZER REDESIGN OR UPGRADES

The purpose of this project was to assess efficiency gains through additional flue gas heat absorption in the economizer section of the boiler through additional surface. To assess the economizer, Black &Veatch created a base case and then investigated three options: adding 1, 2, and 3 additional tube passes.

As a result of several discussions with LG&E and KU engineering personnel, the current EPRI Vista fuel quality impact model of Brown Unit 3 was updated to ensure that the boiler heat transfer model matched the current configuration of the unit. The Vista program contains a detailed linear heat transfer model that has the power to conduct "what if" analyses upon tube banks surface area configurations, and this model was utilized successfully for this study. Several simulations of tube configurations that would increase the heat transfer area of the economizer were analyzed, and these are detailed in this section. The following comments have been recorded on the feasibility of adding economizer tube surface area to Brown Unit 3.

- A review of the drawings that were supplied indicate there is no room to add any passes of economizer tube to the upper economizer sections. Any addition of tube passes may require relocation of headers.
- There was some of room to add up to 3 passes of tube at the top of the lower economizer section.

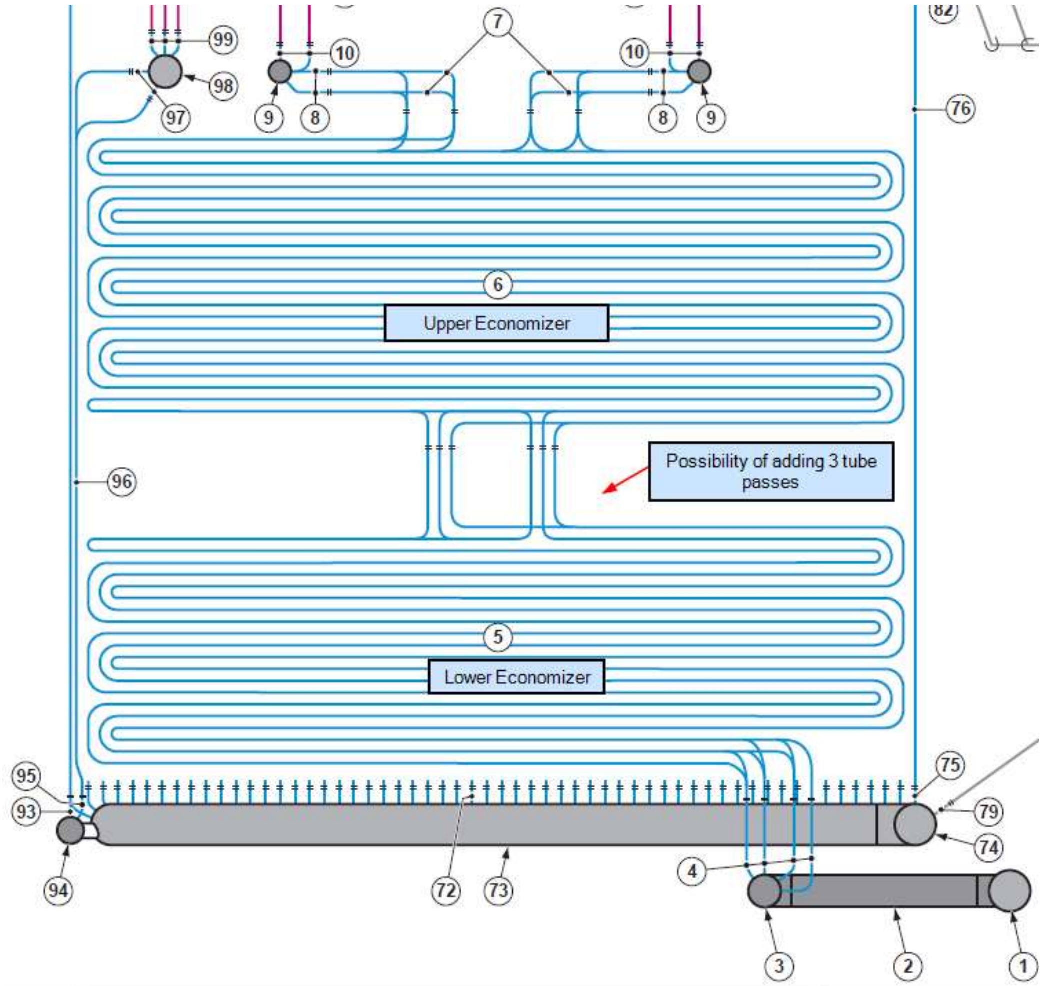



**Figure 3-1 Possible Economizer Tube Pass Additions**

- The economizer tubes have spiral fins on both lower and upper economizer sections
- Any changes to the flue gas temperature need to be sensitive to the concern of maintaining a minimum SCR gas inlet temperature of 595 °F at all load, as well as a minimum baghouse inlet temperature of 300 °F at all load.

After calibrating the Vista model of Brown Unit 3 to 442 MW gross from data collected on July 28, 2016, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 730 °F.
- Adding 1 pass to the lower economizer – SCR inlet temperature = 714 °F
- Adding 2 pass to the lower economizer – SCR inlet temperature = 700 °F
- Adding 3 passes to the lower economizer – SCR inlet temperature = 686 °F

As seen from the above results, there are no constrains in meeting the minimum SCR inlet flue gas temperatures. Only very minor changes were seen in the overall net turbine heat rate, due to small variations in the balance of heat absorbed by the feedwater, versus heat absorbed by the main steam and reheat steam. However, on an overall basis, adding tube surface area to the Brown Unit 3 economizer resulted in an improvement to the heat rate:

- Baseline case – 0% difference
- Adding 1 pass to the lower economizer - 0.07% improvement
- Adding 2 passes to the lower economizer – 0.17% improvement
- Adding 3 passes to the lower economizer – 0.25% improvement

The minimum bag filter inlet flue gas temperature was achievable except for the case where 3 tube passes are added to lower economizer, where the inlet flue gas temperature decreased to 295 °F. Note that these analyses were conducted at full-load – at lower-load operation, there is the possibility of limitation of operation of the SCR should the gas inlet temperature decrease significantly. Analysis of the impacts of lower-load operation is complicated by the fact that a proprietary hot water bypass system is installed at Brown Unit 3. At low loads, this system works to boost the flue gas inlet temperature to the SCR by the following method:

1. Hot water is pumped with an HWRS pump from the drum and into the feedwater line prior to the economizer water inlet point.
2. A flow control valve blends this drum water with feedwater from the G feedwater heaters.
3. The resulting preheated water is sent to the economizer inlet.
4. Because the inlet feedwater is higher temperature, less heat transfer occurs in the economizer, meaning that less heat is transferred from the flue gas.
5. As less heat is transferred from the flue gas, therefore the flue gas temperature leaving the economizer is increased.

Due to its complexity this specific system was not modeled as part of this study and would need to be modeled as part of a Phase 2 effort in order to establish the flexibility of Brown Unit 3 to accommodate changes to the economizer tube surface area. Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability, is about $40,000-50,000 per Btu/kWh improvement. Given a baseline average annual NPHR of 10,536

Btu/kWh as a reference point and utilizing the estimated improvements listed above, this equates to between $700,000-$900,000 for single-pass additions, to over $1,200,000 for a three-pass modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

## 3.3 AIR HEATER AND LEAKAGE CONTROL UPGRADES

The main benefit of air heater and flue gas ductwork leakage control repairs and upgrades is the improvement of a unit's NPHR by reducing the duty of the unit's combustion air and flue gas induced draft fans thus reducing the units overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional risks beyond degradation in NPHR, however. Air in-leakage also results in a tempering of flue gas, causing corrosive flue gas components to condense on air heater cold end baskets and ductwork components, resulting in degradation of equipment materials. Therefore, reducing air heater and flue gas duct leakage rates will both improve the unit's NPHR and improve overall equipment life, reducing capital investments for repair and alleviating operation and maintenance costs. Other negative impacts of high air in-leakage include:

- Higher flue gas velocities due to additional flue gas mass flow, reducing the effectiveness and life expectancy of air quality control equipment.
- Reduced life expectancy of ductwork, dampers, expansion joints, fans, and other balance of plant draft system equipment.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak-by of cold combustion air mixing with hot flue gas out of the air heater) causing flue gas to be closer to the acid dew point, increasing the potential for equipment corrosion throughout flue gas draft system.

The following sub-sections provide further discussion for air heater and leakage control upgrades to improve the Brown Unit 3 heat rate. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects and provide typical information and results for such projects that can be used to assess and further screen the potential benefit of the project for LG&E and KU at their Brown Unit 3 facility. Future Phase 2 efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

### 3.3.1 Air Heater

As noted previously, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas induced draft fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas resulting in a higher flue gas induced draft fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans, since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The Brown Unit 3 air heaters are regenerative Ljungstrom bisector type air heaters with rotating baskets in a vertical-shaft orientation. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals which are misaligned or out of adjustment will result in increased air heater leakage rates.

Air heater seal technology has advanced since the initial installation of the Brown Unit 3 air heaters, which utilize a single, rigid plate-style, sealing surface. Once these seals impact any sealing surface such as the sector places, they are typically permanently damaged and need to either be readjusted or replaced to return the air heater leakage to its previous amount. It is Black & Veatch's understanding that the original air heater seals are adjusted about every two to three years to account for damage that occurs to them over time.

To improve the sealing system, the first option discussed here is the retrofit of a different sealing technology to reduce gaps between seals and sector plates and/or improve sealing contact and to maintain it over longer periods of time. There are many proprietary methods, designs, and materials available to accomplish this which involve more resilient type seals that can withstand some level of constant contact with the sector plates, at least for a portion of the unit load range. The types of improved seal designs that are resilient (versus the rigid type currently installed) involve brush type seals and flexible metal plate and/or sheet designs. Black & Veatch recommends brush-type seals only for circumferential and axial seals as they are not as exposed to sootblower media and should provide better sealing and more resiliency than rigid seals. For the radial seals, flexible metal plate and/or sheet designs should be considered. These types of seals typically include holding and backing bars to protect the seal from sootblower media and over extension in either direction. Note that these types of seals may also involve minor modifications to the sector plates to reduce mechanical shock when contacting the sector plates.

Two additional air heater sealing technologies exists from suppliers beyond that of changing out the seal type which include duplex sealing and movable sector plates. Duplex sealing would double the number of diaphragm plates, ensuring there are always two radial seals passing under or over the sector plates. However, it would require a major retrofit of the air heater as it would require the installation of additional structure in the rotor to double up on the number of seal attachment surfaces as these additional seal attachment surfaces also serve as additional partitions between baskets. The retrofit of movable sector plates is less involved as it utilizes the existing air heater sector plates by detaching them from the air heater structure and attaching actuators to them to allow them to be raised and lowered during operation. Note that the addition of movable sector plates may negate the need for resilient type air heater seals in some locations. These two additional options involving duplex seals and movable sector plates come at a greater capital cost and the cost benefit for each application will differ based on the unit's operating characteristic, dispatch mode, and project financial requirements. These factors could be evaluated in a Phase 2 effort once it is deemed that air heater seal modifications show a positive benefit for current and planned future operation.

Based on current operating data and for Brown Unit 3, the air heater leakage is estimated to be about 16.4% at full load. This is based on an average boiler outlet $O_2$ concentration of about 2.8% seen in the summer 2018 and winter 2019 operating data at full load. This also assumes a 1% leakage at the SCR and a 2.1% total in-leakage rate downstream of the air heater gas-side for the PJFF and surrounding ductwork (estimated based on the flue gas temperature drop average of 5 °F calculated from recent operating data between the air heater and the ID fan). The SCR leakage was assumed based on the fact that there is typically some amount of leakage into the SCR casing due to it being on the hot-side of the air heater, and also due to the dilution air used in the SCR emission control process. The temperature drop across the SCR from measured gas temperature data is negligible, if any. Based on the estimated or assumed air in-leakage of and around the SCR and PJFF as well as the boiler outlet $O_2$, the air heater leakage could then be estimated using a $CO_2$ concentration (wet basis) at the stack. Future testing to more accurately determine air heater leakage is recommended to better understand the potential benefits to decreasing leakage.

Black & Veatch estimates the air heater leakage rate could be reduced to 8.0% or lower with the incorporation of movable sector plates (and seal replacements). Reducing the air heater leakage rate from 16.4% to 8.0%would reduce the FD and ID fan auxiliary power consumption by an estimated 2.5 MW at full load (442 MW) and 0.50 MW at low load (165 MW). This represents a potential improvement in NPHR of 59 Btu/kWh, or 0.59%, at full load and 12 Btu/kWh, or 0.12%, at low load.

Black & Veatch estimates the air heater leakage rate could be reduced to 6.0% or lower with the incorporation of duplex sealing along with movable sector plates (and seal replacements). Reducing the air heater leakage rate from 16.4% to 6.0% would reduce the FD and ID fan auxiliary power consumption by an estimated 3.0 MW at full load (442 MW) and 0.61 MW at low load (165 MW). This represents a potential improvement in NPHR of 71 Btu/kWh, or 0.71%, at full load and 14 Btu/kWh, or 0.14%, at low load.

Note that several factors can influence whether the auxiliary power benefit at low load is higher or lower than at full load such as the combustion air and flue gas pressures fans are subject to throughout the load range, how much the leakage percentage increases at low load when air heater seal clearances are different than at full load, and others. Black & Veatch made every attempt possible with the time and information available to properly estimate these auxiliary power improvements, but as it was mentioned previously, additional testing is recommended to confirm air heater leakage at various loads.

Current vertical-shaft Ljungstrom regenerative type air heater designs with duplex sealing systems and movable sector plates that have been installed in recently constructed pulverized coal power plants are typically guaranteed for leakages around 6% and typically test at 4.5% to 5% leakage when new. Additionally, by comparison with another unit in the LG&E and KU system: the estimated air heater leakage for Trimble County Unit 2 for this fleetwide LG&E and KU efficiency study is currently at 5.5% and Black & Veatch understands that those air heaters are not equipped with movable sector plates. Therefore, the 8.0% and 6.0% air heater leakages that Black & Veatch has estimated, depending on the upgrades chosen, with the existing Brown Unit 3 air heaters is expected to be attainable for air heaters that undergo a consistent maintenance schedule.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial as the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule of thumb, for every 40 °F decrease in air heater gas outlet temperature, a 1.0% increase in boiler efficiency can be expected. The reduction in leakage discussed previously is expected to increase the measured average air heater gas outlet temperature by about 15 to 20 °F. Currently it is between 295 to 315 °F depending on load and time of year and would go up to around 310 to 330 °F. But this increase will not impact boiler efficiency as the air heater no-leak gas outlet temperature will remain the same (all leakage is assumed to occur on the cold side). An air heater basket design that could lower the no-leak temperature by 20 °F would allow measured air heater gas outlet temperatures to decrease back down to current levels while providing an increase in boiler efficiency by about 0.5%. However, with the lower range of these temperatures already too close to the estimated acid dew point (reductions due to sorbent injection not included in estimation), Black & Veatch does not recommend retrofitting an air heater basket design that would lower the current air heater gas outlet temperatures (provide increased heat transfer). It is assumed that the air preheat system is already operating close to full capacity during low load operating in the colder months of the year. Therefore, if the duplex sealing option is chosen which requires new baskets, it is recommended that the new baskets have the same heat transfer capability as the existing baskets. Also, any improvement in air heater performance (transferring more energy to combustion air by further lowering gas out temperatures) would be offset by additional energy sent to the air preheat coils to maintain an appropriate ACET and/or air heater gas outlet temperatures above the acid dew point.

An internal air heater conditional assessment should also be made to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR. Note that the process of refurbishing, sometimes called blueprinting, a unit's existing air heaters such as realigning components that are out-of-round and/or out-of-plane and replacing worn out components can show significant improvements.

### 3.3.2 Draft System Ductwork and Equipment Casing

The ductwork system can be divided among the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health. The combustion air ductwork system will operate at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakage will increase the duty of the combustion air fans resulting in an increase in the combustion air fan auxiliary load, thus negatively impacting the units NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas induced draft fans resulting in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the units NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Information available to assess the flue gas duct work leakage was referenced from ASSET360 data and included in the discussion on the air heaters (leakage through the SCR, PJFF, and surrounding ductwork) where it was used to help determine the estimated air heater leakage. For the SCR it was assumed to be 1.0% and for the PJFF and surrounding ductwork it was estimated to be 2.1% as previously discussed. Combustion air ductwork leakage was not evaluated as this leakage cannot typically be determined using plant operating data. Additionally, deterioration on combustion air ductwork over time is typically minimal due to it being essentially void of acid gases. However, similar to flue gas ductwork, combustion air ductwork should be inspected on a regular basis and if there are obvious areas where combustion air ductwork is leaking, including expansion joints, these areas should be repaired to minimize additional auxiliary power consumption.

In-order to determine the overall cost associated with improving the ductwork leakage rates field examinations and test must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator to locate and catalog the leaks would be required. Estimates of leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e. areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas induced draft fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

For both the SCR, PJFF, and surrounding ductwork, the leakage percentages are considered to be very reasonable of for the age this equipment and Black & Veatch has not assessed any NPHR impacts regarding reducing air in-leakage for that equipment. However, Black & Veatch still encourages LG&E and KU to consider performing the activities described in this section to continue to find draft system leakage points and repair them when possible.

A summary of the evaluated air heater and draft system leakage control projects are summarized here.

***Air Heater Retrofit of Movable Sector Plates + Seal Replacement***

For reducing air heater leakage to 8%

| | |
|---|---|
| Total Installed capital cost: | $850,000 |
| Auxiliary Power Reduction: | Full load (442 MW gross): 2.5 MW |
| | Low load (165 MW gross): 0.50 MW |
| Heat Rate (efficiency) improvement: | 0.36% |

***Air Heater Retrofit of Duplex Sealing System with New Baskets (same heat transfer capability) and Movable Sector Plates + Seal Replacement***

For reducing air heater leakage to 6%

| | |
|---|---|
| Total Installed capital cost: | $3.8 million |
| Auxiliary Power Reduction: | Full load (442 MW gross): 3.0 MW |
| | Low load (165 MW gross): 0.61 MW |
| Heat Rate (efficiency) improvement: | 0.43% |

## 3.4 VARIABLE FREQUENCY DRIVE UPGRADES

Variable-frequency drives (VFD) function by controlling electric motor speed by converting incoming constant frequency power to variable frequency, using pulse width modulation. VFD upgrades for large electrically driven rotating equipment provide many co-benefits, the largest one of which is improved part-load efficiency and performance. This benefit is greatest at low load, and the more part load and unit cycling that is done, the greater the benefit.

In addition to the reduced auxiliary power consumption, other benefits that are gained from the installation of VFDs on rotating equipment are as follows:

- Reduced noise levels around the equipment
- Lower in-rush current during startups
- Decreased wear on existing auxiliary power equipment

Disadvantages of the installation of VFDs include the high capital cost plus a minimal amount of increased electrical equipment maintenance associated with the VFD system.

Output power signal quality and reliability of VFD equipment has increased significantly in the last 10 to 15 years, to the point that equipment from some manufacturers are approved for use, and have been installed, in nuclear power plants for critical equipment such as reactor coolant and recirculation pumps. Part of this increased reliability comes from the development of technology to allow the VFD equipment to remain in operation if one or multiple IGBT power cells fail by automatically bypassing the bad cell, or cell(s), until an outage when repairs can be made. Additionally, output power signals meet IEEE 519 1992 requirements eliminating the need for harmonic filters.

VFD installation typically requires about two months of total pre-outage work, with a 1-week outage (per device) for the final tie-in. To support installation of the VFDs, the following changes are necessary:

- Replace existing rotating equipment coupling with resilient elastomeric block-shaft couplings to ensure no electrically induced torsional forces are transferred to the fan rotor. This means the existing equipment must be de-coupled from the motor, and then realigned with the new coupling.
- Upgrades to the lube oil system as necessary.
- New VFD enclosure foundations.
- New VFD enclosures and heat exchangers.
- Replace the power supply cables between existing switchgear to the new VFD enclosure. Install new cables from the VFD enclosure to the motor.
- For smaller units, the VFD control enclosure and cabinets will also be smaller with reduced pre-outage time requirements. Note that the air cooled VFD equipment can further reduce equipment installation and maintenance costs.

The rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas (primary air, forced draft, and induced draft fans).

### 3.4.1 Boiler Feed Pumps

The Brown Unit 3 boiler feed pumps are turbine driven feed pumps which already provide high efficiency variable speed capability. The installation of VFD systems on the boiler feed pumps will therefore not be evaluated further.

### 3.4.2 Circulating Water Pumps

The circulating water system includes two 50% capacity horizontal circulating water pumps driven by 2,000-horsepower motors. The Brown Unit 3 operating data, taken from ASSET360 during July-August of 2018 and January-February of 2019, indicated that the unit was off-line approximately 43% of the time during the data collection period. Considering only those time periods when the ASSET360 data showed generation, the unit operated between 20% load and 40% load for approximately 62% of the time, with the unit operating over 80% load for only 3% of the time. The ASSET360 operating data may not be representative of the normal operating load profile for the unit due to operating issues encountered during the data collection period. Although the operating load profile indicated by the ASSET360 data may not be representative of the normal Brown Unit 3 load profile, the addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow during periods of part load operation or during colder months. However, variations in pump speed and circulating water flow can have a significant impact on condenser backpressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser backpressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e. circulating water pumps and cooling tower fans). These studies have shown that, for most of the time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser backpressure possible. This operating scenario by and large provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser backpressure.

As an example, for every 0.1 in Hg increase in condenser back pressure for Brown Unit 3, the turbine generator output will decrease by about 0.5 to 1.0 MW. Decreasing circulating water flow by 5% will decrease the circulating water pump auxiliary load by about 0.35 to 0.45 MW and the condenser back pressure is expected to increase by about 0.2 in Hg or more, especially during the warmer months creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and/or flow rates can be estimated utilizing the pump affinity laws. The following table summarizes the rated circulating water pump design conditions, as provided in the Brown Unit 3 documentation, and the reduced operating pump brake horsepower at a 1% and a 5% reduction in circulating water flow rate per pump. Based on Brown Unit 3 correspondence and documentation, it appears that the pumps actually tested at a slightly higher design flow than originally specified. The rated operating conditions included in Table 3-4 are based on a June 11, 1970 letter from Sargent & Lundy to the Worthington Corporation and the as-tested pump curves.

**Table 3-3 Predicted Circulating Water Pump Operating Conditions at Reduced Flows**

| | RATED OPERATING CONDITIONS | 1% REDUCED FLOW OPERATING CONDITIONS | 5% REDUCED FLOW OPERATING CONDITIONS |
|---|---|---|---|
| Flow, gpm | 86,500 | 85,635 | 82,175 |
| Total head, ft | 75 | 73.5 | 68 |
| Pump brake horsepower, hp | 1,855 | 1,800 | 1,590 |
| Pump speed, rpm | 400 | 396 | 380 |
| Note: The above operating data is for one of two (2x50%) circulating water pumps. | | | |

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection systems on most of the LG&E and KU units being evaluated for this study involve the use of cooling towers (mechanical or natural draft), the installation of VFD systems on circulating water pumps will not be evaluated further.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 3 circulating water pumps is $2,100,000.

### 3.4.3 Cooling Tower Fans

Cycle heat rejection is via two six (6) cell mechanical draft cooling towers each with six cooling tower fans. Each cooling tower fan is driven by a 150-horsepower motor with a variable frequency drive system. With the cooling tower fans already begin equipped with variable speed drives, the fans will not be investigated further.

### 3.4.4 Large Draft Fans

Brown Unit 3 has a unique arrangement for the FD and ID fans. Due to the unit originally being a forced draft unit, the FD fans are very large for the service they are required to provide for and they are equipped with hydrodynamic fluid drives that allow the fans to control flow through variable speed. Even though the FD fans control flow through variable speed, Black & Veatch has still seen potential significant benefits retrofitting these types of large draft fans with VFDs. the ID fans are equipped with inlet vanes for flow control and also have two speed motors. Black & Veatch also expects there to be potential for a significant auxiliary power consumption benefit retrofitting these with VFDs.

Based on available information and operating data the Brown Unit 3 FD fan auxiliary power consumption benefit is estimated to be 2.1 MW for both fans at full load (442 MW) and 0.60 MW at low load (165 MW). See Figure 3-2, illustrating the current FD fan operation with variable speed fluid drives and future variable speed operation with VFDs. These fans are well oversized for the service that is required of them making them a very good candidate for variable speed operation with VFDs, even with the originally equipped variable speed fluid drives. Additionally, due to these fans being so oversized Black &Veatch as included an installed price for VFD systems that are rated for about 2,000 hp per fan versus the full motor rating (estimated to be about 4,500 hp) as this unit is now a balanced draft unit and the full motor rating is no longer needed. Further optimization of this price and VFD hp rating can take place during detailed design.

The evaluated impacts of this project are as follows:

***VFD Deployment for FD Fans***

| | |
|---|---|
| Total Installed capital cost: | $2.03 million for both fans |
| Auxiliary Power Reduction: | Full load (442 MW gross): 2.1 MW |
| | Low load (165 MW gross): 0.60 MW |
| Heat Rate (efficiency) improvement: | 0.32% |

Estimated additional annual operations and maintenance cost: $15,000 per unit

The estimated furnish and erect price for a variable frequency drive system for the Brown Unit 3 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, extension shaft between the existing motor and fan, new lube oil skids, new power cabling and any new raceway required, demolition of the existing variable speed fluid drive, engineering, installation, and contingency. Also note that if there is limited available space immediately around the rotating equipment, this will not affect the installation of VFD systems as the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

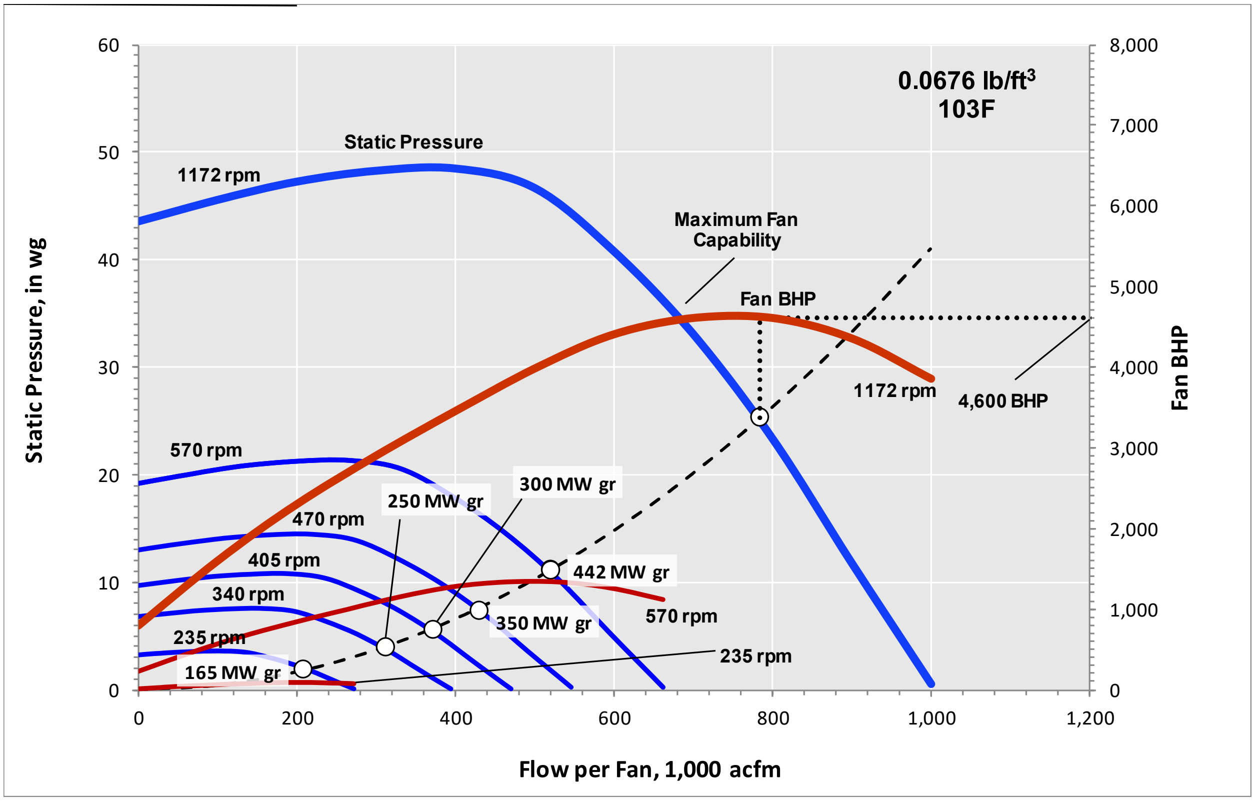



**Figure 3-2 Brown Unit 3 FD Fan Operation – Variable Speed Control**

Based on available information and operating data the Brown Unit 3 ID fan auxiliary power consumption benefit is estimated to be 4.1 MW for both fans at full load (high-speed operation) (442 MW) and 3.2 MW at low load (low-speed operation) (165 MW). See Figures 3-3 through 3-5, illustrating the current ID fan operation with inlet vane control and future variable speed operation with VFDs. Note that there are two charts for inlet vane control due to the two-speed motors. Based on operating data, the ID fans are operated at high speed (891 rpm) during full load operation (Figure 3-3), although based on Figure 3-4 it seems that operating the ID fans at low-speed when at full load is possible while still allowing for some margin and controllability. If operators would be comfortable with this mode of operation, there is some potential for auxiliary power savings for essentially zero capital investment. If the ID fans were operated at full load on the low speed setting the auxiliary power savings is estimated to be 4.2 MW versus operating at high speed. Note that this would essentially negate the benefit of adding variable speed capability with VFD systems during full load operation. During operation at lower loads a VFD system will still provide significant benefits. However, Black & Veatch understands that there could be reasons for not operating in this manner such as the potential for limited furnace pressure controllability. Further investigation with plant personnel is recommended to understand whether the existing ID fans could be operated on low speed at full load as is done at other loads. The ID fans are operated at low speed (714 rpm) during operation at lower loads (Figure 3-4). The different fan efficiencies at these two different speeds has been accounted for and the benefit of lower auxiliary power consumption at lower loads is based on comparing the existing fans operating at low speed versus installing VFD systems. These fans are well oversized for the service that is required of them making them a very good candidate for variable speed operation with VFDs.

The evaluated impacts of this project are as follows:

***VFD Deployment for ID Fans***

| | |
|---|---|
| Total Installed capital cost: | $5.65 million for both fans |
| Auxiliary Power Reduction: | Full load (442 MW gross): 4.1 MW |
| | Low load (165 MW gross): 3.2 MW |
| Heat Rate (efficiency) improvement: | 0.86% |

Estimated additional annual operations and maintenance cost: $15,000 per unit

The estimated furnish and erect price for a variable frequency drive system for the Brown Unit 3 ID fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. Note that Black & Veatch has installed VFDs on two-speed motors in the past and expects that these ID fan motors will work well with VFDs as well. If VFDs are retrofitted to these fans, the approach will be to leave the motor speed switches in the high-speed setting permanently and allow the VFD to then control speed (with inlet vanes fully open as well). Also note that if there is limited available space immediately around the rotating equipment, this will not affect the installation of VFD systems as the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

(Note that unlike other units studied across the LG&E and KU fleet, Black & Veatch was unable to add brake horsepower curves to the fan graphs as the baseline fan brake horsepower curves were not available in the plant data that was supplied for this study).

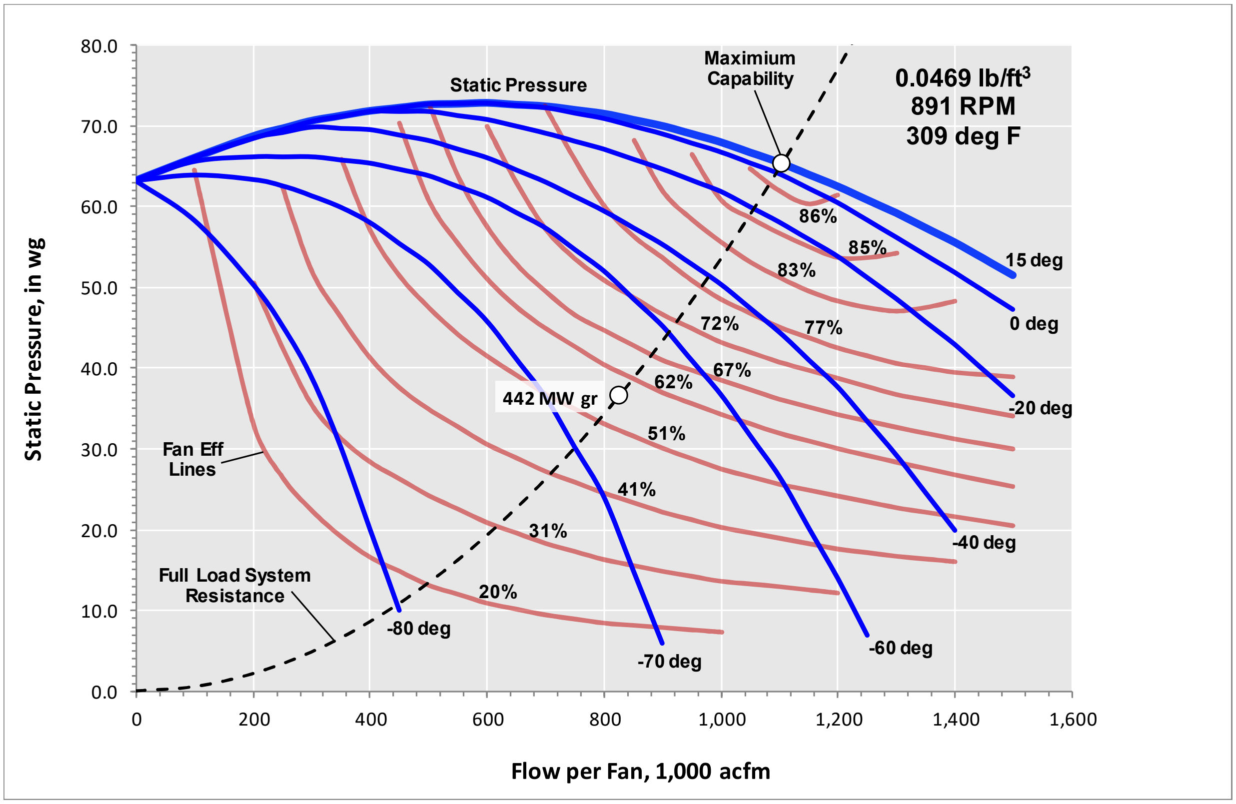



**Figure 3-3 Brown Unit 3 ID Fan Operation – Inlet Vane Control at High Speed (891 rpm)**

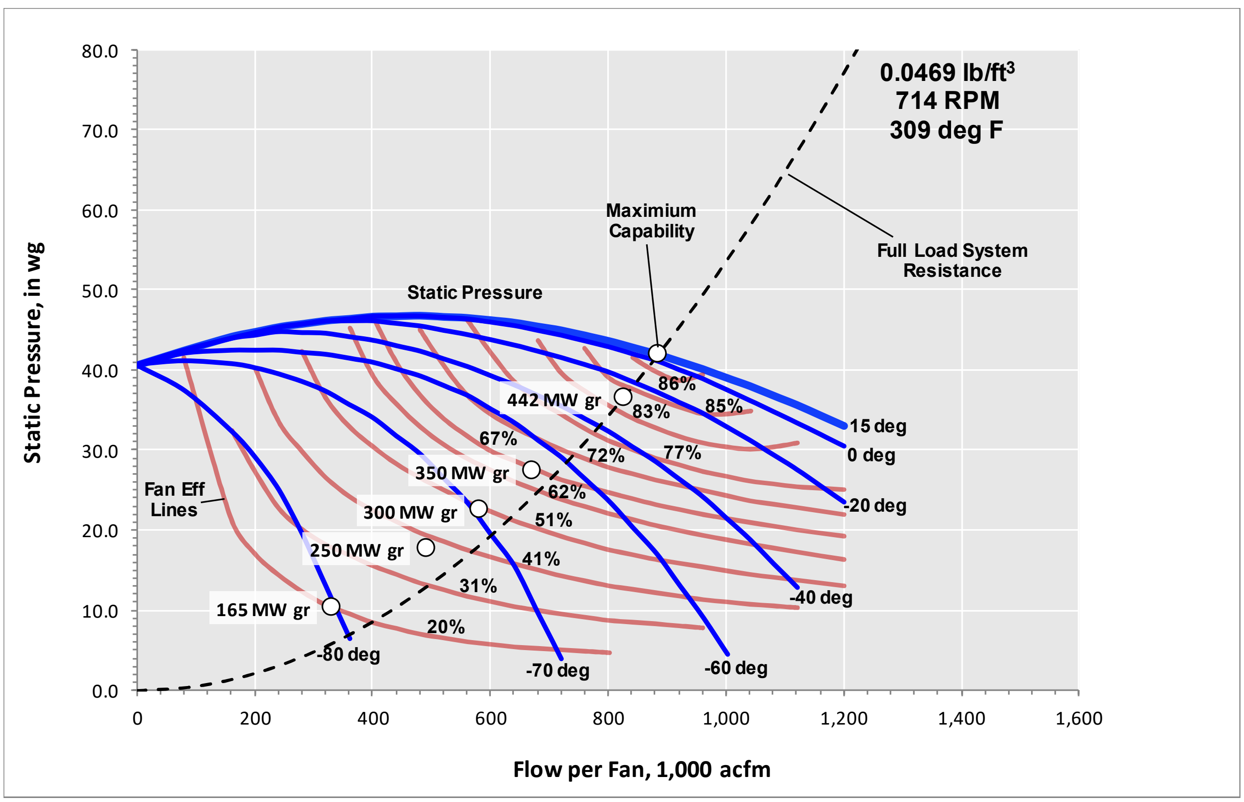



**Figure 3-4 Brown Unit 3 ID Fan Operation – Inlet Vane Control at Low Speed (714 rpm)**

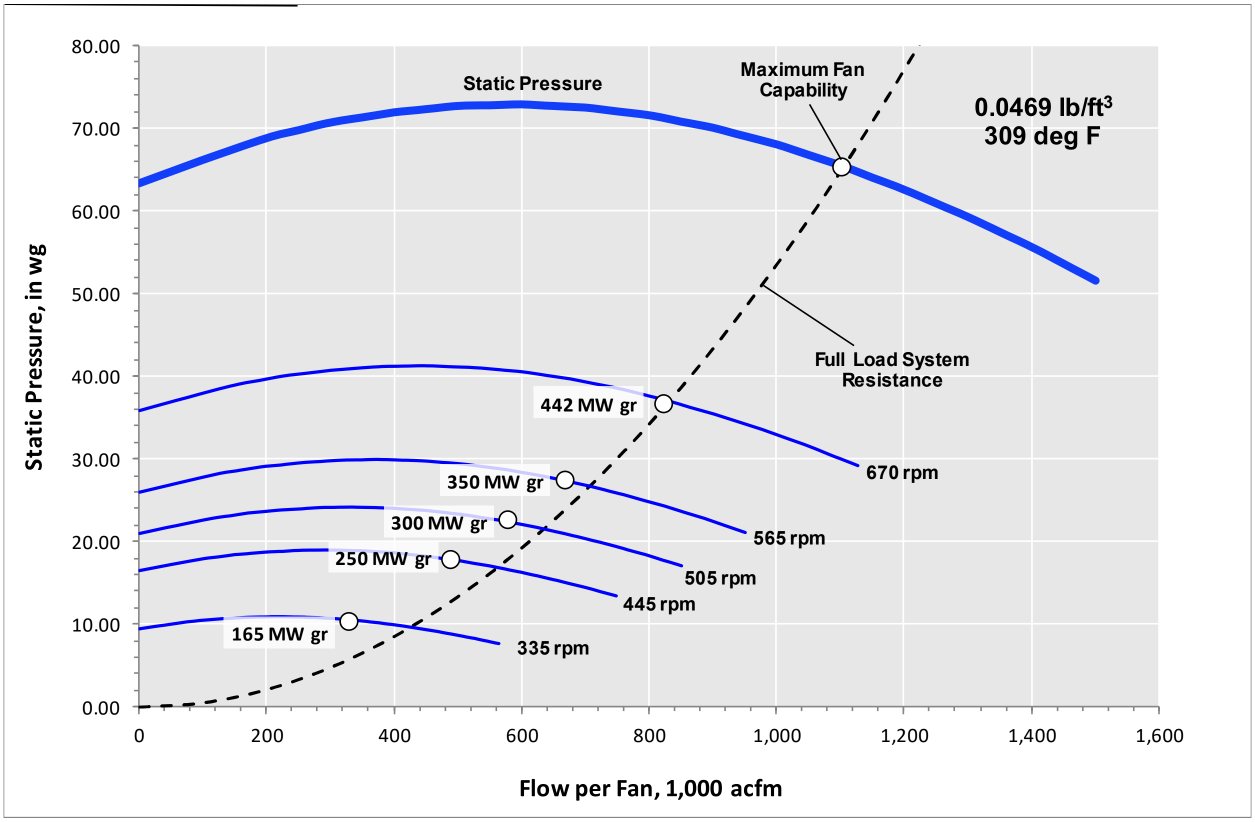



**Figure 3-5** **Brown Unit 3 ID Fan Operation – Variable Speed with VFDs**

## 3.5 NEURAL NETWORK DEPLOYMENT

The purpose of this project would be to tune the system to allow for the reduction of boiler outlet oxygen concentration without increasing nitrogen oxides ($NO_X$) or carbon monoxide (CO) emissions. Adaptive neural net systems have the greatest affect when controlling air flow and fuel mixtures down to a fine level. The full benefits are only realized if the plant has adequate feedback signals to allow the neural net to sense changes made to the available controls. For instance, individual fuel and air measurements and controls at each burner provide tremendous levers for a neural net system; however, the effect of the levers is reduced if the neural net does not receive feedback about the air and fuel mixture through a grid of CO measurements. The unit does not have the ability to bias individual burners, but there is secondary air damper control by level. There is no valid CO indication. Thus, the unit must be restricted to an arbitrary $O_2$ lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Based on Black & Veatch experience, boiler combustion tuning can typically gain 0.25% in boiler efficiency, dependent often on lower $O_2$ concentration. Utilizing the Vista model of Brown Unit 3 and evaluating the impacts of a 0.25%, 0.50%, and 0.75% decrease in excess $O_2$ (not to be confused with the aforementioned 0.25% gain in boiler efficiency), the estimated gains in boiler efficiency and net plant heat rate at full load are, respectively:

- 0.25% Reduction in excess O2: 0.09% gain in boiler efficiency, 0.22% improvement in net plant heat rate
- 0.50% Reduction in excess O2: 0.18% gain in boiler efficiency, 0.43% improvement in net plant heat rate
- 0.75% Reduction in excess O2: 0.27% gain in boiler efficiency, 0.62% improvement in net plant heat rate

Hypothetically, we would tend to assume that a modest reduction in boiler excess oxygen would be possible with appropriate instrumentation, so if the unit could lower boiler outlet oxygen concentration by about 0.25%, then the net plant heat rate improvement would be about 0.22%. The effects on net plant heat rate were not linear, because they varied as a function of auxiliary power changes, as well as changes in steam temperatures which were impacted by reduced excess $O_2$ levels.

| | |
|---|---|
| Total Installed Capital Cost: | $450,000 |
| Heat Rate (efficiency) improvement: | 0.22% |

## 3.6 INTELLIGENT SOOTBLOWING DEPLOYMENT

The purpose of this project would be to reduce the required sootblowing flow, by installing an integrated intelligent sootblower control system. This system would utilize heat flux sensors, hanger strain gauges, and process data to determine the areas needing to be cleaned. By only cleaning the “dirty” areas, sootblowing flow would be reduced and tube life potentially extended.

The plant uses air as the media and has IK and IR sootblowers, but there are currently no heat flux sensors or hanger strain gauges installed. They currently sootblow nightly on load drop, and additional blowing is performed as necessary to control slagging and temperature. In addition to current sootblower operation and maintenance, it’s estimated that an intelligent sootblowing system can reduce sootblowing by approximately 10%.

| | |
|---|---|
| Total Installed Capital Cost: | $350,000 |
| Heat Rate (efficiency) improvement: | 0.03% |

## 3.7 IMPROVED O&M PRACTICES

The purpose of this project would be to improve O&M practices as they pertain to three particular areas of focus. These areas include heat rate improvement training, on-site appraisals for identifying additional heat rate improvements, and improved condenser cleaning strategies.

### 3.7.1 Heat Rate Improvement Training

Black & Veatch conducts Heat Rate Awareness training which covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. The course includes numerous real-life case studies identified thru years of monitoring and diagnostic work. This on-site course is typically 2.5 days and is primarily geared towards operators and engineers.

| | |
|---|---|
| Total Installed capital cost | $15,000/class (could cover multiple units and plants). |
| Heat Rate (efficiency) improvement: | Unknown, although improved O&M practices at peer coal-fired EGUs have claimed to result in net plant heat rate improvements of 0.1-0.5% in the first year of implementation. |

### 3.7.2 On-Site Heat Rate Appraisals

This item which is mentioned as a BSER in the EPA ACE proposal is left open to interpretation and indeed, the EPA was not able to provide suitable guidance for estimated ranges of capital cost or HRI. On-site heat rate appraisals are often conducted via detailed assessment of controllable losses, especially those which can be reduced or eliminated by low-impact operations changes and equipment repairs and upgrades. This assessment utilizes a combination of a review and analysis of historical operations data, interviews with plant operations and maintenance personnel, review of past test and capability reports, a detailed study of the current fuel sources and fuel-related impacts upon the plant, discussions with plant management to understand the plant generation goals and objectives, and a reliability and maintenance history analysis.

Real-world examples of heat rate improvement projects resulting from on-site heat rate appraisals and audits include the following:

- Diagnosis of a cracked feedwater heater partition plate via analysis of online performance data, which resulted in a $12,000 monthly heat rate savings and 0.4 MW capacity improvement.
- Discovery of a failed reheat stop valve by analyzing reheat pressure swings over time, resulting in a $65,000 monthly heat rate improvement and 4 MW capacity improvement.
- An audit of TTD and DCA temperature trends across a feedwater heater train at one power plant found that the highest-pressure feedwater heater emergency drain valve was leaking, with 50% of its flow returning to the condenser, rather than cascading to the next feedwater heater. This failure resulted in a heat rate loss of 53 Btu/kWh (about 0.5%) and a net capacity loss of 2.5 MW.
- Testing of mill dirty-air flows and coal flow balances at one power plant found that by rebalancing the flows on 4 mills to bring the coal and air flow deviation to within +/- 10% (compared to the +/- 30% it formerly operated at), coal unburned carbon

heat losses decreased by 0.5%, which directly translated to a heat rate improvement of 0.5%. Moreover, burner-zone slagging was nearly eliminated by this change, resulting in significantly less use of sootblowing steam in the furnace wall blowers, which resulted in an additional long-term heat rate benefit of 0.1% (and a corresponding improvement in furnace wall tube life).

- Long-term analysis of subtle deviations in feedwater heater extraction lines revealed an internal line had failed, resulting in not only a $15,000 heat rate loss, but the potential for an unplanned outage due to debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found that not only were 7 of the coals unprofitable to burn, burning the worst coal resulted in a heat rate loss of more than 2%. Moreover, this coal was responsible in whole or in part for the majority of the plant de-rates due to high-temperature sodium-based fouling, which cost the unit an additional 1.2% in heat rate on an annual basis due to the increased number of starts and stops from fouling-related outages.
- A long-term analysis of plant CEMs data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending of two different coals to meet the plant $SO_2$ limit, resulting in not only excess use of low-sulfur coal, but a loss of heat rate equating 0.6% on an annual basis.

Heat rate assessment is an ever-moving target, so while there is substantial benefit from a focused heat rate auditing and improvement program, long-term use of some type of performance and O&M monitoring system will provide the best overall heat rate improvement.

### 3.7.3 Improved Condenser Cleaning Strategies

Currently the condenser is manually cleaned at least 1 time per year, typically during a scheduled outage each spring. Installing a ball tube cleaning system is most often effective in maintaining near design levels of tube cleanliness and should reduce the need for more aggressive cleaning. It should also help mitigate condenser backpressure heat rate impacts due to condenser fouling.

Analyzing the past 2-3 years of condenser performance has shown that condenser tube fouling has not been a routine issue. Thus, the improvement from such a system would be inconsistent. For quantification purposes, the current cleanliness issue has caused a 0.3 in. HgA increase in condenser backpressure, which is approximately a 0.6% heat rate impact.

| | |
|---|---|
| Total Installed capital cost: | $500,000 |
| Heat Rate (efficiency) improvement: | 0.60% |

# 4.0 Performance and $CO_2$ Reduction Estimates

High level plant performance estimates were used to estimate the average annual $CO_2$ reduction. These performance benefits are summarized in Appendix B, Tables B-1 and B-2. It should be noted that some projects will have overlapping performance impacts and benefits, such that the overall net benefit for a series of projects considered together will likely differ from the sum of the individual project benefits listed in Tables B-1 and B-2.

The annual $CO_2$ reductions shown in Table B-1 were estimated based on the following plant performance basis and assumed a baseline 70% net capacity factor which was kept constant for all units across the coal generating fleet. Gross and net capacity and the average annual net plant heat rate were provided by the Vista model of Brown Unit 3 and the coal burn rate estimated at 442 MW gross output.

**Table 4-1 Basis for $CO_2$ Reduction Estimates – 70% Net Capacity Factor**

| GROSS/NET CAPACITY (MW) | NET CAPACITY FACTOR (%) | AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)* | FUEL HEAT INPUT (MBTU/Y)* | LBM $CO_2$/ MBTU (HHV)* | ANNUAL $CO_2$ (TONS/Y)* |
|---|---|---|---|---|---|
| 442/404.5 | 70% | 10,536 | 26,766,100 | 202.9 | 2,715,440 |

* Note that this differs from Table 2-1 due to being an annual average value, rather than full load value.

The annual $CO_2$ reductions shown in Table B-2 were estimated based upon a 5-year look ahead net capacity factor estimate that was provided by LG&E and KU. For Brown Unit 3, this net capacity factor estimate was 19.8%. Gross and net capacity were unchanged, although the average annual net plant heat rate did vary due to the difference in the net capacity factor (also provided by the Vista model of Brown Unit 3 and the coal burn rate estimated at 442 MW gross output.)

**Table 4-2 Basis for $CO_2$ Reduction Estimates – 19.8% Net Capacity Factor**

| GROSS/NET CAPACITY (MW) | NET CAPACITY FACTOR (%) | AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH) | FUEL HEAT INPUT (MBTU/Y) | LBM $CO_2$/ MBTU (HHV) | ANNUAL $CO_2$ (TONS/Y) |
|---|---|---|---|---|---|
| 442/404.5 | 19.8% | 10,623 | 7,779,840 | 202.9 | 789,160 |

Where:

Fuel Heat Input [MBtu/y] =

Net Capacity [MW] * 1,000 kW/MW * Capacity Factor [%] * 8,760 h/y * NPHR [Btu/kWh, HHV]/ (1,000,000 Btu/MBtu)

Annual $CO_2$ Production [tons/y] = Fuel Heat Input [MBtu/y] * $CO_2$ Production Rate [lbm/MBtu of Fuel Burned]/ (2,000 lbm/ ton)

# 5.0 Capital Cost Estimates

High level capital cost estimates were developed for each alternative and are detailed with each heat rate improvement (HRI) project in Section 3. These estimates are summarized in Appendix B, Tables B-1 and B-2 and are based on the information available and should be considered preliminary for comparative purposes. The estimates are on an overnight basis (exclusive of escalation). The estimates represent the total capital requirement for each project assuming a turnkey Engineer, Procure, and Construct (EPC) project execution strategy. Pricing was based on similar project pricing or Black & Veatch internal database. Black & Veatch has not developed preliminary equipment sizing or layouts to determine the feasibility of adding the proposed equipment or performing the modifications that will be required to support their installation. More detailed evaluations will be required to verify, refine, and confirm the viability of any of the proposed projects which require equipment modification or additional area.

# 6.0 Project Risk Considerations

Factors which influence the ability to maintain power plant efficiency and corresponding $CO_2$ emissions reductions on an annual basis are discussed below.

## 6.1 EFFICIENCY DIFFERENCES DUE TO OPERATING PROFILE

Efficiency is significantly affected when plants operate under off-design conditions, particularly part-load operation or with frequent starts. The future operating characteristics of Brown Unit 3 can have a significant impact on the ability to achieve the expected efficiency gains and associated reduced $CO_2$ emissions.

### 6.1.1 Operating Load and Load Factor

Plants which operate with a low average output will have lower efficiency compared to their full-load design efficiency. Load or capacity factor describes the plant output over a period of time relative to the potential maximum; it depends on both running time at a given load and the operating load. Therefore, annual variation in both operating load and load factor can alter the $CO_2$ emissions as well as the benefit of capital projects intended to reduce plant emissions. Variation in the unit load factor can significantly impact the annual $CO_2$ emissions for a given generation rate.

Capital projects that may offer benefit in reducing outage duration or frequency may also see some benefit mitigated. For example, a plant may be able to extend the time between major overhauls and shorten the time required for a major overhaul of the steam turbine due to improved design. However, this could increase the hours the plant may run in a year and could increase the annual $CO_2$ emissions. Plant generation may be limited to avoid exceeding annual $CO_2$ emissions rates, negating some of the potential benefit of the upgrade.

### 6.1.2 Transient Operation

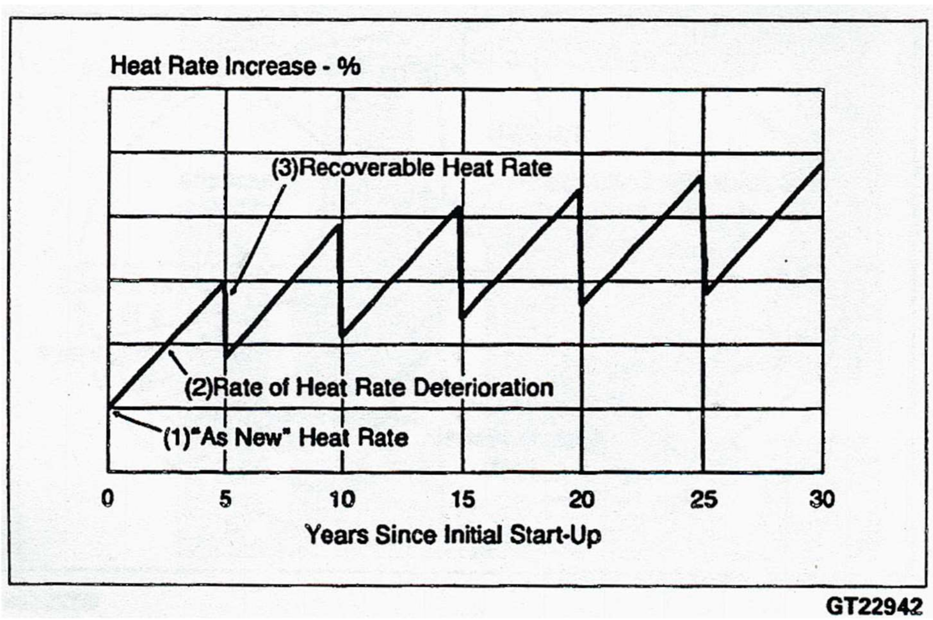
The greater the number of transients from steady state operating conditions that the plant experiences, the greater the impact to annual efficiency. During each of these transients, the plant will not be operating at peak performance. The influence of increasing renewable energy can affect the frequency of transient operation. Operation in frequency response mode, where steam flow and boiler firing fluctuate to regulate system frequency, can lead to more transients. Other situations may require frequent load changes, notably in response to power system constraints or power market pricing.

### 6.1.3 Plant Starts

Frequent shutdowns incur significant off-load energy losses, particularly during subsequent plant startup. Power plants operating in volatile or competitive markets, or operating as marginal providers of power, may be required to shut down frequently. This can also lead to deterioration in equipment condition which will further affect annual plant efficiency and increase $CO_2$ emissions.

## 6.2 DETERIORATION

Figure 6-1 illustrates the characteristic of performance deterioration that the steam turbine can be expected to experience between major overhauls. In addition, the ability of the steam turbine to economically recover from any deterioration in performance during a regularly scheduled maintenance overhaul is also illustrated. Any steam turbine retrofit is expected to experience a similar pattern of increasing deterioration, where increasingly a portion of this deterioration is not viably recovered, even following a major overhaul. Turbine suppliers recognize the importance of sustained efficiency and work to incorporate features that result in superior sustained efficiency. The degree to which deterioration can be minimized by new designs is in large part dependent on the current design and feasible proven options. The ability of the steam turbine to sustain efficiency is a significant factor in achieving year after year $CO_2$ reduction.




**Source: Steam Turbine Sustained Efficiency, GER-3750C**

**Figure 6-1 Steam Turbine Generator Heat Rate Change Over Time**

Other plant equipment is also expected to see performance deterioration over the operating life after capital projects are implemented. The degree of deterioration and the rate at which it occurs is difficult to predict and presents a risk to the longer-term ability of the plants to sustain their efficiency gains.

## 6.3 PLANT MAINTENANCE

As well as ensuring plant availability, a key requirement of plant maintenance is to maintain peak operating efficiency. Improved maintenance and component replacement and upgrading can reduce energy losses.

Any poorly performing auxiliary equipment or individual components which affect performance will also contribute to the overall deterioration of plant performance over time, compounding the effects of deterioration in major components, such as the steam turbine. While not an intended outcome, plant upgrades can also result in increased maintenance if the expected improvements cannot be not achieved without increased or more complicated plant maintenance. Table B-1 and B-2 include an order of magnitude rating of comparative operating and maintenance cost impact associated with each of the given projects.

## 6.4 FUEL QUALITY IMPACTS

Variation in fuel quality can have a significant impact on the boiler efficiency. Reduced boiler efficiency will increase the required fuel heat input for a given generation which will increase $CO_2$ emissions. Variation in fuel composition can also have an effect on the lbm of $CO_2$ emission/MBtu of fuel burned.

## 6.5 AMBIENT CONDITIONS

Variation in ambient conditions can affect the condenser operating pressure and the resulting steam turbine output. In particular, higher wet bulb temperatures can have a significant impact on plant heat rate. Variation in annual average turbine back-pressure due to wet bulb will affect the expected benefits of several of the heat rejection and steam turbine capital improvement projects.

# Appendix A. Abbreviations and Acronyms

| | |
|---|---|
| °F | Degrees Fahrenheit |
| 3D | Three Dimensional |
| ACE | Affordable Clean Energy (Plan) |
| ADSP | Advanced Design Steam Path |
| AQCS | Air Quality Control System |
| ASSET360 | A comprehensive remote monitoring, diagnostic, and predictive platform that is utilized throughout LG&E and KU's coal units. |
| B&W | Babcock & Wilcox |
| BFP | Boiler Feed Pump |
| BFPT | Boiler Feed Pump Turbine |
| BHP | Brake Horsepower |
| BSER | Best System of Emission Reduction |
| Btu | British Thermal Unit |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| CPP | Clean Power Plan |
| Cu-Ni | Copper-Nickel |
| EGU | Electrical Generating Unit |
| EPA | United States Environmental Protection Agency |
| ESP | Electrostatic Precipitator |
| FD | Forced Draft |
| gpm | Gallons per minute |
| h | Hour |
| HEI | Heat Exchange Institute |
| HHV | Higher Heating Value |
| hp | Horsepower |
| HP | High Pressure |
| ID | Induced Draft |
| IGBT | Insulation – Gate Bipolar Transistor |
| in. HgA | Inches of Mercury – Absolute |
| IP | Intermediate Pressure |
| kW | Kilowatt |
| kWh | Kilowatt hour |
| lbm | Pound |
| LED | Light Emitting Diode |
| LP | Low Pressure |

| | |
|---|---|
| LSB | Last Stage Bucket or Blade |
| MBtu | Million British Thermal Units |
| MW | Megawatt |
| MWh | Megawatt Hour |
| NDE | Non-Destructive Examination |
| $NO_x$ | Nitrous Oxides |
| NPHR | Net Plant Heat Rate |
| OEM | Original Equipment Manufacturer |
| OPM | On-Line Performance Monitor |
| PA | Primary Air |
| PJFF | Pulse Jet Fabric Filter |
| psig | Pounds per Square Inch – Gauge |
| psid | Pounds per Square Inch – Differential |
| PVC | Poly Vinyl Chloride |
| RH | Relative Humidity |
| $SO_2$ | Sulfur Dioxide |
| STG | Steam Turbine Generator |
| TC2F | Tandem-Compound, Two-Flow |
| TTD | Terminal Temperature Difference |
| V | Volt |
| VFD | Variable Frequency Drive |
| Vista | The EPRI Vista fuel quality impact analysis program, which is used to model all of the LG&E and KU coal units. |
| VSC | Variable Speed Coupling |
| WBT | Wet Bulb Temperature |
| y | Year |

# Appendix B. Capital Cost and Performance Estimates

Table B-1 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBTU/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Steam Turbine | IP/HP upgrades | 16,260 | 1.25 | 131.7 | 334,576 | 33,943 | 479.0 | No change |
| Steam Turbine | Full steam path upgrades | 27,910 | 2.00 | 210.7 | 535,322 | 54,309 | 513.9 | No change |
| Economizer | Minor redesign with additional tube passes | 1,100 | 0.25 | 26.3 | 66,915 | 6,789 | 162.0 | No change |
| Air Heater/Duct Leakage | Air Heater Retrofit of a Leakage Control System + Seal Replacement | 850 | 0.36 | 37.9 | 96,358 | 9,776 | 87.0 | Low |
| Air Heater/Duct Leakage | Air Heater Duplex Sealing System with New Baskets and Movable Sector Plates + Seal Replacement | 3,800 | 0.43 | 45.3 | 115,094 | 11,676 | 325.4 | Low |
| Variable Frequency Drive (VFD) Upgrades | Circulating Water Pumps | 2,100 | 0.00 | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Cooling Tower Fans | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Primary Air Fans | N/A | N/A | N/A | N/A | N/A | N/A | Low |
| Variable Frequency Drive (VFD) Upgrades | Forced Draft Fans | 2,030 | 0.31 | 32.7 | 82,975 | 8,418 | 241.2 | Low |
| Variable Frequency Drive (VFD) Upgrades | Induced Draft Fans | 5,650 | 0.86 | 90.6 | 230,188 | 23,353 | N/A | Low |
| Neural Network | Deployment of a neural network for combustion control and boiler excess air reduction | 450 | 0.22 | 23.2 | 58,885 | 5,974 | 75.3 | Low/Med |
| Intelligent Soot Blowing (ISB) | Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate | 350 | 0.03 | 3.2 | 8,030 | 815 | 430 | Low |

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBTU/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Improved O&M Practices | Heat rate improvement training | 15 | 0.30 | 31.6 | 80,298 | 8,146 | 1.8 | Low |
| Improved O&M Practices | Improved Condenser Cleaning Strategies | 500 | 0.60 | 63.2 | 160,597 | 16,293 | 30.7 | Low |
| Improved O&M Practices | On-site heat rate appraisals | N/A | N/A | N/A | N/A | N/A | N/A | Low |

**Table B-2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits (19.8% NCF)**

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBTU/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Steam Turbine | IP/HP upgrades | 16,260 | 1.25 | 132.8 | 97,248 | 9,865 | 1648.3 | No change |
| Steam Turbine | Full steam path upgrades | 27,910 | 2.00 | 212.5 | 155,597 | 15,783 | 1768.3 | No change |
| Economizer | Minor redesign with additional tube passes | 1,100 | 0.25 | 26.6 | 19,450 | 1,973 | 557.6 | No change |
| Air Heater/Duct Leakage | Air Heater Retrofit of a Leakage Control System + Seal Replacement | 850 | 0.36 | 38.2 | 28,007 | 2,841 | 299.2 | Low |
| Air Heater/Duct Leakage | Air Heater Duplex Sealing System with New Baskets and Movable Sector Plates + Seal Replacement | 3,800 | 0.43 | 45.7 | 33,453 | 3,393 | 1,119.8 | Low |
| Variable Frequency Drive (VFD) Upgrades | Circulating Water Pumps | 2,100 | 0.00 | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Cooling Tower Fans | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Primary Air Fans | N/A | N/A | N/A | N/A | N/A | N/A | Low |
| Variable Frequency Drive (VFD) Upgrades | Forced Draft Fans | 2,030 | 0.31 | 32.9 | 24,118 | 2,446 | 829.8 | Low |
| Variable Frequency Drive (VFD) Upgrades | Induced Draft Fans | 5,650 | 0.86 | 91.4 | 66,907 | 6,787 | N/A | Low |
| Neural Network | Deployment of a neural network for combustion control and boiler excess air reduction | 450 | 0.22 | 23.4 | 17,116 | 1,736 | 259.2 | Low/Med |
| Intelligent Soot Blowing (ISB) | Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate | 350 | 0.03 | 3.2 | 2,334 | 237 | 1,478 | Low |

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBTU/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Improved O&M Practices | Heat rate improvement training | 15 | 0.30 | 31.9 | 23,340 | 2,367 | 6.3 | Low |
| Improved O&M Practices | Improved Condenser Cleaning Strategies | 500 | 0.60 | 63.7 | 46,679 | 4,735 | 105.6 | Low |
| Improved O&M Practices | On-site heat rate appraisals | N/A | N/A | N/A | N/A | N/A | N/A | Low |