FINAL

RESPONSES TO EPA PROPOSED ACE GUIDELINES

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Table of Contents

LIST OF TABLES

LIST OF FIGURES

Glossary of Terms

CFB	Circulating fluidized bed combustion.
DERATE	A reduction in unit output. Derates are reported in terms of percent (%) of peak load or in terms of net power (MW).
EAF – EQUIVALENT AVAILABILITY FACTOR	A measure indicating the amount of energy a unit is available to produce over a period of time, relative to the capacity of the unit.
ESP – ELECTROSTATIC PRECIPITATOR	A particulate removal device which uses an electrostatic field as a means of removing particulate matter from a flue gas stream.
FBR – FUEL BURN RATE	The rate at which fuel must be input to a unit to sustain stable load.
NPHR – NET PLANT HEAT RATE	A measure of efficiency comparing the thermal energy required, in terms of GJ or Btu, to produce 1 kWh of net electrical energy.
PC	Pulverized coal combustion.
VFD	Variable-frequency drive.

1.0 Advisory to NRECA on EPA ACE Proposal

1.1 INTRODUCTION

The National Rural Electric Cooperative Association (NRECA) has asked Black & Veatch to respond to specific questions addressing issues raised in its proposed 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. Affordable Clean Energy (ACE) rule)." In each case Black & Veatch discussed the questions asked by the NRECA in-house and relied upon their experience from past and current project work and technical research.

1.2 THE HEAT RATE IMPROVEMENT PROJECTS

1.2.1 Does the list of 7 candidate HRI technologies and practices contain the correct items?

In Table 1 of the proposed rule, Black and Veatch finds the following 7 technologies, equipment upgrades, and operating and maintenance practices called out by the Environmental Protection Agency (EPA) as being the ''most impactful'' HRI measures that they propose as their best system of emission reduction (BSER) for existing coal-fired electrical generating units (EGUs).

Table 1-1 HRI Technologies (pg. 44757)

TABLE 1—SUMMARY OF MOST IMPACTFUL HRI MEASURES AND RANGE OF THEIR HRI POTENTIAL (%) BY EGU SIZE

HRI measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved O&M Practices	Can range from 0 to >2.0% depending on the unit's historical O&M practices.					

Overall, the candidate technologies the EPA proposes to include within ACE seem appropriate. While a variety of efficiency improvements are always important to consider, the return on investment is not easily achieved. Also, the applicability of a specific menu item regarding cost effectiveness and heat rate improvement requires a case-by-case specific unit analysis.

We note that this table contains menu items that are specific and yet can be somewhat broad in application. For example, "variable frequency drives" have a variety of potential applications at a coal-fired EGU with a variety of potential payback periods and cost/benefit structures. In one study conducted by Black & Veatch on behalf of a coal-fired EGU with more than 2 GWe of net capacity, the difference in the benefit from variable frequency drives ranged from $57,000/Btu/kWh for circulating water pumps, to $340,000/Btu/kWh for primary air fan motors.

Another example – "neural network/intelligent sootblowers" also has a wide range of costs depending on existing unit configuration. Intelligent sootblowing is a relatively straightforward retrofit onto an existing coal-fired EGU. However, the merits of intelligent sootblowing may not be proportional to their expense for units if it also requires the installation of the underlying neural network system in order to function. Further, many units in the United States have already developed comprehensive sootblowing and/or water cleaning programs which provide high performance with reasonable O&M costs. Still many other units do not suffer from significant deposition of slag on furnace water walls, or fouling or ash deposits on convective tube surfaces. For these reasons, the installation of neural networks/intelligent sootblowers may not be possible or warranted depending on existing unit configuration or characteristics.

These examples emphasize the need to examine the specific applicability of each menu item on a unit by unit basis.

1.2.2 Are all 7 candidate HRI technologies broadly applicable?

With some exceptions, the technologies found in Table 1 of the proposed rule could be applied at coal-fired EGUs. The appropriateness of any one item to any individual coal-fired EGU must be viewed in light of already applied heat rate improvements related to each one of these 7 potential improvement areas, and considering planned economic remaining useful life, anticipated utilization, and other unit relevant specific factors.

1.2.3 Does the selection of a gross or net basis for the performance standard invalidate any technologies?

The primary difference between the two can be summarized by how one treats station service (auxiliary power) in their generation demand profile. Take for example the case of a unit with the following characteristics:

- Gross output: 400 MW
- Net output: 370 MW
- Net turbine heat rate: 8,000 Btu/kWh
- Boiler efficiency: 88%

The net plant heat rate (NPHR) for this unit would be:

NPHR = 8,000 / ((88/100)*(370/400)) = 9,828 Btu/kWh

And the gross plant heat rate (GPHR) for this unit would be:

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

Now if we assume that a plant deploys variable frequency drives (VFDs) for its main fans and reduces the station service by 2 MW, then the net generation increases at the same gross output. Thus, the new characteristics of the unit are:

NPHR = 8,000 / ((88/100)*(372/400)) = 9,775 Btu/kWh

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

In Black & Veatch's opinion, gross measurement invalidates the following technologies:

- Air heater and duct leakage control.[1]
- VFD motors.
- Many improved O&M practices.
- Boiler feed pump upgrades.

The case where the gross heat rate would be the better heat rate metric for a coal-fired EGU would be where emissions controls for pollutants such as NO_X, SO_2, etc. must be installed, or upgraded on a unit to meet more stringent emission limits. Taking again our hypothetical unit, if the unit must install an SCR system which requires 5 MW of additional station service, then the gross heat rate would be un-impacted – but the net heat rate would worsen from its baseline value of 9,828 Btu/kWh, to the following

NPHR = 8,000 / ((88/100)*(365/400)) = 9,963 Btu/kWh

In other words, a 1.37% worsening of net plant heat rate. This could be problematic in cases where a unit's performance standard was based on net measurement and an emission control addition resulted in an increased net heat rate that was not contemplated or accounted for when the standard was set.

1.2.4 Are some HRI categories mutually exclusive?

Places where HRI candidates may not result in cumulative HRI benefits include:

- The general category of improved O&M practices. For example, a new air heater may not benefit as much from improved air heater O&M investment due to having a low-maintenance design.
- Economizer upgrades could sometimes shift heat transfer in a boiler such that it could interfere with hot reheat and main steam production, most likely in the case of split backpass units. Economizer upgrades have the risk of reducing

[1] One must be careful to distinguish between air heater heat transfer surface upgrades, which will increase the boiler efficiency, and air heater leakage reduction, which will reduce the station service. In the first case, increasing the boiler efficiency improves both the net and gross plant heat rate. In the second case, reducing the station service only improves the net plant heat rate. The proposed rule is also not clear on whether leakage reduction projects are considered to be mostly in the region of the air heater, or whether these encompass the complete flue gas and air ductwork systems, including boiler inleakage.

boiler exit gas temperatures, which could negatively impact not only SCR performance downstream, but could also negatively impact coal mill performance should mill hot air temperatures be reduced to the point where operations problems occur.

1.2.5 How does capacity factor impact the HRI technologies?

Unit capacity factor can significantly impact the effectiveness of these HRI technologies on the menu list, especially those which can vary in efficiency over load-demand curves and ranges. Also, the effectiveness may vary depending upon the existing technology applied at the unit. For example, based on 2017 EPA and EIA heat rate data (gross basis), subcritical boilers had on average 7% higher heat rate than supercritical boilers. And when heat rate was compared with the annual capacity factor, a decrease in heat rate of 8% was found in units with an 80-90% capacity factor, as compared to units with less than 10% capacity factor. Some of this change in heat rate is due to changes in boiler and turbine efficiency as a function of load, but some of it is due to increased numbers of starts and stops, which require significant heat input without resulting generation during the warm-up period.

Black & Veatch examined net capacity factor and net plant heat rate of coal-fired EGUs in three gross generation categories across the last 10 years for the purpose of demonstrating the potential influence of changes in capacity factor to changes in heat rate. Note that for these comparison graphs, we eliminated units which switched fuel type (such as bituminous to sub-bituminous), and only considered units which operated continuously throughout the period (in other words, omitting units which retired during that time). This led to a population of 90 units less than 200 MWe gross, 155 units from 200-500 MWe gross, and 207 units greater than or equal to 500 MWe gross. See Figures 1-1 and 1-2, respectively.

Figure 1-1 Net Capacity Factor of US Coal-Fired EGUs (10-Years Looking Back)

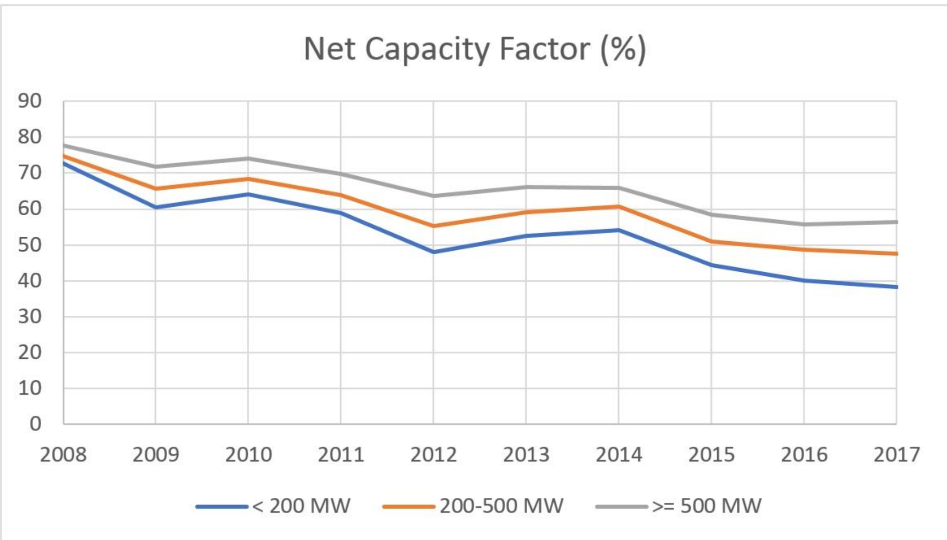
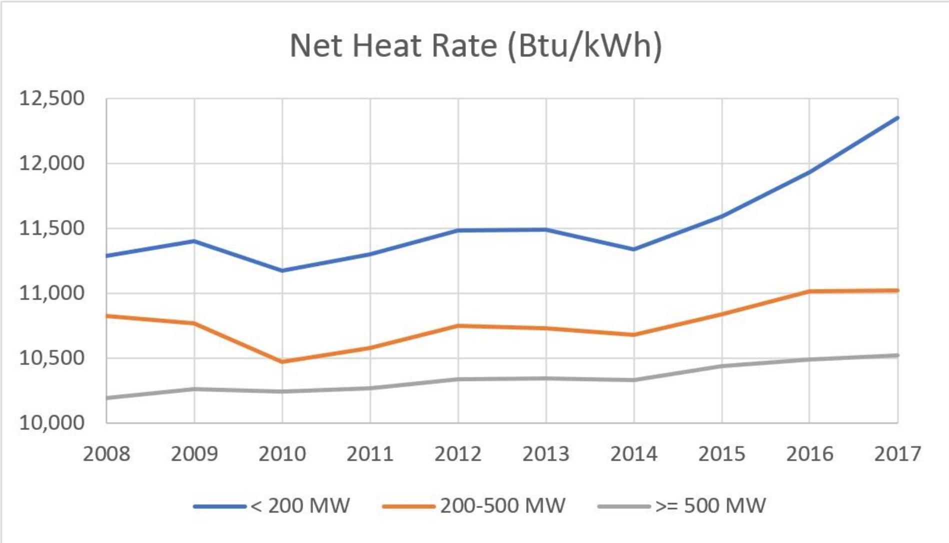


Figure 1-2 NPHR of US Coal-Fired EGUs (10-Years Looking Back)



Figures 1-1 and 1-2 show trends in increasing (worsening) net plant heat rate as a function of the reduction in net capacity factor. While other factors may influence a coal-fired EGU heat rate, such as reduced load and increased starts and stops, lower net capacity factors generally yield poorer net plant heat rates. Although not detailed here, the same general trend in increasing (worsening) gross plant heat rate as a function of reduction in plant capacity factor is also evident.

1.2.6 Are the ranges of HRI for candidates included in Table 1 of the Proposed Rule (44757) reasonable?

While Black & Veatch again wants to emphasize the HRI for candidate application requires individual unit analysis, the following additional observations are relevant to this question:

- The HRI for neural networks and intelligent sootblowing appears to be very optimistic, and may reflect installation on a unit with poor combustion control. Much of the benefit is often simply due to reducing the excess air (measured as excess O_2) level in the boiler. For example, recent studies conducted by Black & Veatch on a 400 MW boiler found that reducing excess O_2 by 0.25% resulted in an HRI of 0.07%, while a reduction in excess O_2 of 0.75% resulted in an HRI of 0.36%. Black & Veatch would expect the total HRI from neural network and intelligent sootblowing deployment to be from 0.20-0.40%.
- The HRI assessed for leakage reduction seems reasonable, especially if air heater baskets are upgraded to reduce the air heater gas exit temperature. However, if the leakage is excessively problematic for a specific generating unit, additional HRI may be possible beyond the improvement shown. Black & Veatch has studied units with air heaters in very poor condition, for which an HRI of 1% has been achievable through a combination of leakage reduction and improved heat transfer.

- The option of redesign or replacement of the economizer is going to be site-specific, as boiler layout and construction varies widely between units. In a study of a 450 MW subcritical unit, Black & Veatch found that adding 10% surface area to the existing economizer tubes resulted in an HRI of 0.15%, and adding 20% surface area resulted in an HRI of 0.28%. The values provided in Table 1 appear to reflect a major economizer redesign, possibly with significant finned tube area, which may not be applicable for many high-ash or high-fouling coals. Moreover, Black & Veatch has found that making significant changes to the economizer can result in myriad other attendant changes that are required for proper unit operation. For example, the change in heat balance can result in loss of hot reheat temperature, thus requiring a redesign of that steam circuit. In other cases, the decrease in boiler exit gas temperature has been significant enough to impact the performance of a downstream selective catalytic reduction (SCR) system, requiring the installation of an economizer gas bypass system to maintain NO_X removal performance.
- The limitation with VFDs is that the major efficiency increases observed occur at part load. If the device is operating near the design point (base-loaded) most of the time, adding a VFD will have limited benefit on heat rate. The HRI estimated in Table 1 appears to be more comprehensive than a single-component VFD retrofit or assumes the unit operating at reduced load from initial design. In a study conducted of an 800 MW subcritical boiler, VFD upgrades for specific plant main drives resulted in overall HRIs ranging from a high of 0.45-0.55% (induced draft fan VFD deployment) to as little as 0.03-0.05% (primary air fan drives). Circulating water and condensate pump VFD deployment tended to result in HRIs of 0.07-0.13% for each system. Cooling tower fan VFD deployment can result in an HRI of 0.05-0.14% depending upon the application.
- Rebuilding the boiler feed pump will serve to bring the efficiency back up closer to the initial design value. The degree of HRI with this option will depend on the extent of performance degradation. Generally speaking, an efficiency improvement of about 5% is the greatest gain expected when upgrading a boiler feed pump drive, whereas pumps may gain 10% or greater total efficiency as a result of rebuilding or upgrading them. However, in the case where the boiler feed pump is electric, upgrading to a VFD for the pump may result in significantly improved performance at part-load conditions. As a result, a boiler feed pump overhaul would be typically expected to provide an HRI of 0.1-0.3%, while the drive upgrade would be expected to provide an HRI of 0.05-0.14%. Thus, we feel that the values given for the potential HRI for boiler feed pumps in Table 1-1 may be optimistic.
- For turbine blade path upgrades[2] the HRI values presented appear to be reasonable for a single blade path upgrade. Additional HRI may be achievable using multiple upgrades. A recent Black & Veatch study on a 400 MW gross subcritical unit found that an HP/IP

[2] Upgrades differ from a typical turbine overhaul in that the goal of a turbine overhaul is typically to return a turbine to its design performance realm without making significant modifications to the design performance and efficiency of the turbine components.

upgrade would result in a 1.9% HRI, which a complete HP/IP/LP upgrade would result in a 3.3% HRI, which is within the range of the HRI values provided in Table 1.

- Efficiency improvement through operations and maintenance practices is difficult to ascertain on a general level, as it is highly plant-specific. However, in the case of deployment of an improved condenser cleaning system, Black & Veatch has found that some units have been able to improve their heat rate by 0.6% or greater.

1.2.7 How should the existing unit heat rate be considered when applying the candidates for applicability?

Many variables should be considered when analyzing the existing or baseline unit heat rate, or when comparing the candidates for HRI. These include individual unit considerations such as the time since the last major boiler or turbine outage, the capacity factor and load-demand curve, and the number of starts and stops of the unit.

Any performance standard established in connection with an HRI analysis should consider fuel quality impacts upon unit heat rate. It should be noted as well that fuel quality even within a given coal seam can vary enough to measurably alter unit heat rate, especially on a short-term (e.g., hourly) basis.

1.2.8 Are there reasons why natural gas co-firing should not be on the candidate list?

The natural gas market price, pipeline capacity at the unit, the ability to acquire firm supply, and local and state regulations will be the prime determinants of the feasibility of natural gas co-firing. Presently, many unit sites do not have natural gas availability, so its inclusion as part of BSER would be inappropriate.

1.2.9 Should compliance be based on a multi-year average considering a unit's historical heat rate, ongoing HRI practices, and possibly additional HRI based on BSER application?

Due to the nature of heat rate constantly being a moving target, it would appear prudent to employ a multi-year average. There are numerous individual unit factors that must be considered when setting a multi-year performance standard. For example, take the common situation of a unit that several years ago was operating at a capacity factor of 60-70%, but now is operating with a capacity factor of 20-30%. Or a bituminous coal-fired EGU which has switched to a high-moisture PRB coal. In addition to a unit's historic heat rate, future operation, coal quality,and numerous other factors will affect the unit's future performance.

A clear solution to these types of problems does not immediately present itself. It does suggest that these considerations affecting performance standard establishment entail individual unit considerations.

1.2.10 Multi-year averaging should account for plant performance degradation between major outage cycles when major maintenance and cleanings can be done. Are the costs for the various candidate HRI measures listed in Table 2 reasonable estimates?

In Table 2 of the proposed rule, we find the following estimated capital costs for the 7 technologies, equipment upgrades, and operating and maintenance practices called out by the

EPA as being the "most impactful" HRI measures that they propose as their BSER for existing coal-fired EGUs.

Table 1-2 HRI Technologies and Summary of Capital Costs (pg. 44759)

TABLE 2—SUMMARY OF COST ($2016/KW) OF HRI MEASURES

HRI measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	4.7	4.7	2.5	2.5	1.4	1.4
Boiler Feed Pumps	1.4	2.0	1.1	1.3	0.9	1.0
Air Heater & Duct Leakage Control	3.6	4.7	2.5	2.7	2.1	2.4
Variable Frequency Drives	9.1	11.9	7.2	9.4	6.6	7.9
Blade Path Upgrade (Steam Turbine)	11.2	66.9	8.9	44.6	6.2	31.0
Redesign/Replace Economizer	13.1	18.7	10.5	12.7	10.0	11.2
Improved O&M Practices	Minimal capital cost.					

The cost estimates are reasonable with the following comments and qualifications:

- Operations and maintenance should also be factored into the analysis of costs.
- In Section 1.2.11 regarding costs of the technologies, the table details capital costs. In addition to capital costs, there could be extensive replacement power costs associated with taking an extended outage to implement these technologies (particularly for the turbine blade modifications and for the economizer tube replacements).
- Repairing air heater and ductwork leakage can be more difficult to assess. Ductwork leakage repair can be a straightforward repair or more complicated. If the ductwork leakage source is a few large leaks (such as failing expansion joints), these items can be easily determined and replaced. If there are numerous small leaks throughout the ductwork, repairs can become very labor-intensive with little benefit. Based on Black & Veatch's experience, the prices shown appear to be in line with quotes received for similar work for air heater replacement seals, but might not be representative of major repairs for more extensive duct leakage.
- Although VFDs can increase the fan efficiency (especially at the part load condition), implementation of the VFD can be costly. Each VFD will require space for the addition of the variable frequency controller. For many applications, this can mean the addition of a small building for each VFD and heat exchanger. The costs presented do not appear to include VFDs for multiple components, only a single component (only ID fans or boiler feedwater pumps, etc.). However, for a single component, the costs appear reasonable.
- The proposed ACE rule was not specific about the extent of the turbine blade path upgrades. A single steam turbine stage could be upgraded or multiple stages. As a result, the costs presented in Table 1-2 appear to be on the low side and representative only of a single blade path upgrade.
- For any option that includes a partial or full unit outage that cannot be accommodated within a regularly scheduled plant outage, the potential cost of lost generation and lost availability in the market should also be considered. While outage durations will vary depending upon each unit and installation, general rules of thumb may be used to

estimate their magnitude. For example, installation of a VFD for an induced draft fan may require 6-8 weeks of pre-outage work, followed by 1 week of outage per fan to establish the final tie-in. Obviously, this could be done within a seasonal outage with little difficulty. On the other end of the scale, an economizer redesign may require a minimum 8-week boiler outage, and in some cases, depending upon the accessibility of the boiler within its building, 12 or more weeks. For a 500 MW net unit operating at a load-demand of 50% net capacity factor and assuming a market price of $25/MWh and production cost of $15/MWh, the lost generation from even a 1-week outage equates to a loss of $420,000.

1.2.11 Are there candidates on the list that require ongoing attention as opposed to a single implementation?

Most of these candidate HRIs will require regular attention in order to maintain their performance. In some cases, these will be mostly O&M-focused, and in others mostly capital-focused.

Table 1-3 HRI O&M and Capital Requirements for Sustained Performance

HRI CANDIDATE	O&M FREQUENCY	CAPITAL IMPROVEMENT FREQUENCY
Neural Network/Intelligent Sootblowers	Increased O&M from normal. Could be continuous if third-party monitoring and diagnostics are used.	Primarily at project start.
Boiler Feed Pumps	Equivalent to existing for BFPs.	Significant at project start.
Air Heater & Duct Leakage Control	Potentially increased O&M needed to maintain systems.	Primarily at project start.
Variable Frequency Drives	Regular O&M needed to maintain systems.	Primarily at project start.
Blade Path Upgrade (Steam Turbine)	Regular O&M needed to maintain systems.	Significant at project start.
Redesign/Replace Economizer	Regular O&M needed to maintain systems.	Significant at project start.
Improved O&M Practices:		
Adopting HRI Training for Plant O&M Staff	Increased O&M from normal.	N/A
Adopting On-Site Appraisals for Identifying Additional HRI Areas	Increased O&M from normal.	N/A unless specific needs are uncovered.
Improved Condenser Cleaning Strategies	Increased O&M from normal.	Potentially at project start.

1.3 TIMING OF COMPLIANCE OBLIGATIONS

1.3.1 What additional guidance should EPA include to allow a state to elect a longer compliance timeline? Is it reasonable that implementation of HRI projects be allowed under the existing outage schedule in effect for a given unit, recognizing that some HRI projects can be implemented during short routine scheduled maintenance outages, while other HRI projects may require a longer major outage to implement?

In most cases it would be reasonable to give coal-fired EGUs the option of incorporating the HRI projects into their regular planned maintenance outages, recognizing that some HRIs require longer outage periods in order to complete the HRI installation. For example the typical outage time between turbine overhauls can be as short as 6 years, with many units able to achieve a 10-year outage schedule. Major boiler outage scheduling is typically 3-5 years. If these outage schedules are to be maintained, a unit's compliance schedule would need to reflect time to implement associated HRI measures. HRI projects should be allowed to occur at the closest outage of sufficient duration to avoid taking premature and expensive additional outage time just to install these technologies. For example, it would only make sense to perform a steam path upgrade, if applicable to a unit, during a regularly schedule turbine overhaul.

In the case of some HRIs preparation, planning, and some implementation can be performed earlier. One example could be implementing installation of neural networks and/or intelligent sootblowing, whereby some early work could be done regarding installation of new instrumentation and development of site-specific software.

Table 1-4 shows the estimated outage times required for different HRI candidates, based upon Black & Veatch experience.

Table 1-4 Typical HRI Logistics

HRI CANDIDATE	< 10 DAY OUTAGE	10 TO 30-DAY OUTAGE	> 30 DAY OUTAGE
Neural Network/Intelligent Sootblowers	Yes	Rarely	No
Boiler Feed Pumps	Possible	Yes	Rarely
Air Heater & Duct Leakage Control	Possible	Yes	Rarely
Variable Frequency Drives	Yes	Possible	Rarely
Blade Path Upgrade (Steam Turbine)	No	Possible	Yes
Redesign/Replace Economizer	No	Rarely	Yes
Improved O&M Practices:			
Adopting HRI Training for Plant O&M Staff	No	No	No
Adopting On-Site Appraisals for Identifying Additional HRI Areas	No	No	No
Improved Condenser Cleaning Strategies	Yes	Rarely	No

2.0 Summary

The following conclusions can be drawn from this analysis by the NRECA and Black & Veatch of the of the EPA's Proposed ACE Rule:

- In general, for the industry fleet of affected EGUs, the list of proposed ACE rule HRI "candidate technologies" is a reasonable list, and there is no need to expand the list.
- The justification to implement and the potential impact of each HRI candidate technology is very specific to each EGU, which should be taken into consideration by the States.
- Standards of performance based on gross generation are more reasonable and accurate to measure than net generation, which could be problematic. If gross is finalized in the ACE rule, the list of HRI candidate technologies should be reviewed for applicability to auxiliary load and thermal efficiency improvement, and adjusted if appropriate.
- Multi-year averaging would help to address the high variability of heat rate in the fleet of affected EGUs.
- Compliance schedules should take into account reasonable lead times for planning and implementing HRI projects.