National Energy Technology Laboratory
U.S. Department of Energy
OFFICE OF FOSSIL ENERGY

Options for Improving the Efficiency of Existing Coal-Fired Power Plants

April 1, 2014

DOE/NETL-2013/1611

Disclaimer

Options for Improving the Efficiency of Existing Coal-Fired Power Plants

DOE/NETL-2013/1611

Final Report

April 1, 2014

NETL Contact:

Eric Grol
General Engineer
Strategic Energy Analysis and Planning Division

National Energy Technology Laboratory
www.netl.doe.gov

Prepared by:

National Energy Technology Laboratory (NETL)

Eric Grol
Strategic Energy Analysis and Planning Division

Thomas J. Tarka, P.E.
Strategic Energy Analysis and Planning Division

Energy Sector Planning and Analysis (ESPA)

Steve Herron
WorleyParsons Group, Inc.

Paul Myles
WorleyParsons Group, Inc.

Joseph Saracen
WorleyParsons Group, Inc.

DOE Contract Number DE-FE0004001

Acknowledgments

This report was prepared by Energy Sector Planning and Analysis (ESPA) for the United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). This work was completed under DOE NETL Contract Number DE-FE0004001. This work was performed under ESPA Task 150.09.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Eric Grol, NETL Technical Monitor

This page intentionally left blank.

Table of Contents

Exhibits

Acronyms and Abbreviations

ADSP	Advanced Design Steam Path
AR	As-received
ASU	Air separation unit
B&W	Babcock & Wilcox
BAH	Booz Allen Hamilton
Btu/hr	British thermal units per hour
Btu/kWh	British thermal units per kilowatt hour
Btu/lb	British thermal units per pound
cf	Cubic feet
CFD	computational fluid dynamic
CFPP	Coal-fired power plants
cm	Centimeter
CO_2	Carbon dioxide
COE	Cost of electricity
COS	Combustion optimization system
DNI	Direct normal irradiance
DOE	Department of Energy
DP&L	Dayton Power and Light
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESPA	Energy Sector Planning and Analysis
FGD	Flue gas desulfurization
ft	Foot, Feet
gal	Gallon
GE	General Electric
h, hr	Hour
Hg	Mercury
HHV	Higher heating value
HP	High pressure
ID	Inside diameter
IP	Intermediate pressure
kg/GJ	Kilograms per gigajoule
kg/hr	Kilograms per hour
kgmol	Kilogram mole
kgmol/hr	Kilogram moles per hour
kJ	Kilojoule
kJ/hr	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
lb/hr	Pounds per hour
lb/ft^2	Pounds per square foot
lb/MMBtu	Pounds per million British thermal units
lbmol	Pound mole
lbmol/hr	Pound moles per hour
lb/MWh	Pounds per megawatt hour
LCOE	Levelized cost of electricity
LOI	Loss on ignition
LP	Low pressure
m	Meter
m/min	Meters per minute
m^3/min	Cubic meters per minute
md	Millidarcy (a measure of permeability)
MCR	Maximum continuous rate
MMBtu/hr	Million British thermal units per hour
MW,MWe	Megawatt electric
N/A	Not applicable
NEI	Nuclear Energy Institute
NETL	National Energy Technology Laboratory
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
O&M	Operation and maintenance
OEM	Original Equipment Manufacturer
PC	Pulverized coal
PM	Particulate matter
PRB	Powder River Basin
PRV	Pressure-reducing valve
ROI	Return on investment
SAFWH	Solar assisted feed water heater
scf	Standard cubic feet
scfd	Standard cubic feet per day
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
Sch.	Schedule
scmh	Standard cubic meter per hour
SCR	Selective catalytic reduction
SEAP	Office of Strategic Energy Analysis & Planning
SO_2	Sulfur dioxide
SS	Stainless steel
STI	Storm Technologies, Inc.
TOC	Total overnight cost
tonne	Metric ton (1,000 kg)
TPC	Total plant cost
TS&M	Transport, storage, and monitoring

U.S.	United States
\$/MMBtu	Dollars per million British thermal units
\$/MMkJ	Dollars per million kilojoules
\$M	Millions of dollars
\$/bbl	Dollars per barrel
μS/cm	micro Siemens per cm
°C	Degrees Celsius
°F	Degrees Fahrenheit

Executive Summary

The existing coal-fired power generation fleet consists of over fifteen hundred separate units ranging in size from just a few megawatts (MW) to thirteen hundred (1,300) MW. Together these coal-fired power plants (CFPPs) constitute over 300 gigawatts (GW) of installed electric generating capacity and are responsible for generating more electricity than any other fuel type in the United Sates: between thirty-seven and fifty percent of the total kilowatt-hours (kWh) produced annually during the last decade. This trend is expected to continue, with total generation from coal projected to increase slightly over the next two decades.

Previous work by NETL's Office of Systems, Analyses, and Planning examined the potential for reducing domestic greenhouse gas (GHG) emissions through efficiency improvements to the existing fleet. (1), (2), (3) That work identified retrofits or operational improvements as having the potential for significant emissions reductions, up to 2.5 percent of domestic CO_2 emissions, but suggested additional study was needed.

This study builds upon that work, examining the economic case for implementing common retrofits on two hypothetical power plants which are representative of CFPPs in the existing fleet. In each retrofit case, the potential performance improvement (and subsequent reduction in emissions) is evaluated, followed by a simplified economic analysis to determine the business case for making such a decision. A "comprehensive retrofit" case is then evaluated where several of the technologies are combined.

An additional analysis was also performed on a selected "up and coming" technology. This analysis highlights that additional research pathways exist which can further reduce emissions and improve the performance of CFPPs.

As is detailed below, the report found that the performance of existing CFPPs could be improved significantly with "off the shelf" technologies, especially in the case of older plants which would benefit to a greater extent than more modern ones. That these older plants could achieve efficiencies as high as in the range of 34 to 35 percent would seem to validate NETL's earlier work, and identifies a significant opportunity to reduce domestic GHG emissions while providing reliable and affordable electricity to the nation.

Study Results

This study examines four separate efficiency improvements evaluated for coal-fired power plants. These improvements are achieved by making modifications to four plant components: the coal pulverizer, condenser, steam turbine, and adding solar-assisted feed water heaters.

The efficiency gains are applied to two generic, pulverized coal power plants referred to as Plant A and Plant B. These plants are described in Exhibit ES-1. Two different plants were used in this study to reflect the diversity among the existing coal power generation fleet. Plant A is representative of an average 400 to 600 megawatt (MW) size power plant in the existing fleet. Plant B is representative or newer plants in the same size range. Both plants have subcritical steam cycles.

Exhibit ES-1 Existing Coal Unit Vintage

Plant	Year Built	Net Output, MW_e	Heat Rate, Btu/kWh	Efficiency, HHV
Plant A	1968	550	10,559	32.3%
Plant B	1995	550	9,680	35.2%

The four efficiency improvement projects evaluated in this study are:

1. **Coal Pulverizer Improvement**: Upgrading the coal pulverizer and related technologies will increase particle fineness, improving combustion and thereby increasing efficiency. This option had a relatively long payback period but may still be an attractive option for select plants. Included in this option are the latest generation of off-the-shelf pulverizers, an advanced classifier, and a combustion optimization system.
2. **Condenser Improvement**: Improving (i.e. reducing) the condenser leakage rate is an attractive upgrade option due to its potential high efficiency gains, available technology, and relatively short payback period. This includes tube replacement, reducing leaks, condenser reconfiguring, and various other upgrades descried in the study.
3. **Steam Turbine Upgrade**: Steam turbine efficiency is the most attractive of the four to implement as it is the primary power conversion component in a coal-fired power plant. This includes mainly the dense pack turbine retrofit which provides multiple upgrades, as described in Section 5.1.4.
4. **Solar Assisted Feedwater Heaters**: Solar assisted feedwater heater technology uses solar energy to heat boiler feedwater, rather than steam extracted from the steam turbine. This is slightly different than the previous three efficiency improvements, as it is not an improvement to an existing piece of equipment, but the addition of solar power to the cycle, which increases general plant efficiency.

While the first three efficiency improvements are considered to be "off the shelf" technologies, solar assisted feedwater heaters are considered to be less mature, and may require further research, development, and demonstration before industry is willing to adopt the technology. For the sake of clarity, two sets of possible efficiency improvement results are presented: one that combines the three "off the shelf" technologies, and a second, separate case which presents the potential of solar assisted feedwater heaters. This is done to underscore that the latter technology will require further research and development before it can be deployed at scale.

"Off the Shelf" Technologies

The potential CO_2 emission reductions achieveable when all three "off the shelf" technology improvements are applied to the existing coal units examined in this study, are shown in Exhibit ES-2. A "lower" and "upper" bound scenario is also presented for each plant in order to describe the likely range of improvements achievable. The range of improvements is predicated on the assumption that the retrofits will not be additive, but instead that certain improvements may be offsetting. The methodology utilized to estimate the level of improvements, along with a more optimistic case, are detailed below in Sections 7 and 8. The combined retrofit cost is just over $36 million dollars, or $66/kW, for each plant.

As shown, the potential exists to reduce (i.e. improve) the heat rate of Plant A by between 547 and 731 Btu/kWh, resulting in a 5.1 to 6.9 percent reduction in CO_2 emissions, respectively. The upper bound heat rate of 9,828 Btu/kWh for Plant A equates to a 34.7 percent efficiency on a higher heating value (HHV) basis, a 2.4 percentage point increase over it's initial performance.

The results for Plant B are less substantial, but still significant: a 1.7 to 3.3 percent reduction in CO_2 emissions are achievable, and at the upper bound heat rate of 9,340 Btu/kWh, the plant is operating at a 36.5 percent efficiency, a 1.3 percentage point increase.

Exhibit ES-2 Cumulative CO_2 Emission Reduction Summary[i]

Plant	Heat Rate, Btu/kWh[ii]	Pre-retrofit CO_2 Emissions, Million tonne/yr[iii]	Post-retrofit CO_2 Emissions, Million tonne/yr[iiii]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A – Lower Bound	10,012 (547 reduction)	3.93	3.73	0.20 (5.1%)
Plant A – Upper Bound	9,828 (731 reduction)	3.93	3.66	0.27 (6.9%)
Plant B – Lower Bound	9,510 (170 reduction)	3.60	3.54	0.06 (1.7%)
Plant B – Upper Bound	9,340 (340 reduction)	3.60	3.48	0.12 (3.3%)
New Subcritical PC (4)	9,277 (n/a)	3.45	-	-

[i] Includes pulverizer and condenser improvement and steam turbine upgrade, but not solar assisted feedwater heaters.

[ii] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "547 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 547 Btu/kWh and the power plant is more effiecient.

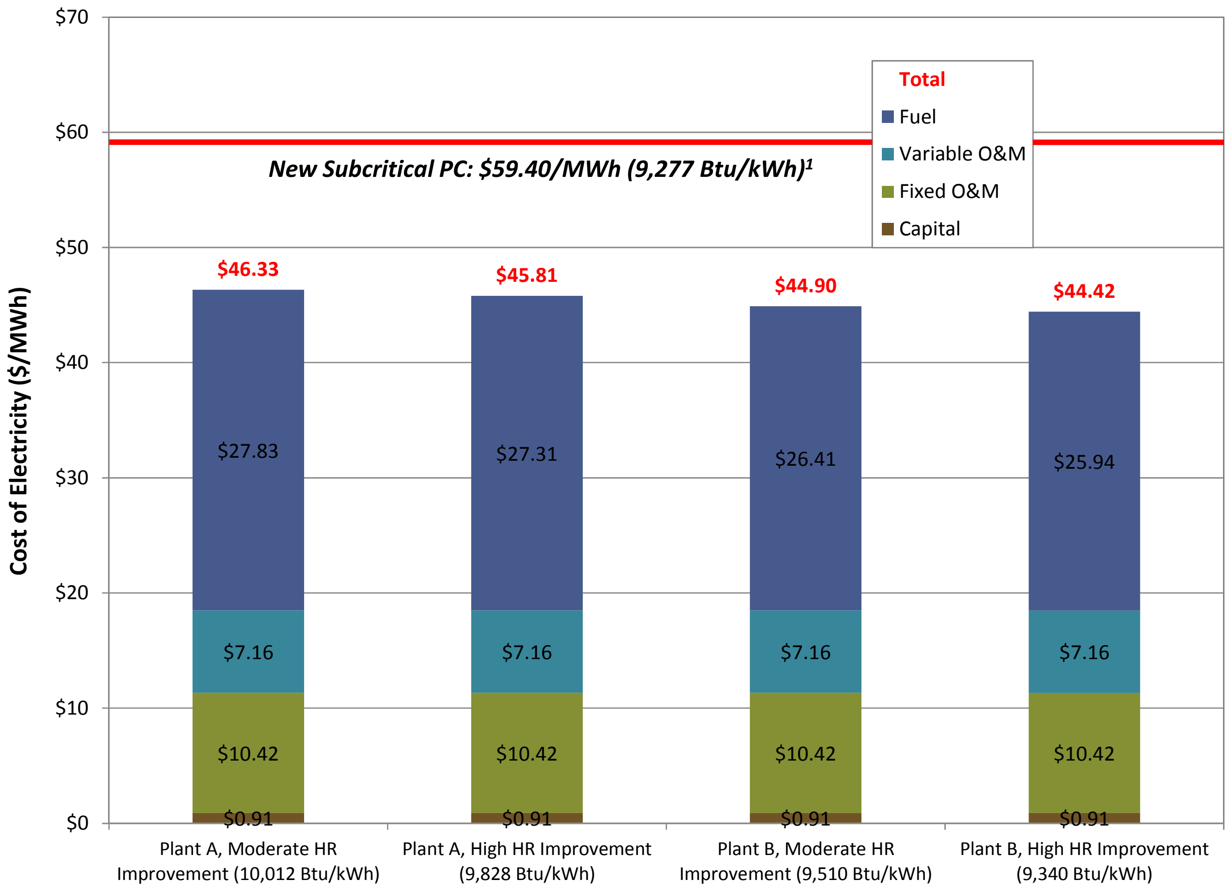
[iii] Assumes annual capacity factor of 85%

As these results show, the potential reduction in emissions (in percent terms) is greatest when the base plant (before retrofit) is less efficient. This is a recurring theme throughout the analysis, and is intuitive: **when efficiency improvements are performed at an existing coal unit, there is greater potential for improvement at a unit that operates less efficiently to begin with, than at a newer unit with an already-low heat rate**. For newer coal units, such as Plant B considered in this study, the three "off the shelf" technology improvements could reduce CO_2 emissions nearly to the level of a new subcritical pulverized coal (PC) unit that does not employ carbon capture and storage. This finding – that an almost 20 year old plant can perform almost to the level of a new, albeit subcritical plant – is significant given questions regarding whether new coal-fired capacity will be built in upcoming years, due to regulatory and market undercertainties.

Exhibit ES-3 shows the first-year cost of electricity (COE) that results from employing all three "off the shelf" technology improvements at both older units (such as Plant A), as well as newer ones (such as Plant B). The cost of electricity for all cases is 22 – 25% below the cost of a new, subcritical pulverized coal unit. It is noteworthy that the potential heat rate improvement at newer coal units (such as Plant B) could result in CO_2 emissions that are approximately 1% greater than new subcritical coal units (without employing carbon capture), but cost approximately 25% less (on a cost of electricity basis). This could be a strong incentive for performing efficiency upgrades at coal units, as a strategy for reducing CO_2 emissions from the existing power generation fleet.

While the first-year COE in each of these cases is significantly lower than that of a new subcritical plant, the changes in COE from the pre-retrofitted plants are less dramatic. For Plant A, the COE reduction ranges from just over a half a percent to a 3.5 percent reduction for the most optimistic scenario of implementing all three technologies. In the case of Plant B, the pulverizer upgrade actually resulted in a slight (less than one percent) increase in COE, while upgrading the steam turbine results in a reduction of 1.4 percent. These results illustrate that a "one-size fits all" solution does not exist when it comes to power plant retrofits, and that some retrofits may not make sense for certain plants, such as pulverizer upgrade for Plant B. Instead, utilities are likely to weigh their options based on the expected plant life, anticipated fuel costs, and other such factors – such as familiarity with a technology – before making the decision to invest in capital improvements.

Exhibit ES-3 Cumulative Efficiency Improvement First-Year Cost of Electricity[iv]



Solar Assisted Feedwater Heater

The solar assisted feedwater heater retrofit case (which does not include any of the other 3 efficiency improvements described above) also holds promise. Exhibit ES-4 shows potential for reductions in CO_2 emissions that are roughly equivalent to the combined "off the shelf" scenario presented above, for both Plant A and Plant B.

The improved heat rate of 9,820 Btu/kWh for Plant A equates to a 34.7 percent efficiency on a higher heating value (HHV) basis, a 2.4 percentage point increase over it's initial performance. This could result in a potential reduction in emissions of 7.1 percent over the pre-retrofitted plant.

The results for Plant B are less substantial, but still significant: a 1.7 to 3.3 percent reduction in CO_2 emissions are achievable, and at the upper bound heat rate of 9,332 Btu/kWh, the plant is

[iv] Includes pulverizer and condenser improvement and steam turbine upgrade, but not solar assisted feedwater heaters.

operating at a 36.6% efficiency, a 1.4 percentage point increase. Notably, the annual CO_2 emissions for newer coal units (such as Plant B) that install solar feedwater heaters is potentially less than 1% greater than the emissions from a new subcritical coal unit (that does not employ carbon capture and storage).

Likewise Exhibit ES-5 shows that the cost of electricity impact for the addition of solar feedwater heaters is roughly the same as for the three previous efficiency upgrades combined. While the addition of solar feedwater heaters is a potentially attractive upgrade, it is emphasized that this technology is likely to require further research, development, and demonstration before widespread adoption is possible.

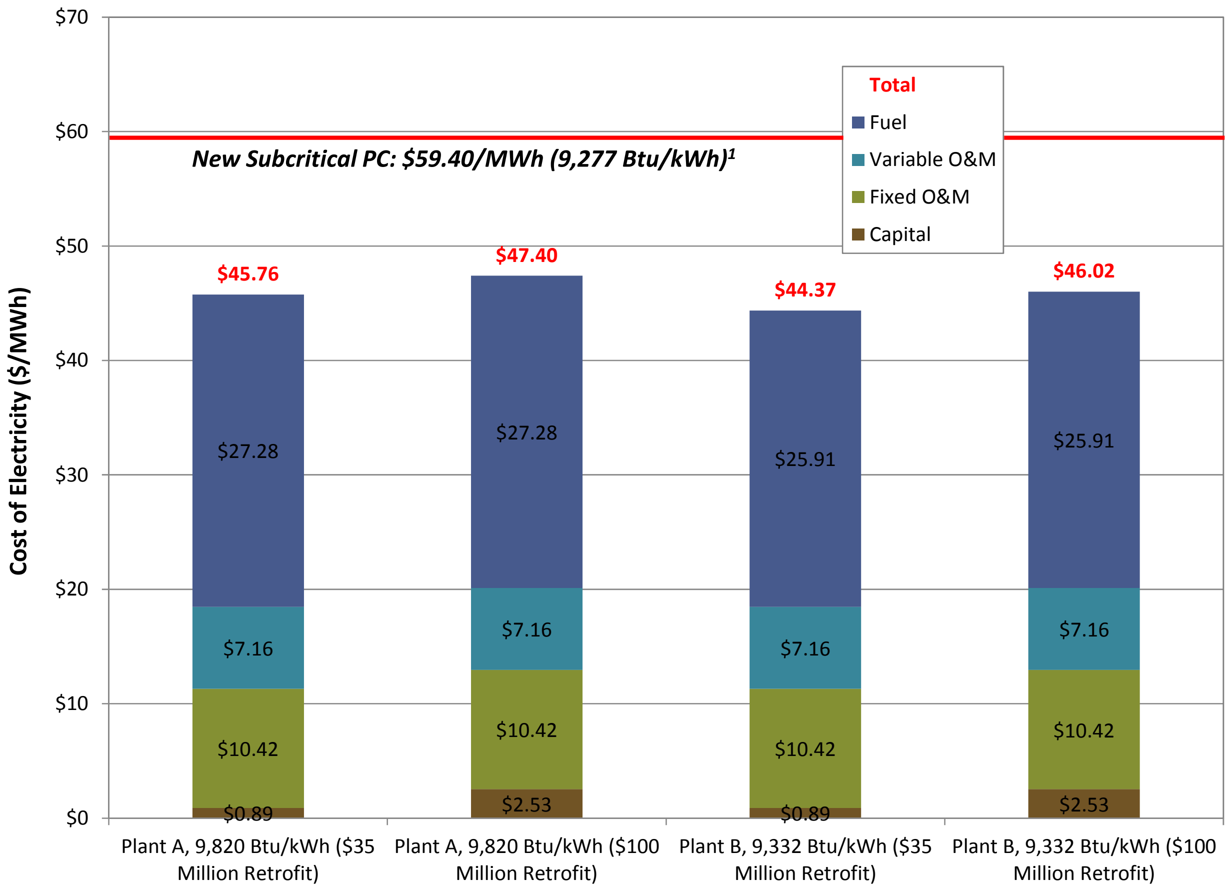
Exhibit ES-4 Solar Assisted Feedwater Heater CO_2 Emission Reduction Summary

Plant	Heat Rate, Btu/kWh[v]	Pre-retrofit CO_2 Emissions, Million tonne/yr[vi]	Post-retrofit CO_2 Emissions, Million tonne/yr[vi]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A	9,820 (739 reduction)	3.93	3.65	0.28 (7.1%)
Plant B	9,332 (348 reduction)	3.60	3.47	0.13 (3.6%)
New Subcritical PC	9,277 (n/a)	3.45	-	-

[v] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "739 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 739 Btu/kWh and the power plant is more effiecient.

[vi] Assumes annual capacity factor of 85%

Exhibit ES-5 Solar Assisted Feedwater Heater First-Year Cost Of Electricity



1 Introduction

The existing coal-fired power generation fleet consists of over fifteen hundred separate units ranging in size from just a few megawatts (MW) to thirteen hundred (1,300) MW. Together these coal-fired power plants (CFPPs) constitute over 300 gigawatts (GW) of installed electric generating capacity and are responsible for generating more electricity than any other fuel type in the United Sates: between thirty-seven and fifty percent of the total kilowatt-hours (kWh) produced annually during the last decade. This trend is expected to continue, with total generation from coal projected to increase slightly over the next two decades.

Previous work by NETL's Office of Systems, Analyses, and Planning examined the potential for reducing domestic greenhouse gas (GHG) emissions through efficiency improvements to the existing fleet. (1), (2), (3) That work identified retrofits or operational improvements as having the potential for significant emissions reductions, up to 2.5 percent of domestic CO_2 emissions, but suggested additional study was needed.

This study builds upon that work, examining the economic case for implementing common retrofits on two hypothetical power plants which are representative of CFPPs in the existing fleet. These include the following efficiency improvement areas: coal pulverizer, condenser, and steam turbine. In each upgrade area, the potential performance improvement (and subsequent reduction in emissions) is evaluated, followed by a simplified economic analysis to determine the business case for making such a decision. A "comprehensive retrofit" case is then evaluated where several of the technologies are combined.

An additional analysis was also performed on a selected "up and coming" technology: solar assisted feedwater heaters (SAFWH). This analysis highlights that additional research pathways exist which can further reduce emissions and improve the performance of CFPPs.

The goal of this report is to highlight aspects of the decisions faced by utilities in evaluating their CFPP portfolio, and to examine how certain CFPPs may be more of less amenable to common retrofit options. Understanding the opportunities and these choices is critical in understanding how we can achieve meaningful reductions in GHG emissions from the existing fleet, given the projection that these plants will continue to provide electricity for the next several decades.

1.1 Scope

Four retrofit opportunities were examined individually, then a second analysis was performed in order to assess the cumulative impact of retrofitting multiple areas of the plant at once. This latter analsysis was limited to the three technologies which are currently available "off the shelf" in order to evaluate the near term opportunites for utilities and to inform policy makers.

The fourth technology – solar feedwater heaters – is considered to be an area of further interest for research by will require additional demonstration before it is ready for wide-scale deployment.

The following metrics were reported for each scenario: (1) efficiency benefits, (2) CO_2 emissions reductions over the un-retrofitted plant, and (3) payback time. The latter was reported based on a simplified calculation that compared the annual fuel cost savings to the capital cost of the plant.

While it is understood the latter metric is highly sensitive to how often the plant dispatches (i.e. it's capacity factor), it is assumed that upgrades are being performed so that these plants can serve as baseload generation.

The study did not attempt to perform in-depth or Aspen modeling of the hypothetical power plants, but instead relied on the results of actual upgrades to "real world" plants reported in the literature.

Similarly, it was recognized that a multitude of "off the shelf" technologies are available to improve the efficiency of existing coal-fired power plants, but the scope of this analysis was limited to three areas deemed to be common areas of improvement. Future work will expand on this survey of technologies, but the hetrogenity of existing coal-fired generation units may make it difficult to report meaningful findings without dramatically increasing the scope of work.

Lastly, only a simple economic analysis was performed. In reality, utilities make retrofit and capital expenditure decisions based on a host of variables. These include, but are not limited to: anticipated market and regulatory conditions, their current asset portfolio, current corporate performance and strategic vision, technologies with which they are familiar, and general corporate culture. The economic analysis was therefore provided as a data point but should not be viewed as the last word in whether a utilitiy will invest in retrofitting a power plant.

2 Case Study

The diversity of the existing coal-fired power generation fleet means that the impact of any given efficiency improvement or upgrade will vary based on the plant to which it is applied. In order to explore how important these impacts might be, each efficiency improvement evaluated in this study was applied to two different hypothetical power plants. Each plant has different underlying equipment – such as the type of pulverizer – based on what equipment was common during the era that plant was built. These plants therefore provided two "case studies", in which alternative equipment was upgraded or enhanced for efficiency gain.

The cost and impact of each efficiency improvement was ascertained by performing a literature search of existing cases studies, where "real-world" data was collected on upgrading actual plants. This data was used as a basis for how particular improvements would impact the hypothetical power plants chosen for our case studies.

Both Plant A and Plant B are similar in that they are subcritical, pulverized coal (PC) power plants fired on bituminous coal. They each have a net output of 550 MW, a size chosen to reflect the size of the coal-fired power plants in the National Energy Technology Laboratory (NETL) study, "*Cost and Performance Baseline for Fossil Energy Plants; Volume 1: Bituminous Coal and Natural Gas to Electricity*". (4) The remaining salient details on each plant is described below.

2.1 Basis for Plant A

"Plant A" is a 550 MW coal-fired power plant built in 1968. The age was based on the average age of a 400 to 600 MW coal-fired power plant in the United States.[vii] Plant A has a net heat rate of 10,559 Btu/kWh. The plant includes a ball mill style coal pulverizer. The condenser is assumed to be copper/Admiralty tubes with a condenser pressure of 2.75" Hg. The turbine is a General Electric (GE) free vortex design with a high pressure (HP) steam path efficiency of 88 percent and an intermediate pressure (IP) efficiency of 89 percent.

2.2 Basis for Plant B

"Plant B" is a 550 MW coal-fired power plant built in 1995. The age was chosen to be representative of younger plants in the coal-fired power fleet. It is representative of real-world coal-fired power plants built in that era. Plant B has a net heat rate of 9,680 BTU/kWh. The plant includes a first generation Babcock & Wilcox (B&W) MPS 89 style coal pulverizer. The condenser is assumed to be stainless steel tubes with a pressure of 2.25" Hg. The turbine is a GE second generation advanced vortex design with integral covered buckets and an HP steam path efficiency of 91 percent and an IP efficiency of 94 percent.

3 Analysis 1: Coal Pulverizer

Coal pulverizer improvement is the first in a series of efficiency improvements that was evaluated in this study. This class of improvement was initially selected due to its high efficiency gains, technology availability, ease of implementation, and presumed shorter payback period.

Coal pulverizers reduce the size of the coal particles to a fineness acceptable to the pulverized coal (PC) boiler. The coal, once ground into a fine powder, is mixed with air and distributed to the burners for ignition. Controlling both the fineness and the air-mixture can have a dramatic impact on plant performance, as is described below.

3.1 Pulverizer Types

Market and regulatory conditions have caused many coal plants in the U.S. fleet to switch coal types – e.g. from a higher rank bituminous coal to a lower rank subbituminous coal – during their life span. However, coal switching can change the energy content (Btu/lb) of the coal, requiring the operator to decide between the producing less power (derate), or equipment upgrades to accommodate – amongst other things – higher coal feed rates and new coal characteristics. This can require new pulverizers, burners, classifiers, and other pieces of ancillary equipment. While some plants simply derate rather than retrofit, increasing the efficiency of the coal pulverizer process could provide a significant increase in efficiency to avoid derating.

[vii] Source: Based on data derived from Ventyx, Velocity Suite, October 2013.

As a result, a variety of pulverizers are commonly found PC plants. Not only does each type have different performance characteristics, but performance may vary widely within a type as technological advances have been made to reduce how parts wear or to more efficiently provide a more consistent product. These types of pulverizers are commonly used in PC plants:

Ball Tube Mills – The mill consists of tubes with alloy balls. The coal is sent in through a rotating tube as the balls tumble on the coal due to tube rotation.

Impact Mills – The mill consists of a series of fixed hammers inside a cylinder. The coal is sent in through the cylinder where the hammers crush the coal against wear plates.

Bowl Mills (Ring-Roll) – Another type of ball mill, this mill consists of balls along a ring track. The coal is sent in through the bowl where the ball grinds the coal and the rings and/or ball rotate. The majority of the existing coal power plant fleet use this style of ball mill.

Vertical Roller Mills – The mill consists of vertical tire-like rollers that pulverize coal feed to a rotating table. This is the most recent efficient design.

3.2 Technical Advances in Pulverizers

Starting in 1980, combustion system designs changed due to the New Source Performance Standards (NSPS) originially established in the Clean Air Act of 1970. After 1990, the Clean Air Act Title IV was enacted, which required control of particulate matter (PM), SO_2 and NOx, resulting in in further changes to combustion systems. Plants could meet emissions requirements by deploying a number of control technologies, such as selective catalytic reduction (SCR), flue gas desulfurization (FGD) units, and improved bag houses. Another option was the deployment of equipment that made the plant more efficient. Improved coal pulverizer technologies – and associated air distribution and classification equipement – were one of the these upgrade options after they were shown to increase efficiency and decrease emissions. For example, it has been determined that increases in particle fineness has caused a decrease in loss on ignition (LOI) – a metric which describes the amount of uncombusted fuel – in the ash.

Since that time, subsequent advances made in the pulverizers, air distribution, and classifier technology have resulted in an increased maximum efficiency for new coal-fired power plants. Furthermore, pulverizers also play a significant role in the operating efficiency of a plant – how it's actual performance compares to it's design (or nameplate) performance. One study estimates that 75 percent of the controllable or correctable efficiency improvements are related to coal fines and air distribution for fuel combustion. (5)

3.3 Particle Fineness

Prior to combustion, coal is crushed into a fine powder. The fineness of this powder (or "particle fineness") is typically measured by a percentage of the coal that can pass through a given mesh size. The larger the particle size, the higher the level of unburned carbon in the ash. Larger particle sizes also require more time to combust, propagating the flame higher in the boiler, thereby increasing de-superheater spray flowrates, and dry gas losses, which decreases overall boiler efficiency.

Before 1980, pulverized coal burners were very turbulent with high combustion efficiency even with large particle sizes. Therefore, more complete grinding and classification of the coal was deemed unnecessary. However, the need to reduce criteria pollutants such as particulate matter (PM), SO_2 and NOx, led to the advent of staged combustion and low NOx burners: suddenly particle sizes became more important. Exhibit 6 is a table of fineness standards typical of plants prior to the 1980s.

Exhibit 6 Sample of fineness standards for pulverized coal prior to 1980 (6)

Coal Rank	Minimum weight % passing 200 mesh (<75 microns)	Maximum weight % retained on 50 mesh (<300 microns)
Low to medium volatile bituminous	70 – 75	2
High volatile bituminous	65 – 72	2
Sub-bituminous or lignite	60 – 70	2

Current technologies and optimizations can achieve $\geq$75% passing through 200 mesh and <0.1% retained on 50 mesh. (7) New “S-Style” classifiers from SAVvy Engineering can optimize the pulverization even further, achieving virtually 100 percent passing 50 mesh. (6)

3.4 Loss On Ignition

LOI level is the level of unburned carbon particles – or unburnt fuel – found in fly and bottom ash. LOI is caused by three major factors: 1) Insufficient furnace oxygen, 2) poor fuel/air ratio, and 3) large particle sizes.

Exhibit 7 describes where optimum LOI levels should be.

Exhibit 7 LOI levels (7)

Fuel Type	Good	Average	Poor
Eastern Bituminous	<5%	8 - 12%	>10%
Western Lignite / Powder River Basin (PRB)	<0.2%	0.2 - 0.7%	>1%

One example found that a decrease in LOI from 35.88 percent to 20.7 percent increased efficiency of the boiler by 2.52 percent. (7) Typical efficiency gains through reduced LOI can range from between a 25 – 50 Btu/kWh improvement in heat rate.

A high LOI is an obvious indicator of fuel loss, which means lower efficiency and lost revenue. Materials handling systems, including pulverizers, are processing coal, some of which is not burned in the combustion process, reducing efficiency. Fuel savings are significantly increased by decreasing the amount of unburned carbon in the ash. The Environmental Protection Agency (EPA) estimates that a coal plant with 10 percent ash coal, and an LOI of 20 percent has a 2.5

percent fuel loss. This fuel loss does not include any heat rate penalty, which would further reduce efficiency. (8)

3.5 Heat Rate Improvement

Reducing the particle size in a greater percentage of the feedstock lowers LOI levels, thereby improving overall plant efficiency. Exhibit 8 shows multiple examples of heat rate improvements achieved by coal pulverizer upgrades or changes at individual, "real world" plants. Additional information on these improvements can be found in the associated referenced material.

Exhibit 8 Coal Pulverizer Heat Rate Improvement Examples

Corrections	Plant Information	Heat Rate Improvement	Annual Fuel Savings	Ref.
Decrease fuel rejects due to pulverizer clearance and setting. Decrease fly and bottom ash unburned carbon by 50%. Decrease primary air flow by 50%	400 MW, 10,500 Btu/kWh	75 Btu/kWh	$204,750	(7)
Performance enhancements (classifier reconfiguration, improved air flow distribution and accuracy, adjusting grinding spring tensions, etc.)	Not available	100 – 400 Btu/kWh	Not available	(9)
ATRITA Pulverizer system upgrade to reduce LOI and increase fineness	450,000 lb/hr steam	25 – 50 Btu/kWh*	Not available	(10)
Combustion Optimization System retrofit	200 MW	22 Btu/kWh**	Not available	(11)
** Based on estimations* ***Calculated based on 0.22% efficiency gain*				

3.6 Technical Analysis

To determine the potential efficiency gains associated with upgrading the coal pulverizers and ancillary equipement, two hypothetical power plants were examined. These plants, described above in Section 2, provide two diverse examples, giving a better representation of the potential heat rate benefits.. The first plant, Plant A, is assumed to be constructed in 1968, and utilizes a ball mill style pulverizer, and the other, Plant B, was built in 1995 with a MPS style pulverizer. As detailed above, both plants have a net output of 550 MW and burn bituminous coal.

Older plants tend to use ball mill style pulverizers; however, it is estimated that MPS style vertical spindle roller mills make up 70 percent of the commercial pulverizers deployed in today's coal-fired generation fleet. (12) The original MPS design came to the U.S. through Babcock & Wilcox (B&W) with the first commercial installation in 1973. (13) The most common size of the B&W pulverizer is the MPS 89 model. Alstom has since made an MPS-style pulverizer which is equivalent to the MPS 89, as well. Therefore, an MPS-style pulverizer will be used in the upgrade.

Given the information above, the following assumptions were made for the baseline plant:

Exhibit 9 Plant Baseline Assumptions

Plant	Year Built	Net Output, MW	Coal Pulverizer
Plant A	1968	550	Ball Mill
Plant B	1995	550	First Generation B&W MPS 89

For the retrofit cases, the pulverizers in both Plants A and B are replaced with updated B&W Vertical Roll Wheel Pulverizers. These second generation MPS pulverizers include increased life on wear parts, lower pressure drop, and the ability to maintain capacity through the wear cycle of the pulverizer. (14) This pulverizer is also assumed to be outfitted with "S-type" classifiers from SAVvy Engineering as well as combustion optimization and performance enhancements.

Plant A will benefit from a more efficient pulverizer technology, in addition to advances and upgrades provided by the new ancillary equipment. Plant A would have a higher heat rate reduction, given the age of the plant and the initial heat rate.

Plant B is assumed to have first generation MPS 89 technology. Given that Plant B is already using a more efficient mill than Plant A, coupled with its younger age and better initial heat rate, Plant B will benefit less from the upgrades assumed in the Plant A retrofit case.

Consistent with the performance improvements reported in Exhibit 8 and the assumptions above, it was expected that the following heat rate improvement ranges are attainable for Plants A and B (Exhibit 10).

Exhibit 10 Coal Pulverizer Plant Heat Rate Improvements

Plant	Previous Heat Rate, BTU/kWh	Heat Rate Improvement Range, BTU/kWh	New Heat Rate, BTU/kWh	Improvement Range (%)
Plant A	10,559	250 – 300	10,259 – 10,309	2.37 – 2.60
Plant B	9,680	50 - 100	9,580 – 9,630	0.52 – 1.03

3.7 Financial Analysis

The upgraded pulverizer was costed at $14.12 million, and discussions with industry sources and vendors indicated that an increase in capital cost of 10 percent would account for the advanced classifier, combustion optimization system, and new pulverizer. Therefore, the table below is the derived capital costs including the 10 percent increase due to new technology, expressed in 2012 dollars. In the case of both plants, this equates to a total cost of $34/kW.

Exhibit 11 Coal Pulverizer Capital cost

Capital Cost	$ (2012)
Pulverizers and ancillary equipment	$15.69 Million
Labor Costs	$2.04 Million
Freight to site	$0.73 Million
TOTAL	**$18.46 Million**

Exhibit 12 is a simplified return on investment (ROI) calculation showing the range of payback required, given the heat rate improvements listed in Exhibit 10 and the assumptions below. The payback period is defined as the length of time (in years) the unit needs to operate until the increase in capital expenditure is outweighed by the annual savings in fuel cost. It should be noted that this calculation is very dependant on both the cost of fuel and the capacity factor assumptions for the facility. For example, if the facility runs significantly less than the 85 percent of hours per year assumed, the payback period could double or triple.

Exhibit 12 Coal Pulverizer Payback Period

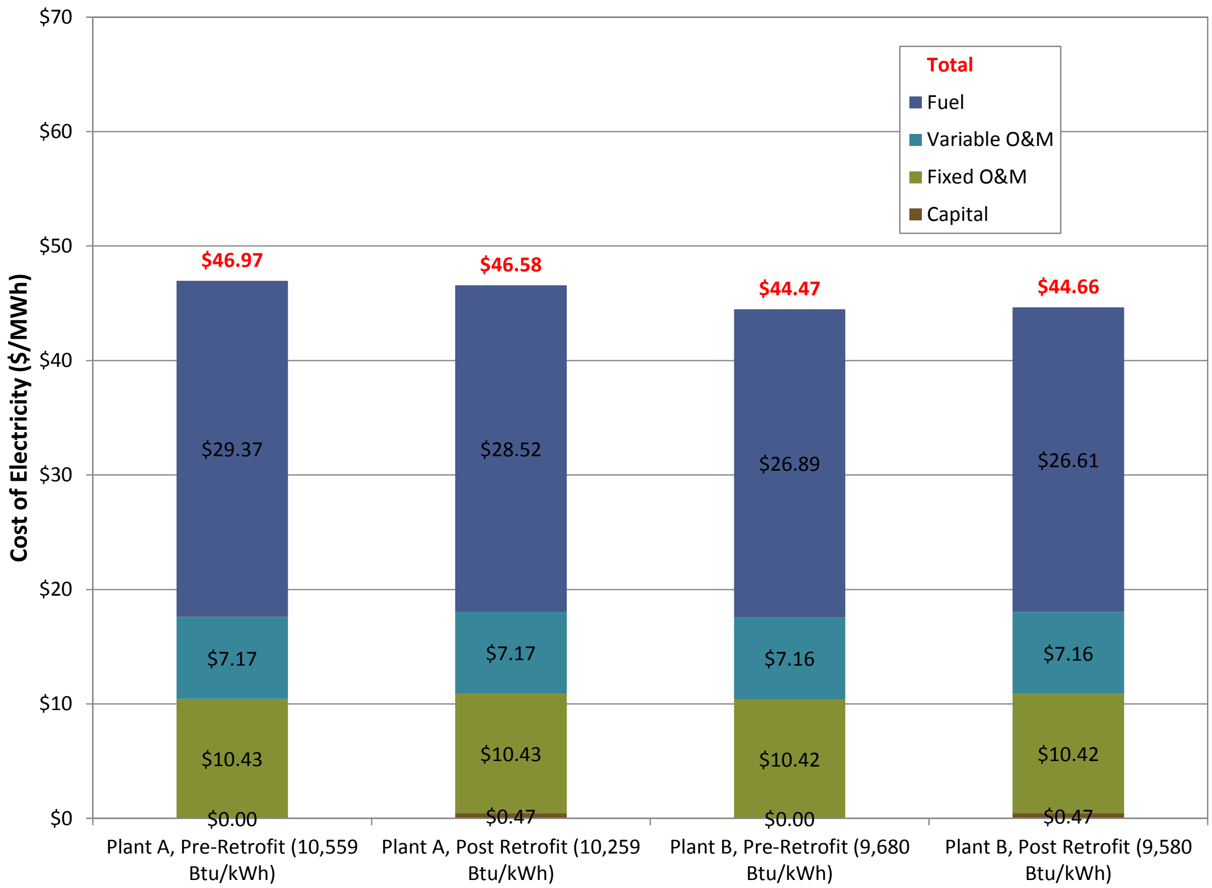
	Plant A 1968 Ball Mill			Plant B 1995 MPS 89		
Heat Rate Improvement (Btu/kWh)	Base	250	300	Base	50	100
TOTAL (STEAM TURBINE) POWER, kWe	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**
Net Plant Efficiency (HHV)	32.32%	33.11%	33.27%	35.26%	35.44%	35.63%
Net Plant Heat Rate, Btu/kWh	10,559	10,309	10,259	9,680	9,630	9,580
As-Received Coal Feed, lb/hr	497,810	486,023	483,666	456,369	454,012	451,654
Total Fuel HHV Input, MMBtu/hr	5,807	5,670	5,642	5,324	5,297	5,269
Coal savings MMBtu/hr		137.50	165.00		27.50	55.00
Coal savings $/year		$2,674,014	$3,208,816		$534,803	$1,069,605
Capital Cost		$18,460,000	$18,460,000		$18,460,000	$18,460,000
Payback (years)		**7**	**6**		**35**	**17**

Assumptions:

1) 11,666 Btu/lb coal
2) 85% capacity factor
3) $2.61/MMBtu Coal price
4) NOx is controlled to 0.07lb/MMBtu for all cases.

Exhibit 13 shows first-year cost of electricity (COE) given Plant A and B both pre-retrofit and post-retrofit with the highest heat rate improvement for both plants: 300 Btu/kWh (A-300) for Plant A, and 100 Btu/kWh (B-100) for Plant B.

Exhibit 13 Coal Pulverizer First-Year Cost Of Electricity



Fixed operation and maintenance (O&M) costs remain the same, since no labor additions would be required. While it was anticipated that variable O&M would decrease due to reduced maintenance requirements for the new equipment, the magnitude of change was expected to be negligible. The first year COE changes are small for both cases: Plant A sees a savings of $0.39/MWh, a 0.8 percent decrease in COE. It is interesting to note, however, that the COE increases slightly – by $0.19/MWh, or 0.4 percent – for Plant B. This is the result of the relatively small increase in efficiency for that plant compared to the cost of the pulverizer and given the one-year financing period. The breakdown in COE cost is detailed in Appendix A.

3.8 Conclusion

Coal pulverizers are easy targets for upgrades that will enhance a plant's heat rate in older plants that use ball mill type pulverizers. In plants with high LOI, a new pulverizer system can allow the plant to improve its heat rate and raise efficiency. In the case of Plant A, the efficiency was improved by roughly 1 percentage point to 33.3% on a HHV basis. This efficiency improvement will not only lead to reduced fuel costs, but also reductions in CO_2 emissions of 2.2 to 2.8 percent over existing operation.

In newer plants, the likely existence of more modern pulverizers means there is less of an opportunity for improvement in efficiency, and there may not be enough efficiency to be gained through improving coal pulverizers to justify the investment.

Exhibit 14 lists Plant A and B's original CO_2 output, and their new CO_2 output with the retrofit discussed in this study. The CO_2 emissions below are based on NETL's Bituminous Coal Baseline report Case 9. (4)

Exhibit 14 Coal Pulverizer CO_2 Emission Reduction Summary

Plant	Heat Rate, Btu/kWh[viii]	Pre-retrofit CO_2 Emissions, Million tonne/yr[ix]	Post-retrofit CO_2 Emissions, Million tonne/yr[ix]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A – Lower Bound	10,309 (250 reduction)	3.93	3.84	0.09 (2.2%)
Plant A – Upper Bound	10,259 (300 reduction)	3.93	3.82	0.11 (2.8%)
Plant B – Lower Bound	9,630 (50 reduction)	3.60	3.59	0.01 (0.3%)
Plant B – Upper Bound	9,580 (100 reduction)	3.60	3.57	0.03 (0.8%)

4 Analysis 2: Steam Surface Condenser

The condenser is arguably the most important section in the heat cycle, as it is where the largest energy loss in the Rankin cycle occurs. (15) The function of the condenser is to condense steam that is exiting from the steam turbine exhaust. For the purposes of this study, steam surface condensers were evaluated. Steam surface condensers use cooling water to pass through tubes in the condenser, allowing the steam to condense and fall into a well where it is pumped and reheated to be sent through the feedwater heating system. This style is typical for both new and existing coal-fired power plants.

[viii] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "250 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 250 Btu/kWh and the power plant is more effiecient.

[ix] Annual emissions assume a capacity factor of 85%.

4.1 Technology Advances

Condensers have been engineered over time to reduce pressure, prevent leakage, and increase heat transfer. These three factors play a major role in improving the efficiency of the condenser, and therefore the plant.

4.1.1 Pressure Reduction

Condenser pressure plays a significant role in heat rate improvement. If the pressure is too high, back pressure is placed on the turbine, reducing its efficiency; however, deploying vacuum pumps in the condenser will reduce back pressure on the turbines and increase condensation. One source cites that improvements in exhaust vacuum by 0.4" Hg can reduce turbine steam consumption by 1.1 percent, and can increase efficiency from 0.24 to 0.4 percent. (16) A power plant thermal cycle modeling analysis tool called PEPSE was used to analyze a 525 MW plant and showed that for each 0.1 in Hg rise in back pressure, a heat rate penalty of 0.17 percent resulted. (17)

Another phenomenon known as air binding can occur when air in the condenser is surrounded by steam/water with no clear path for the air removal, causing it to be trapped in the condenser. Newer plants have a better understanding of steam distribution, condensation paths, and cooling areas due to computational fluid dynamic (CFD) models. Due to the lack of CFD modeling and/or poor engineering, older plants tend to suffer from this phenomenon. Through current CFD modeling, geometric restructuring can alleviate this problem. (18)

4.1.2 Air/Water Leakage

Air and water leakages can occur in many forms: air leaking into the condenser from the outside, water leaking from the condenser to the outside, and water leaking from the tube side into the shell side. Leakages can be caused by corrosion and erosion in the shell or tubes. No systems are leak proof, and a typical rule of thumb sets the normal air in-leakage rate at 1 scfm per 100 MW. (19)

Efficiency gain analysis is not being measured solely by economics; however, tube leakage can be prevented by using protective coatings instead of tube replacement. Both options vary in cost, which is a factor that needs to be considered before implementation. (20)

4.1.3 Heat Transfer Improvement

Heat transfer can be reduced due to fouling on the tubes. Deposits tend to accumulate on the tubesheets, reducing heat transfer over time. Fouling can come in multiple types such as deposits (silt, mud), scaling (calcium, manganese), microbiological, macro-fouling (shells, clams) and corrosion. (21) Heat rate increases of up to 2 percent are not uncommon for condensers with severely fouled tubes, and some plants have reported upwards of 20 MW being recovered from the removal of severe deposits/scaling. (22) Heat rate can also be dependent on the tube material. Older plants used Admiralty Brass (a type of brass with zinc and tin) and copper. Newer plants tend to use stainless steel or titanium.

A ball tube cleaning system is an automatic, online means of continually cleaning the inside diameter (ID) of tubes to reduce microbiological growth and scaling. Some ball tube cleaning systems claim up to a 4 percent increase in annual power generation. (23) However, most of the increase in generation is gained through a reduction of maintenance down time rather than through an efficiency gain.

4.1.4 Total Improvements

Exhibit 15 shows multiple examples of improvements to the three key areas of the condenser that were made based on upgrades at individual plants. Additional information on these improvements can be found in the documents referenced in the table.

Exhibit 15 Condenser Improvement Examples

Corrections	Plant Information	Heat Rate Improvement	Air In-leakage reduction	Condenser Pressure Improvement	Ref.
Replaced Admiralty brass and copper tubing with stainless steel	Not available	1 – 2%	75 SCFM	0.7” Hg	(24)
Repaired holes in condenser and added leak detection equipment	445 MW oil fired plant	Not available	35 SCFM	0.539” HgA	(25)
Reconfigured Condenser shell side arrangement to reduce air binding	Not available	Not available	Not available	1.0” HgA and 0.6” HgA[x]	(18)
8 leaks were identified and repaired based in sensor information	850 MW coal-fired plant	200 Btu/kWh	Not available	Not available	(26)
Correcting air in leakage, fouling, and changing air removal equipment	Not available	2%	Not available	Not available	(27)
Condenser Tube maintenance plan	Not available	30 – 70 Btu/kWh	Not available	Not available	(28)

4.2 Technical Analysis

Older plants tend to use copper or Admiralty tubing for their condensers. Stainless steel tubing was not introduced until the 1970s, and, as of 1998, only 45 percent of freshwater-cooled

[x] LP and HP condenser sections, respectively

condensers contained stainless steel tubing. (29) Stainless steel is the most cost-effective tubing; however, plants that focus on long lifetimes and reduced maintenance opt for titanium tubing which lasts longer.

The condenser upgrade technical evaluation assumes the same two power plants described in Section 3.6 above. One plant was assumed to be constructed in 1968 with copper/Admiralty brass tubes, and the other was assumed to be built in 1995 with stainless steel tubes. Both 550 MW plants used liquid ring vacuum pumps for non-condensable removal and burn bituminous coal.

Using the information above, Exhibit 16 lists the assumptions that were made for the baseline plants.

Exhibit 16 Plant baseline assumptions

Plant	Year Built	Net Output, MW	Condenser Pressure (in Hg)	Condenser Tubes
Plant A	1968	550	2.75	Copper / Admiralty
Plant B	1995	550	2.25	Stainless Steel

For the retrofits, the condensers in both Plants A and B are replaced with titanium tubing coated with the Nuclear Energy Institute's (NEI) NANOMYTE SuperCN coating, a unique hydrophobic coating to increase heat transfer coefficient by approximately 30 percent. (30) Based on a personal communication with NEI technical staff, this heat rate transfer increase can decrease condenser pressure by approximately 5 percent.[xi] The retrofit will include additional flow baffles, and geometric restructuring to eliminate air pockets, as indicated by a 3-D CFD model. (31) The retrofit will include correcting in-leakage paths and adding a ball-tube cleaning system to maintain heat-transfer and cleanliness.

Plant A benefits the most from the condenser upgrade, particularly because of the geometric restructuring. CFD modeling would not have been available at the time of installation, so air pockets and air binding locations would likely be found and corrected during the upgrade. Also, this restructuring would help to find and correct in-leakage pathways in the 45-year-old condenser shell.

Plant B is assumed to have stainless steel tubing and fewer maintenance requirements. The retrofit benefits will not be seen as drastically as in Plant A, since stainless steel tubing has greater heat transfer and resistance to fouling than copper tubing; however, hydrophobic titanium tubing will increase heat transfer further.

[xi] Personal Communication, 04/11/2013 between Steve Herron and NEI.

Given the assumptions above and using engineering judgment, the following heat rate improvement ranges are attainable for baseline Plant A and B.

Exhibit 17 Plant Heat Rate Improvements

Plant	Previous Heat Rate, BTU/kWh	Heat Rate Improvement Range, BTU/kWh	New Heat Rate, BTU/kWh	Heat Rate Improvement Range, %
Plant A	10,559	264 – 370	10,189 – 10,295	2.5 – 3.5
Plant B	9,680	97 – 194	9,486 – 9,583	1 – 2

4.3 Financial Analysis

Capital costs were derived from multiple sources as listed in Exhibit 18.

Exhibit 18 Installation Cost

Capital Cost	$ (2012)	Reference
Condenser Retubing	$6.5 Million	(32) - Scaled from 300 to 550 MW converted to 2012 $
Coating	$700,000	Estimated based on 50% of cost to recoat existing condensers
Ball Tube Cleaning System	$350,000	(33)
Geometric Reconfiguration	$500,000	Estimated based on 5% of new construction budget
Labor Costs, Freight to Site, and other miscellaneous expenses	$1.37 Million	Estimated at 17% based on typical EPC factors
TOTAL	**$9.42 Million**	

Exhibit 19 is a simplified payback period calculation showing the range of payback periods required given the heat rate improvements listed in Exhibit 17 and the assumptions in Exhibit 16.

Exhibit 19 Simplified payback period calculation

	Plant A Copper / Admiralty Tubes			Plant B SS tubes		
Heat Rate Improvement (Btu/kWh)	**Base**	**264**	**370**	**Base**	**97**	**194**
TOTAL (STEAM TURBINE) POWER, kWe	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**
Net Plant Efficiency (HHV)	32.32%	33.15%	33.50%	35.26%	35.62%	35.98%
Net Plant Heat Rate, Btu/kWh	10,559	10,295	10,189	9,680	9,583	9,486
As-Received Coal Feed, lb/hr	497,810	485,363	480,366	456,369	451,796	447,223
Total Fuel HHV Input, MMBtu/hr	5,807	5,662	5,604	5,324	5,271	5,217
Coal savings MMBtu/hr		145.20	203.50		53.35	106.70
Coal savings $/year		$2,823,758	$3,957,540		$1,037,517	$2,075,034
Capital Cost		$9,418,000	$9,418,000		$9,418,000	$9,418,000
Payback (years)		**3**	**2**		**9**	**5**

Assumptions:

1) 11,666 Btu/lb coal

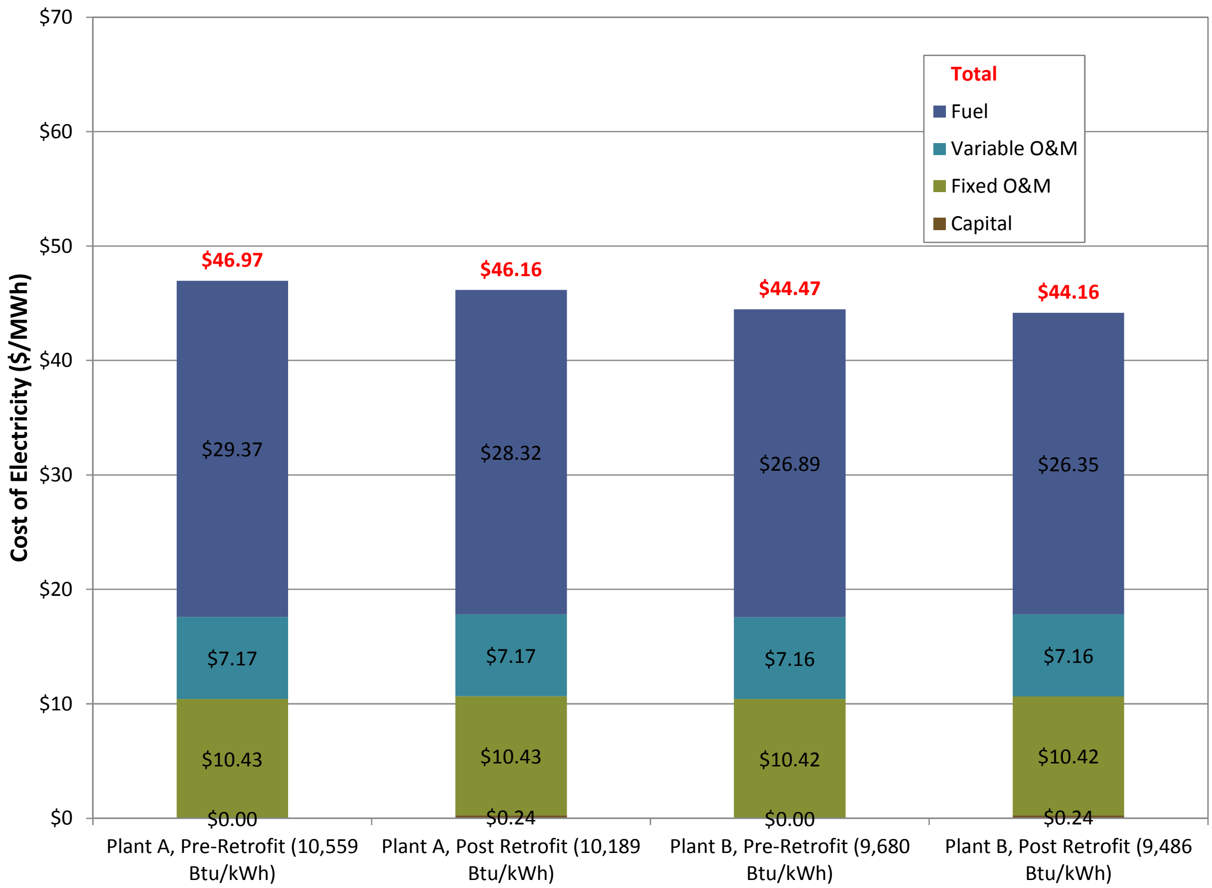
2) 85% capacity factor

3) $2.61/MMBtu Coal price

The payback period is defined as the length of time (in years) the unit needs to operate until the increase in capital expenditure is outweighed by the annual savings in fuel cost. The payback period for Plant A seems reasonable at two-to-three years. Plant B's payback period of five-to-nine years is slightly less attractive, because the long timeframe would yield minimal return.

Exhibit 20 shows first-year COE for Plant A and B. The results show both pre-retrofit and post-retrofit data, with the highest heat rate improvement for Plant A of 370 Btu/kWh (A-370) and Plant B of 194 Btu/kWh (B-194).

Exhibit 20 First-Year Cost Of Electricity



Fixed O&M costs remain the same pre- and post-retrofit, because the O&M costs would decrease slightly for the retrofit case as mechanical tube cleaning offline would be eliminated; however, additional ball tube cleaning system upkeep would be required. What is not reflected in this study is the reduced down time due to condenser maintenance. Mechanical cleaning of condenser tubes can take weeks.

Plant A has a potential savings of $0.81/MWh, and a payback period of two-to-three years. Plant B's cost savings of $0.31/MWh are reduced, but are still promising. They do, however, have a longer payback period of five-to-nine years. For more information on the COE and cost breakdowns, see Appendix B.

4.4 Conclusion

Condensers are a prime area for efficiency increases in a plant with multiple, readily available technology options. This efficiency increase will reduce in-leakage, increase heat transfer, and reduce pressure. The two-to-three-year payback and an increase in heat rate of 2.5 – 3.5 percent range is motivation for older plants operating with their original condensers to upgrade. Newer plants will also see a boost in heat rate, but are likely to have a longer payback period.

Condensers are important heat exchangers and are worth the upgrades that are required to increase efficiency while reducing down time and maintaining O&M costs.

Exhibit 21 shows the improvement in CO_2 emissions associated with condenser upgrades, for the case studies considered for this analysis.

Exhibit 21 Condenser Upgrade CO_2 Emission Reduction Summary

Plant	Heat Rate, Btu/kWh[xii]	Pre-retrofit CO_2 Emissions, Million tonne/yr[xiii]	Post-retrofit CO_2 Emissions, Million tonne/yr[xiii]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A – Lower Bound	10,295 (264 reduction)	3.93	3.83	0.10 (2.5%)
Plant A – Upper Bound	10,189 (370 reduction)	3.93	3.79	0.14 (3.6%)
Plant B – Lower Bound	9,583 (97 reduction)	3.60	3.57	0.03 (0.01%)
Plant B – Upper Bound	9,486 (194 reduction)	3.60	3.53	0.07 (1.9%)

4.5 Future Advances

Condensers are one of the main forms of heat transfer in a power cycle, and heat transfer technology continues to advance. For example, future condensers could see impregnated nanotextured surface tubes for enhanced condensation and heat transfer. (34) This technology is the next generation of coatings, and it increases water droplet formation on tubes and makes the water fall from the tubes faster, increasing heat transfer. This gives this technology significant potential as it is estimated that 70 percent of total heat transfer resistance comes from slow-moving fluid coming into contact with the tube wall. (35)

Another location of advancement is new generation ball tube cleaning systems. Some systems have a reputation for requiring high maintenance cost. Future advances in this system could further decrease O&M costs for condenser tube cleaning.

[xii] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "264 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 264 Btu/kWh and the power plant is more effiecient.

[xiii] Annual emissions assume a capacity factor of 85%.

5 Analysis 3: Steam Turbine

The steam turbine is the primary power conversion component in a coal-fired plant. The thermal energy of the steam is converted to rotating mechanical energy in the steam turbine interior. A steam turbine generator then converts the mechanical energy to electrical energy. (15) This improvement evaluation is dedicated to the thermal-to-mechanical power conversion component of the Rankine cycle. The boundaries for the evaluation are from the admission valves to the condenser connection.

5.1 Technology Advances

Steam turbines have been engineered over time to improve steam path, minimize steam leakage around blades, improve steam seals, minimize thermal stresses, and utilize corrosion and heat resistant materials. Modern retrofits have combined turbine component improvements in order to provide an overall steam turbine upgrade that restores and enhances total efficiency. These upgrades also reduce maintenance costs, lower fuel consumption, improve reliability, reduce emissions, and increase capacity and revenue.

5.1.1 Turbine Blade Maintenance: Abradable Coatings

An abradable coating, normally of a metal alloy composition, is a spray coating applied to the standard turbine seal segments. The coating reduces leakage flow by decreasing tip clearances. In the event of a rub, the sharp edge of the rotor seal, which is harder than the abradable coating material, will have minimal damage or wear. Abradable coatings have been shown to provide performance improvements of 0.1 to 0.2 percent. (36)

5.1.2 Turbine Seals

Between the turbine rotor and stator, radial clearances are necessary to ensure virtually frictionless rotational movement. Due to the pressure differences across the clearances, flow leakage losses are present, which reduces turbine efficiency. The leakage can be counteracted by sealing. Conventional labyrinth seals reduce the radial gaps with a multiple sealing fin configuration and can be improved with coatings, spring backed seals, and retractable seal packings.

Brush Seals

Brush seals are relatively new for steam turbine applications. They have been utilized in turbomachinery for several years, but in large steam turbine applications various challenges still persist. Long term performance and longevity of brushes on conventional spring-backed seal segments are of concern, particularly related to wear during startup conditions. A model for brush seal performance degradation was developed by combining initial wear testing, existing mid-term wear data, and experience-based long term data.

The model and actual observations have shown that brush seals are capable of adapting significantly to varying operation conditions. Brand new brush seals provide as much 90 percent leakage flow reduction compared to conventional labyrinth seals. There is some initial wear which results in increased seal leakage, but it is sustainable and below conventional labyrinth seal leakage levels. A sustainable gain of up to 500 kW output for a large HP turbine fitted with brush seals in the gland steam system is achievable compared to a turbine with labyrinth seals. (37)

Guardian Packing and Vortex Shedder Seals

Turbo Parts, LLC has designed Guardian packing rings to replace any conventional Original Equipment Manufacturer (OEM) packing rings without modifications to either the holder or the rotor. The packing ring is suitable for any labyrinth seal ring application. During transient events, the patented extended posts within the seal ring are meant to contact the rotor first to prevent damage to the conventional teeth and rotor.

In addition to the Guardian packing, Turbo Parts, LLC has designed a Vortex Shedder Seal. The seal reduces the pressure drop across any labyrinth seal by creating a pressure barrier from the vortices. The lower pressure drop means less seal leakage and higher efficiency. The Vortex Shedder Seal has shown an increase in efficiency by 1.5 percent to 4.5 percent. (38) Combining the Guardian packing and Vortex Shedder Seal has shown improved reliability and an increase in turbine efficiency by 2 percent to 5 percentage points. (39)

5.1.3 Turbine Blade Retrofit

Existing operating high pressure and intermediate pressure turbine sections can be upgraded by replacing select blade rows with advanced blading. Siemens has a design, 3DS, which is approximately 2 percent better on stage-to-stage efficiency than their former T4 blades. (40) They incorporate 3D air foil design, twisted blades, and 3D design for the end-walls to reduce secondary losses. Blade rows can be replaced individually, but are typically done in combination with other turbine component replacements during major improvements.

According to Siemens, with advanced blading, a 20-year-old steam turbine in the 600 MW to 700 MW range, is capable of increasing the turbine efficiency by a total of about 4 percentage points and the electrical output by about 5 percentage points. (36)

5.1.4 Dense-Pack Turbine Blades

In the early 1990’s, GE produced an Advanced Vortex bucket and diaphragm retrofit known as Advanced Design Steam Path (ADSP). With more than 40 ADSP packages currently in operation, the ADSP program provided a good experience base for what has become known as the Dense Pack retrofit. ADSP incorporated some of the features now included in Dense Pack such as steam flow management, optimized packing clearances, and advanced shaft sealing. (41) The Dense Pack retrofit replaces steam turbine internal components to provide the most efficient steam path that will fit within an existing outer turbine shell. Features include the following:

1. New high efficiency, high pressure, or high pressure / intermediate pressure turbine rotor with increased number of stages
2. Optimized steam path diameter
3. New high efficiency diaphragms
4. New high efficiency first stage nozzle box plate or nozzle diaphragm

5. Lower bucket and nozzle solidity (decreased number of buckets and nozzles per stage)
6. New inner shell(s)
7. New shaft packing, packing heads, and steam inlet ring assemblies
8. Improved shaft and bucket sealing capability

These changes lead to significant reduction in flow-through velocity with a corresponding drop in profile losses, while improved blade aspect ratio reduces overall secondary losses. The lower velocities allow smaller pitch diameters, which are made possible by advances in rotor-dynamic technology. Developments in aerodynamics, manufacturing processes, advanced seals and leakage flow control also increase turbine efficiency. (42)

Each Dense Pack is custom designed for the specific turbine and steam flow conditions. Depending on the capabilities of the boiler, generator, and other components, it may be possible to boost heat input by as much as 17 percent. A conservative design case had a 12 percent flow increase. This resulted in 1.4 percent efficiency increase at 100 percent maximum continuous rate (MCR) and 1.4 percent increase in power generating capacity. At 112 percent MCR, the efficiency was increased 1.2 percent, but resulted in 13.3 percent power generation increase. (43)

The Dense Pack design is suitable over a range of steam turbines. An upgrade was conducted at a 390 MW plant where the HP/IP turbines were replaced with the Dense Pack design as well as a new low pressure (LP) rotor. The result was a 5 percent increase in HP turbine efficiency. Additionally, the intermediate pressure (IP) turbine efficiency increased by 4 percent, and LP turbine efficiency increased by 2.5 percent. This result showed an increase in the highest achievable gross generation from 360 MW to 371 MW. (42)

Similar to GE's Dense Pack design, Siemens has a retrofit design package that includes new rotors, inner casings, and high efficiency stationary and rotating blades for the Westinghouse Building Block 44; a sub-critical fleet of steam turbines built before the 1990s. A summary of the packages and improvements are listed in Exhibit 22. Total efficiency gains range from 1.9 percent to 5.5 percent. An additional 20 MW could be generated in addition to the original 365 MW. (44)

5.2 Additional Improvements

A number of potential additional improvements can also be made to improve performance. A selection of those options are listed below.

5.2.1 Partial Arc Admission

In full arc admission, all regulating valves open, but only at a percentage of their full opening. With load increase, they all open more fully. Partial arc admission allows the steam to enter per valve opening in a sequential manner, so as load is increased, more valves open to admit steam. The change reduces throttling losses through the valves. The flexibility of the partial arc, as opposed to the full arc, offers better efficiency and reliability for plants that operate over a wide range of load conditions. A change from full arc to partial arc should only be considered if the plant operating philosophy has changed to variable load operation.

Siemens has provided a retrofit package that can be implemented for full arc or partial arc admission with improved steam flow characteristics. By improving the steam flow through the admission valves along with additional improvements to turbine blades and seals (see Exhibit 8), HP efficiency can be improved by 8-10 percent. (44)

5.2.2 Backpressure Turbogenerators

Conventional, power-only steam turbine installations maximize efficiency by maximizing the pressure drop across the turbine. The steam turbine exhausts at near-vacuum pressures and can generate electricity with overall plant efficiencies of approximately 40 percent. (45)

Industrial facilities utilizing steam may produce higher pressure steam than what is required by process requirements. When steam is produced at a higher pressure than is demanded by the process requirements, it passes through pressure-reducing valves (PRVs) to reach the appropriate pressure. This energy is wasted as friction and heat. A backpressure steam turbine can perform the same pressure-reducing function as the valves, while converting the energy into electrical energy. The rotor is attached to a shaft that is coupled to an electrical generator to produce power.

Backpressure turbogenerators should be considered when a PRV has a constant steam flow of at least 3,000 pounds per hour and when the required steam pressure drop is at least 100 psi. Adding a backpressure turbogenerator can improve overall plant efficiency higher than the 33 percent average of U.S. grid generators. However, they add a level of complexity in terms of steam system control and a risk of turbine water induction at low or partial loads. (45)

5.2.3 DC Corona at the Condenser Neck

In 1999, the Electric Power Research Institute (EPRI) conducted a study concerning the effects of electrical charge and turbine efficiency. Electrodes were placed across the exit of the LP turbine and the entrance of the condenser to displace the electrical charge the steam had accumulated while passing through the turbine. (46) The result showed the potential for improvement.

Some of the major contributors to efficiency loss in a fossil plant are associated with nucleation of moisture from superheated steam, formation, and release of liquid films on turbine surfaces on a microscopic level, and flow of moist steam into the turbine exhaust and condenser. These wetness losses cause friction loss and can lower turbine efficiency up to 8 percent.

5.3 Total Improvements

Exhibit 22 shows multiple examples of improvements to the steam turbine. Actual plant retrofits are listed with their complete package of improvements and testing results. Efficiency gains for HP, IP, and LP sections are stated individually where applicable.

Exhibit 22 Steam Turbine Improvement Examples

Improvements	Plant information	Increase in Efficiency % (HP section)	Increase in Efficiency % (IP section)	Increase in Efficiency % (LP section)	Total Efficiency Gain	MW Added	Ref
Abradable Coating Seals	Siemens 2005				0.1 - 0.2 %		(40)
3D Blading Technology	Siemens 2005				2 %		(40)
Advanced Blading	Siemens 600-700 MW Built before 1990				4 %	5%	(36)
Brush Seals	Siemens 2006					0.5	(36)
Guardian Packing & Vortex Shedder Seals (operates with labyrinth seals and Vortex Shedder Seals)	Hitachi 2008				2 - 5 %		(38)
Vortex Shedder Seal	Turbo Parts, LLC, 2011				1.5 - 4.5%		(39)
Full Arc Admission Inlet, Improved Flow Technology Eliminate the Separate Nozzle Chambers & Nozzle Blocks Eliminate the 180 deg steam turn around to the HP Blade Path Eliminate the Impulse Control Stage 3D Blading Technology Fully Integral Inner Casing Advanced Sealing Technology throughout (Spring Back and Retractable seals)	Siemens 365 MW Built in 1979 Retrofit in 2004	8 - 10%	2 - 4%		4.1 - 5.5%	15-20	(44)
Eliminate riveted shrouds on front-end blading Eliminate riveted shrouds and lashing wires on large LP blading Single inner casing with moisture removal features Increase resistance to stress corrosion cracking (SCC) Increase resistance to high cycle fatigue 8.7 inches of HgA exhaust pressure limit at high loads 10-year inspection interval Torsional compatibility with existing generator rotor	Siemens, 365 MW Built in 1979, Retrofit in 2004				1.9 - 2.2%	7 - 8	(44)
HP/IP Turbine replaced 2 Double flow LP Turbines replaced (from 30" to 34")	TurboCare, 580 MW, Built in 1974 Retrofit in 2002	7% (HP & IP)		5%		27	(47)
Steam seal package Standard labyrinth packing rings Retractable packing rings Brush Seals Conventional blade and brush-tip seals	375 MW, Built in 1970s, Retrofit in 2004					2.3	(47)
Dense Pack	GE 2000	1.5 - 3%			1.4%	1.4%	(41) (43)
Dense Pack and LP Turbine	GE, 365 MW, Retrofit in 2005	5%	4%	2.5%	1.5%	11	(42)

5.4 Technical Analysis

The steam turbine upgrade technical evaluation assumes the same two power plants described in Section 3.6 above. Exhibit 23 lists the assumptions that were made for the baseline plants, as well the steam turbine information for each unit.

Exhibit 23 Plant baseline assumptions

Plant	Year Built	Net Output, MW	HP Steam Path Efficiency, %	IP Steam Path Efficiency, %	GE Steam Turbine Technology
Plant A	1968	550	88-90	89	Free Vortex Design
Plant B	1995	550	91-93	94	Second Generation Advanced Vortex and Integral Covered Buckets with Optimal Clearance

For the retrofit cases, the steam turbines in both Plants A and B are replaced with GE's Dense Pack turbine package. Since the Dense Pack design combines multiple steam turbine internal replacements while maintaining the existing outer turbine shell, it provides an opportunity for a direct comparison in aging plants.

In the HP section, nozzle and bucket aerodynamic profile losses, secondary flow losses, and leakage losses account for roughly 80 to 90 percent of the total stage losses. Hence, to ensure high-efficiency turbine design, it is necessary to use highly efficient nozzle and bucket profiles and to minimize leakage flows without sacrificing turbine reliability. From the 1960's to the 2000's, GE made incremental design improvements to the HP steam path efficiency to improve from 88 percent to 95 percent. (43)

IP turbine efficiencies were similarly improved from 89 percent to nearly 97 percent. Overall, the upgraded turbine will use less steam per MW of power produced. The reduced steam path efficiency translates into an equivalent reduction in heat rate. (42)

Plant A will have a best case scenario of 7 percent HP steam path efficiency increase and an overall steam flow improvement of 5.5 percent, assuming the existing steam turbine is the original 1968 design. Likely, it was upgraded before the 40-year life expectancy period expired. However, if the turbine was upgraded to an early 1990's steam turbine model, there is still an opportunity to increase efficiency as shown with the Plant B scenario.

Plant B will have a best case scenario of 4 percent HP steam path efficiency increase and an overall steam flow improvement of 3 percent by retrofitting to the current Dense Pack technology with advanced sealing. This is lower than Plant A, but is expected since Plant B is newer and is likely equipped with better technology.

Additionally, the new efficient steam path eliminates solid particle erosion, allowing the units to operate for longer periods of time before additional major overhauls. Initial experience indicated that the retrofit resulted in a 75 percent reduction in degradation attributed to solid particle erosion. The expected time between internal repair or inspection is increased to ten or more years (41) from the typical five-to-eight years. (48)

Given the assumptions above and using engineering judgment, Exhibit 24 shows the heat rate improvement ranges that are are attainable for baseline Plant A and B.

Exhibit 24 Plant Heat Rate Improvements

Plant	Previous Heat Rate, BTU/kWh	Heat Rate Improvement Range, BTU/kWh	New Heat Rate, BTU/kWh	Improvement Range, %
Plant A	10,559	422 – 581	9,978 – 10,137	4 - 5.5
Plant B	9,680	145 - 290	9,340 – 9,535	1.5 - 3

5.5 Financial Analysis

Multiple retrofit options were discussed in Section 5.2, though many were eliminated due to insufficient data (DC corona), inappropriate application (backpressure turbogenerator), or because they were covered under the dense pack turbine upgrade. As mentioned earlier, backpressure turbines were not considered because current models only range in 50 – 2,000 kW sizes and are typically not used in generating facilities. (45) A large 2.8 MW backpressure turbine that was proposed by TurboSteam to Wausau-Mosinee Papermill Company in 2001 was estimated at $810,000. (49) Scaling from this reference point would make the cost unrecoverable for the plants considered in this analysis. Dense Pack turbine retrofit, as mentioned in Section 5.1.4 covers an array of potential turbine upgrades. Therefore, for the financial analysis, only the Dense Pack turbine retrofit is considered.

Retrofitting Plants A and B with GE’s Dense Pack turbine retrofit package would cost an estimated $8.2 million, based on costs found in the literature and scaled appropriately. (42) In the case of both plants this equates to $14.91/kW, making it both the least costly and most effective – in terms of performance gains – of the retrofits evaluated. The only potential downside to this upgrade choice could be a long down-time associated with retrofitting the turbine.

Exhibit 25 Installation Cost

Capital Cost	Capital Cost (2012 dollars)	Reference
Dense Pack Turbine	$7.2 Million	(42) – Scaled from 390 to 550 MW, and converted to 2012 dollars
Labor Costs, Freight to site, and other miscellaneous expenses	$1.0 Million	Estimated at 14 percent of material cost based on typical EPC factors
TOTAL	**$8.2 Million**	

Exhibit 26 is a simplified payback period calculation showing the range of payback required given the heat rate improvements listed in Exhibit 10. The construction period is one year, including lost revenue during the down time which equals the construction period. Additional assumptions are listed in Exhibit 12.

Exhibit 26 Simplified Payback Period Calculation

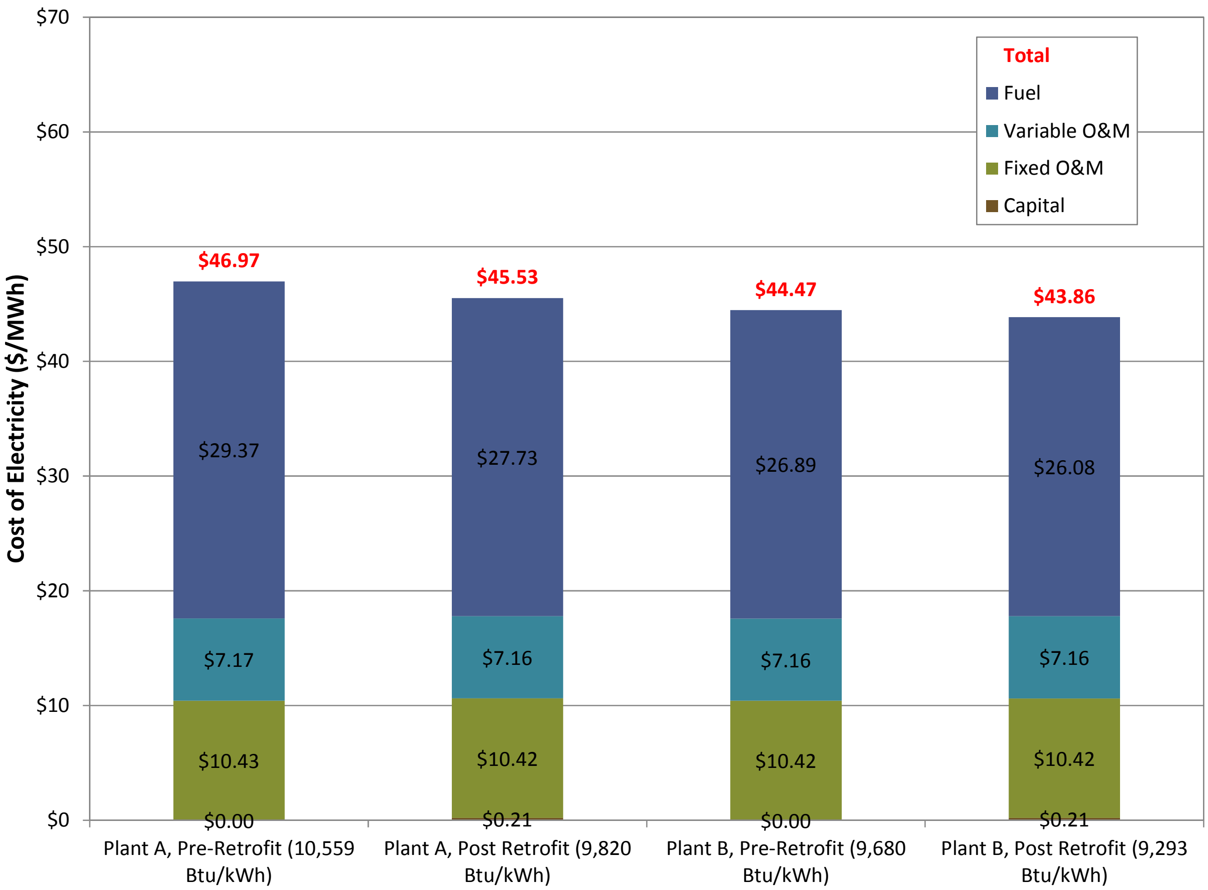
	Plant A Free Vortex Design			Plant B Second Generation Adcanced Vortex		
Heat Rate Improvement (Btu/kWh)	**Base**	**422**	**581**	**Base**	**145**	**290**
TOTAL (STEAM TURBINE) POWER, kWe	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**
Net Plant Efficiency (HHV)	32.32%	33.67%	34.21%	35.26%	35.79%	36.35%
Net Plant Heat Rate, Btu/kWh	10,559	10,137	9,978	9,680	9,535	9,390
As-Received Coal Feed, lb/hr	497,810	477,914	470,418	456,369	449,533	442,697
Total Fuel HHV Input, MMBtu/hr	5,807	5,575	5,488	5,324	5,244	5,165
Coal savings MMBtu/hr		232.10	319.55		79.75	159.50
Coal savings $/year		$4,513,735	$6,214,407		$1,550,928	$3,101,856
Capital Cost		$8,199,756	$8,199,756		$8,199,756	$8,199,756
Payback (years)		**2**	**1**		**5**	**3**

Assumptions:
1) 11,666 Btu/lb coal
2) 85% capacity factor
3) $2.61/MMBtu Coal price

The payback period is defined as the length of time (in years) the unit needs to operate until the increase in capital expenditure is outweighed by the annual savings in fuel cost. As described, the simplified payback period calculated for Plant A is between one-to-two years, while Plant B has a longer payback period of three-to-five years. Both of these payback periods are within the 5-year planning window for utilities, making them potentially viable depending on the operating philosophy of the utility and their view of the market. This upgrade would also extend the life of the turbine, and therefore the plant, which would also factor inot the decision making process.

Exhibit 27 shows first-year COE for Plant A and B. The results show both pre-retrofit and post-retrofit, with the highest heat rate improvements for both plants: 581 Btu/kWh for Plant A and 290 Btu/kWh for Plant B.

Exhibit 27 Steam Turbine Upgrade First-Year Cost Of Electricity



Fixed and variable O&M costs remain relatively the same pre- and post-retrofit. Not taken into consideration (due to modeling limitations) is the steam loss decrease by the new turbine seal system which is an additional financial gain. It is estimated that a 1 percent reduction in steam consumption saves around $47,000 annually. (16) Steam consumption occurs when steam passes through the turbine that isn't used to make energy (whether steam consumption is through the glands or due to governing the turbine).

Plant A has a savings of $1.44/MWh, a 3.1 percent decrease in COE. Plant B's cost savings of $0.61/MWh, or 1.4 percent, is less, but still more substantial than in any of the other retrofit opportunities evaluated. The breakdown of the COE costs are detailed in Appendix C.

5.6 Conclusion

The efficiency of an entire power plant is largely dependent on the efficiency of the energy conversion in the steam turbine. Many aging plants conducting normal maintenance now have an option to perform an overhaul of the steam turbine internals to install the latest technologies in blading and seals. Plants could see overall efficiency improvements of 1.5 to 5.5 percent, depending on the initial steam turbine efficiency. Major manufacturers such as GE and Siemens provide complete packages for their original equipment and also offer options for retrofitting other suppliers' turbines. Non-OEM suppliers can perform specific upgrades for advanced seal systems or blade replacements. All of these approaches aim to reuse as much existing equipment as possible such as bearings, bearing pedestals, outer casings, piping and supports. The overall goal is to provide improved reliability, performance, maintenance requirements, and emission levels comparable to a new steam turbine at a fraction of the cost.

Exhibit 28 lists CO_2 emission summaries for Plant A and Plant B for the retrofit discussed in this section.

Exhibit 28 Steam Turbine Upgrade CO_2 Emission Reduction

Plant	Heat Rate, Btu/kWh[xiv]	Pre-retrofit CO_2 Emissions, Million tonne/yr[xv]	Post-retrofit CO_2 Emissions, Million tonne/yr[xv]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A – Lower Bound	10,137 (422 reduction)	3.93	3.78	0.15 (3.8%)
Plant A – Upper Bound	9,978 (739 reduction)	3.93	3.72	0.21 (5.3%)
Plant B – Lower Bound	9,535 (290 reduction)	3.60	3.55	0.05 (1.4%)
Plant B – Upper Bound	9,340 (387 reduction)	3.60	3.50	0.10 (2.8%)

6 Analysis 4: Solar Feedwater Heater

Solar assisted feedwater heaters use solar thermal energy to heat the boiler feed water in place of extracted steam from the turbine. This allows that steam to be utilized to produce additional power in the turbine or produce the same power with reduced fuel consumption and emissions. The efficiency boost and overall costs to augment an existing power cycle with solar feedwater heating are evaluated in this section.

6.1 Technology Advances

In both solar thermal power systems and conventional power systems, heat is the mode of transport for energy. In a regenerative Rankine power cycle, bleed steam pulled from the steam

[xiv] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "422 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 422 Btu/kWh and the power plant is more effiecient.

[xv] Assumes annual capacity factor of 85%

turbine is used to preheat feedwater before it enters the boiler. This increases thermal efficiency at the cost of reducing the work output of the turbine due to reduced steam flow. The feedwater, heated in various stages, can be integrated with solar thermal systems to take advantage of an additional heat source. In doing so, the high-grade energy of the normally extracted steam can be utilized to perform work in the turbine. Furthermore, the amount of fuel burned can be reduced while maintaining the same power generation, thereby lowering emissions.

6.1.1 Peak Demand vs. Peak Solar Irradiation

Daily power demand in the United States follows a basic trend that rises during the early morning hours, steadies throughout the daylight hours and peaks in the early evening hours. Seasonal trends also affect the peak demand. During the hot summer months, commercial and residential air conditioning creates a higher peak in demand during the late afternoon. This would typically cause plants employing solar feedwater heating to require storage to make up for differences in peak demand and peak solar irradiation.

It is estimated that 15 percent of the total cost of construction for a solar thermal facility is attributed to the storage system. (50) However, a hybrid solar thermal generating plant evaluated in this study does not require storage since it operates the thermal system during daylight hours only to add to the power output. It is also assumed that the daily peak power demand and peak solar irradiation levels are similar.

6.1.2 Power and Efficiency Gains

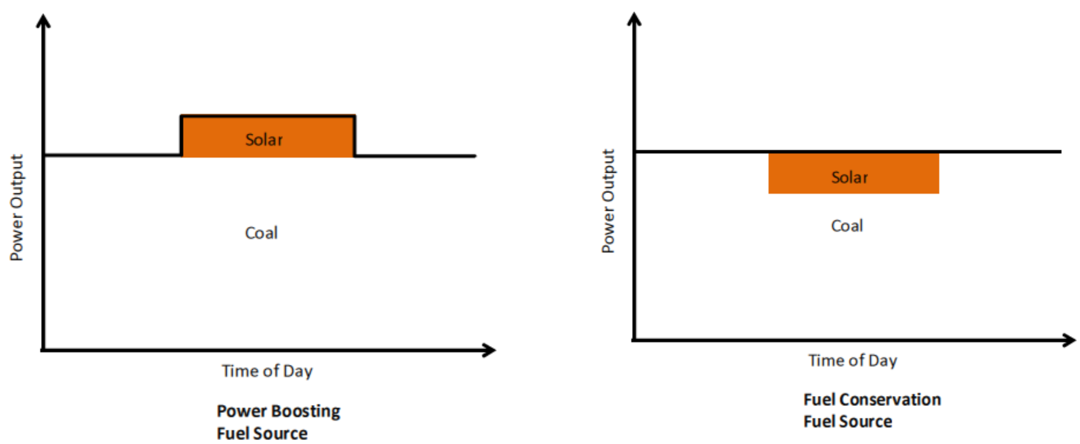
Solar aided power generation is capable of increasing generating capacity up to 20 percent theoretically if all feedwater heaters are replaced by solar energy during periods of peak demand while maintaining the same fuel consumption. (51) To determine the actual added benefit, a time fraction would need to be calculated because the availability of solar energy depends on seasons and locations.

A case study was conducted for a 200 MW plant with four low-pressure feedwater heaters, two high pressure feedwater heaters, and a deaerator evaluating supplemental solar feedwater heating. (51) The study assumed the SAFWH's liquid can be heated to 200 °C. The additional power generated in the steam turbine was calculated when each steam extraction is utilized in the turbine instead of being used for feedwater heating. It was determined that power output could be increased by 20 MW (10 percent) by replacing the highest stage of bled-off steam with solar aided feedwater heaters. Replacement of the next stage extraction provides an additional 4.5 MW. Replacement of the deaerator and four low-pressure extractions contributed subsequently less power output: 3.5 MW, 2.55 MW, 2.5 MW, 2.45 MW and 2.4 MW, respectively. is the study concluded that as long as the solar heat temperature is able, it is most efficient to replace the highest stage of bled-off steam in the cycle with solar heat. (51)

6.2 Power Boosting vs. Fuel Conservation

It has been observed that additional steam flow can be utilized for increasing power output in simulations. Another case study found in the literature search conducted a thermodynamic analysis of a replacement of all feedwater heaters with solar feedwater heaters for a 500 MW subcritical coal-fired plant. The analysis displayed a 76 MW increase in power output. However, the feasibility of generating excess power over the design rated capacity may be limited by constraints of the existing equipment and components. Therefore, it is more appropriate in most cases to evaluate the improvements in "fuel conservation mode." With the same solar feedwater heaters, the coal consumption can be reduced by 14 percent while maintaining the design rated capacity. (52) Exhibit 29 displays power boosting and fuel conservation modes of operation. It is shown that additional power output is possible during daylight hours. Conversely, it is also possible to maintain normal power output levels during daylight hours and reduce the amount of fuel consumed.

Exhibit 29 Power Boosting and Fuel Conservation Mode for Solar Assisted Feedwater Heating



6.3 Solar Irradiation and Solar Collection Fields

The National Solar Radiation Data Base has collected annual direct normal irradiance (DNI) levels since 1961. Thirty year averages have been publicized for over 230 sites in the United States. International data is also available from data collected over a similar time span. This analysis is based on hourly calculations for one day per year which is assumed to represent the annual performance.

The 90 MW plant case study found in the literature is located at a site with a DNI of 6.75 kWh/m^2. The plant requires a 160,000 m^2 solar collection field with 75 percent efficiency to completely replace the feedwater heating load for 11 hours/day. A relatively smaller solar field of 40,000 m^2 would only be able to supply heating to the low pressure heaters. Plant thermal efficiency peaks around the optimized solar field size of 90,000 m^2 when the solar heating is able to supply all of the feedwater heat for 5 hours/day. (50)

A 500 MW case study found in the literature was located at a site with a DNI of 6.0 kWh/m^2. The analysis of this unit concluded that replacement of one high pressure feedwater heater can supply 90 MW with a solar field size of 300,000 m^2 at 60 percent collector efficiency. This equates to an overall plant efficiency increase of 6.96 percent. Replacement of all feedwater heaters would increase plant efficiency by 16.4 percent. (52) The estimated solar field size for replacing all feedwater heaters is 710,000 m^2.

6.4 Technical Analysis

Exhibit 30 lists the baseline assumptions for this case study's two plants: Plant A is assumed to be located in Phoenix, Arizona and Plant B in Indianapolis, Indiana. The sites were chosen to evaluate the efficiency improvements based on available solar radiation. Each plant is assumed to be an existing 550 MW subcritical coal-fired plant with an added 350,000 m^2 parabolic trough solar collection field. The 113,000 kg/hr extraction steam supply for feedwater heating to the last stage, high pressure feedwater heater is being replaced by the solar thermal supply.

The parabolic trough-type solar collector uses curved mirrors to concentrate solar radiation onto a tube filled with fluid. The heated fluid, typically oil, is then transported to a heat exchanger to transfer the heat to the feedwater. Sixty percent efficiency for the parabolic trough field was used in this analysis, which appears to be a typical value based on a literature review, assuming no parasitic losses associated with the solar field. Average yearly DNI is based on east-west tracking for concentrating collectors from 30-year (1961-1990) averages of monthly solar radiation.

In an effort to keep the size of the solar field practical and plant control schemes simplistic, the replacement to solar feedwater heating was limited to one feedwater heater. The "power boosting" cases were not evaluated because conditions commonly exceeded the design rated capacity of the steam turbines and steam piping.

Exhibit 30 Solar Assisted Feedwater Heater Case Baseline Assumptions

Plant	Location	Net Output, MW	Normal Irradiance (DNI)[xvi], kWh/m^2	Solar Field Size, m^2	Post-Retrofit Heat Rate, Btu/kWh	Heat Rate Improvement, %
Plant A	Phoenix, AZ	550	5.20	350,000	9,820	7.0
Plant B	Indianapolis, IN	550	2.70	350,000	9,332	3.6

6.5 Financial Analysis

Unlike the previous efficiency studies, solar assisted feedwater heaters are a new concept to current coal-fired power plants. For these financial evaluations we will use six data points listed in the exhibit below.

[xvi] Solar radiation data manual for flat-plate and concentrating collectors

Exhibit 31 Solar Assisted Feedwater Heater Installation Cost

Capital Cost	$ (2012)	Reference
660 MW Supercritical plant with indirect solar aided feedwater heating	$103 Million	(52)
350 MW Supercritical plant with indirect solar aided feedwater heating	$34.78 Million	(53)
125 MW plant with seven (7) indirect solar aided feedwater heaters	$17.8 Million	(54)
750 MW plant with indirect solar aided feedwater heaters	$98.8 Million	(55)
498 MW plant with seven (7) indirect solar aided feedwater heaters	$15.0 Million	(56)
90 MW plant with SAFWH meant to add to 7.5 MW of power	$48 – 112 Million	(50)
90 MW plant with SAFWH meant to increase efficiency and decrease coal usage	$120 – 280 Million	(50)

Given the solar field size listed in the technical analysis, the capital cost range should be between $35 million and $100 million. This cost range will be applied to Plant A and B, to calculate the resulting cost of electricity impact. Exhibit 32 is a simplified payback period calculation showing the range of payback required, given the heat rate improvements listed in Exhibit 30. The payback period is defined as the length of time (in years) the unit needs to operate until the increase in capital expenditure is outweighed by the annual savings in fuel cost. The construction period is one year, including lost revenue during the down time (which equals the construction period). Additional cost breakdowns are listed in Appendix D.

Exhibit 32 Solar Assisted Feedwater Heater Payback Period

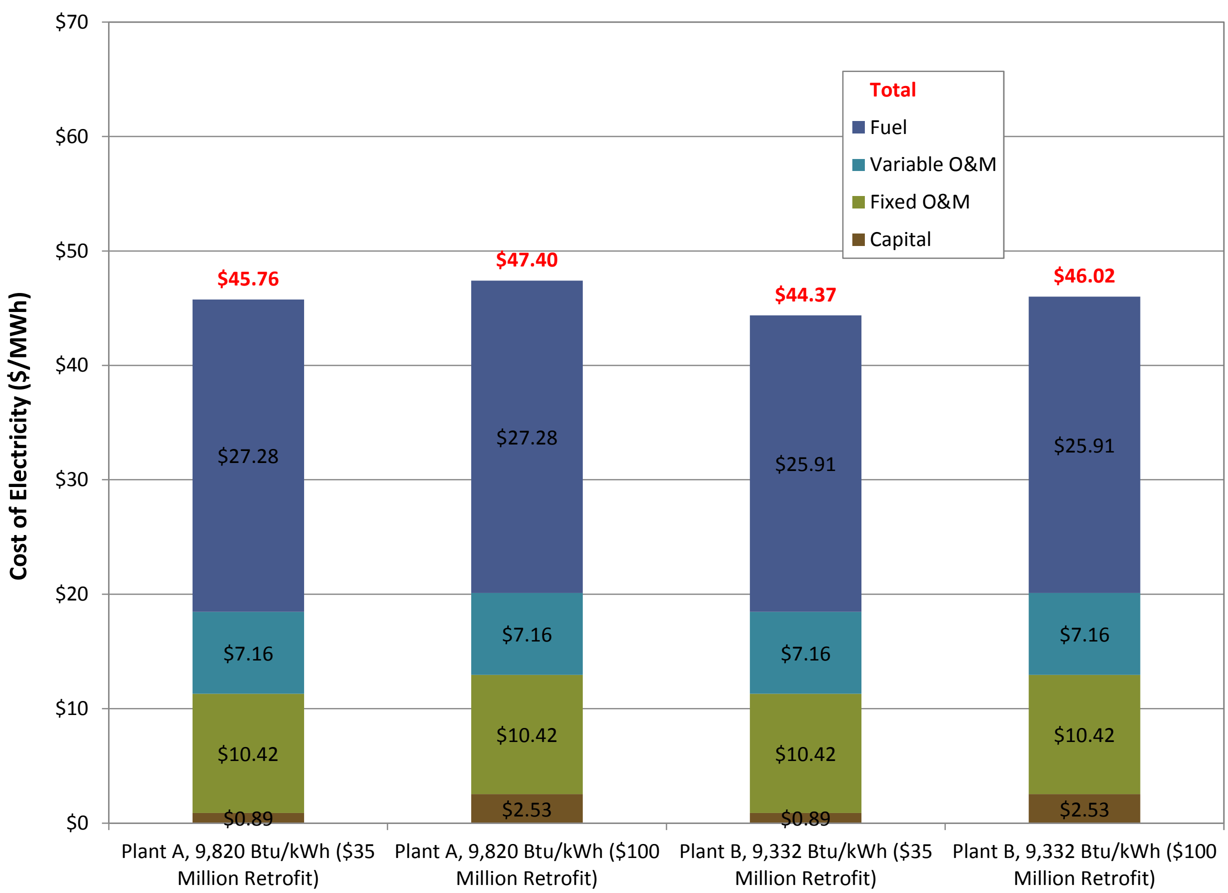
	Plant A			Plant B		
Heat Rate Improvement (Btu/kWh)	Base	739	739	Base	348	348
TOTAL (STEAM TURBINE) POWER, kWe	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**
Net Plant Efficiency (HHV)	32.32%	34.76%	34.76%	35.26%	36.57%	36.57%
Net Plant Heat Rate, Btu/kWh	10,559	9,820	9,820	9,680	9,332	9,332
As-Received Coal Feed, lb/hr	497,810	462,963	462,963	456,369	439,940	439,940
Total Fuel HHV Input, MMBtu/hr	5,807	5,401	5,401	5,324	5,132	5,132
Coal savings MMBtu/hr		406.52	406.52		191.66	191.66
Coal savings $/year		$7,905,774	$7,905,774		$3,727,361	$3,727,361
Capital Cost		$35,000,000	$100,000,000		$35,000,000	$100,000,000
Payback (years)		**4**	**13**		**9**	**27**

Assumptions:

1) 11,666 Btu/lb coal
2) 85% capacity factor
3) $2.61/MMBtu Coal price

Exhibit 33 shows the first-year COE for Plant A and B, given the heat rate improvements outlined in Exhibit 32 above.

Exhibit 33 Solar Assisted Feedwater Heater First-Year Cost Of Electricity



6.6 Conclusion

Existing coal plants with available land for a solar collection field can benefit from solar feedwater heating. Efficiencies can be improved during daylight hours year-round, and especially during the long summer daylight hours. The amount of solar irradiation available at locations will also impact the decision to invest in solar feedwater heating. Boosting plants' power output is possible, but limited by the design rated capacity of existing equipment and components. More appropriately, the plant can conserve fuel and lower emissions while maintaining normal power output.

Exhibit 34 lists the pre-and post-retrofit CO_2 emission summary for Plant A and Plant B.

Exhibit 34 Solar Assisted Feedwater Heater CO_2 Emission Reduction Summary

Plant	Heat Rate, Btu/kWh[xvii]	Pre-retrofit CO_2 Emissions Million tonne/yr[xviii]	Post-retrofit CO_2 Emissions Million tonne/yr[xviii]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A	9,820 (739 reduction)	3.93	3.65	0.28 (7.1%)
Plant B	9,332 (348 reduction)	3.60	3.47	0.13 (3.6%)

7 Combined Enhancements

The evaluation of the three "off the shelf" efficiency improvements were conducted independently with separate technical and financial analyses. It is recognized that combining the improvements may be advantageous for significant plant efficiency gains. This would also be in line with the thinking that if a utility is planning on taking a plant offline to perform upgrades that will lengthen its service life, it would make multiple upgrades while the plant is shut down.

This section looks at the cost, performance, and CO_2 emissions impacts of implementing all three "off the shelf" upgrades at both Plant A and B. It is understood that in reality, Plant A is likely to implement a different subset of upgrades than Plant B, as is illustrated by the reduced efficacy of upgrading the pulverizer on Plant B shown in Section 3. However, the decision was made to apply the retrofits equally for the sake of consistency.

[xvii] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "739 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 739 Btu/kWh and the power plant is more effiecient.

[xviii] Assumes annual capacity factor of 85%

7.1 Technical Analysis

The heat rate improvements of the steam turbine, condenser, and coal pulverizer cannot be simply added. Any calculation that ignores the interaction between the coal pulverizer and the boiler, with its effect on the steam turbine and condenser would be incorrect. For example, when extracting more energy out of the turbine, the condenser may not be as inefficient as assumed, and therefore the condenser efficiency cannot be increased as much as indicated in this study. The interaction between the steam turbine and condensers are intimately linked. This study does not attempt to calculate the effect of all these changes on one single unit, but instead recognizing there will be interplay between the units.

Therefore, based on engineering judgment, this paper assumes that the total efficiency gains are less than the sum of all its individual parts (they are not additive). This is accounted for in the analysis by using the greater of the two improvements between the steam turbine and condenser, and only 50 percent of the coal pulverizer improvements.

Since solar assisted feedwater heating is not widely practiced in the domestic power generation industry, it is still considered to be an immature technology, and is therefore not included along with the other efficiency improvements in the cumulative analysis.

Assuming each of the first three improvements: coal pulverizer, steam surface condenser, and steam turbine are combined for the Plant A configuration, and applying the factors discussed above, the following results occur:

Exhibit 35 Plant A Combined Efficiency Improvement Without Solar Assisted Feedwater Heating

Upgrade/Retrofit	Pre-Retrofit Heat Rate, Btu/kWh	Heat Rate Improvement Range, Btu/kWh	New Heat Rate, Btu/kWh	Improvement Range, %
Coal Pulverizer	10,559	250 – 300	10,259 – 10,309	2.4 – 2.8
Steam Surface Condenser	10,559	264 – 370	10,295 – 10,189	2.5 – 3.5
Steam Turbine	10,559	422 – 581	9,978 – 10,137	4.0 - 5.5
Total		**547 - 731**	**9,828 – 10,012**	**5.2 - 6.9**

Applying the same factors to the improvements for Plant B resulted in the following:

Exhibit 36 Plant B Combined Efficiency Improvement Without Solar Assisted Feedwater Heating

Upgrade/Retrofit	Pre-Retrofit Heat Rate, Btu/kWh	Heat Rate Improvement Range, Btu/kWh	New Heat Rate, Btu/kWh	Improvement Range, %
Coal Pulverizer	9,680	50 - 100	9,580 – 9,630	0.52 – 1.03
Steam Surface Condenser	9,680	97 – 194	9,583 – 9,486	1 – 2
Steam Turbine	9,680	145 - 290	9,340 – 9,535	1.5 - 3
Total		**170 - 340**	**9,340 – 9,510**	**1.8 - 3.5**

7.2 Financial Analysis

Unlike the performance improvements, the costs of each individual modification can be added together. The COE calculations assumed in this study consider a one-year down time for construction. In an outage situation, it is more likely the plant would try to accomplish all the retrofits in a single outage rather than spacing them out. Therefore, no discount on labor or freight should be taken since the study assumes all modifications are happening simultaneously.

Exhibit 37 – Total Cumulative Efficiency Capital Cost

	Equipment Cost, $ Million	Labor & Freight Cost, $ Million	Total Cost, $ Million	Total Cost, $/kW
Coal Pulverizer	15.69	2.77	18.46	33.56
Steam Surface Condenser	8.05	1.37	9.42	17.12
Steam Turbine	7.20	1.00	8.20	14.91
Total	**30.94**	**5.14**	**36.08**	**65.60**

The cost of implementing the three "off the shelf" technology improvements was roughly $36 million dollars, with half of that cost associated with upgrading the coal pulverizer. In the case of both plants, this equates to almost $66/kW of capital upgrades. The included labor costs may be slightly understated, as multiple projects of this magnitude occurring at the same time may require additional construction supervision or far-reaching craftsman, creating additional costs.

The payback period for the three cumulative efficiency improvement projects (pulverizer and condenser upgrade, and steam turbine improvement) is shown in Exhibit 38. As was the trend when each of the three improvements was presented individually, the greatest improvements (and therefore shortest payback period) comes from Plant A, which was less efficient to begin with. When the same improvements are implemented on a more efficient plant, the overall benefit is less, and the payback period is therefore longer. As alluded to at the beginning of this section, the payback times for Plant B are skewed by including the coal pulverizer in its manifest of upgrades, owing to the reduced efficiency improvement and high cost.

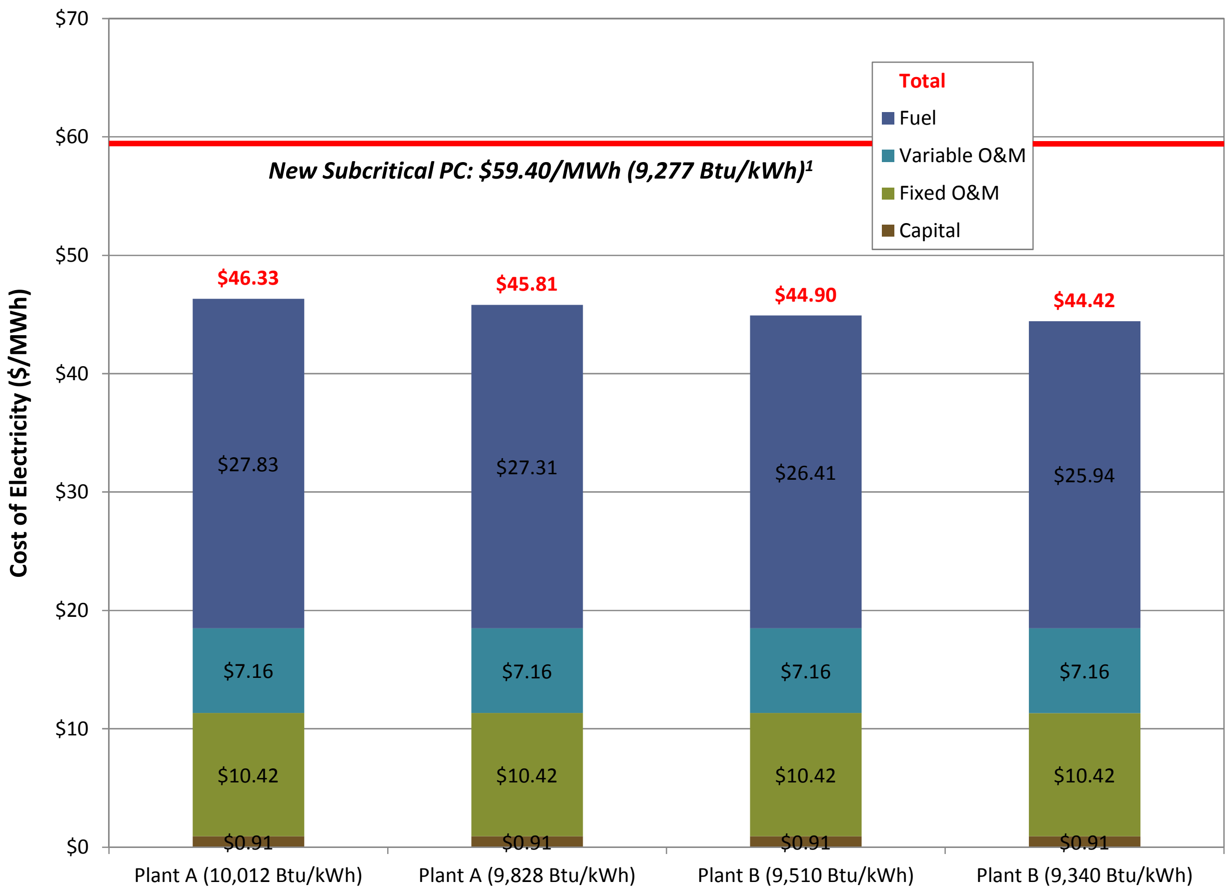
Exhibit 38 – Cumulative Efficiency Improvement Payback Period

	Plant A			Plant B		
Heat Rate Improvement (Btu/kWh)	**Base**	**547**	**731**	**Base**	**170**	**340**
TOTAL (STEAM TURBINE) POWER, kWe	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**	**550,000**
Net Plant Efficiency (HHV)	32.32%	34.09%	34.73%	35.26%	35.89%	36.54%
Net Plant Heat Rate, Btu/kWh	10,559	10,012	9,828	9,680	9,510	9,340
As-Received Coal Feed, lb/hr	497,810	472,021	463,346	456,369	448,354	440,339
Total Fuel HHV Input, MMBtu/hr	5,807	5,507	5,405	5,324	5,231	5,137
Coal savings MMBtu/hr		300.85	402.05		93.50	187.00
Coal savings $/year		$5,850,742	$7,818,816		$1,818,329	$3,636,658
Capital Cost		$36,080,000	$36,080,000		$36,080,000	$36,080,000
Payback (years)		**6**	**5**		**20**	**10**

Assumptions:

1) 11,666 Btu/lb coal
2) 85% capacity factor
3) $2.61/MMBtu Coal price

Exhibit 39 – Cumulative Efficiency Improvement First-Year Cost of Electricity



7.3 Conclusion

If a utility decides to make capital investments in an aging power plant, it is likely to make multiple investments to lengthen its service life and reduce the potential for forced outages in the future. This analysis shows that even with conservative assumptions regarding performance improvements – recognizing that not all improvements will be additive – plant efficiency can be enhanced and operating costs reduced.

As has been a theme of this study, older and less efficient plants typically have more to gain from capital upgrades, as they will recover costs quicker through reduced fuel costs. Even so, more contemporary and efficient plants can also benefit, although the selection of upgrades that make sense might be more limited.

The analysis of the cumulative retrofits found that at a capital expenditure of roughly $66/kW, the efficiency of plant A was improved up to 2.4 percentage points to 34.7% on a HHV basis. This efficiency gain could lead to a 6.9 percent reduction in CO_2 emissions and has a relatively attractive payback period of 5 or 6 years based on reduced fuel costs.

As expected, Plant B recognized a reduced, but still significant benefit, with efficiency improving 1.3 percentage points to 36.5%. This approaches the efficiency – and therefore emissions level – of a new subcritical PC plant, which is expected to operate at 36.8%. Longer payback times were reported for Plant B, but these results are somewhat skewed by the inclusion of the coal pulverizer upgrade. This upgrade doesn't necessarily make sense for Plant B owing to the reduced efficiency improvement and high cost. However, other upgrades may exist that would be applicable to Plant B and not Plant A which could further improve efficiency.

The cumulative CO_2 emission reduction summary is presented in Exhibit 40 below. These emission reductions are the result of improvements in the coal pulverizer and condenser, as well as the steam turbine upgrade to both Plant A and B. Lower and upper bounds emissions reductions are presented based on the potential range of efficiency impacts, which are certain to be plant specific.

Exhibit 40 Cumulative CO_2 Emission Reduction Summary

Plant	Heat Rate, Btu/kWh[xix]	Pre-retrofit CO_2 Emissions, Million tonne/yr[xx]	Post-retrofit CO_2 Emissions, Million tonne/yr[xx]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A – Lower Bound	10,012 (547 reduction)	3.93	3.73	0.20 (5.1%)
Plant A – Upper Bound	9,828 (731 reduction)	3.93	3.66	0.27 (6.9%)
Plant B – Lower Bound	9,510 (170 reduction)	3.60	3.54	0.06 (1.7%)
Plant B – Upper Bound	9,340 (340 reduction)	3.60	3.48	0.12 (3.5%)

8 Combined Enhancements Sensitivity Analysis

Section 7 examined the cumulative impacts of upgrading/improving three separate areas of the plant using "off the shelf" technology: the coal pulverizer, the condenser, and the steam turbine.

That analysis illustrated that significant efficiency improvements – and commensurate reductions in emissions and fuel costs – are possible, with older, less efficient plants having the greatest opportunity to recoup costs in a timely manor. One of the underlying assumptions in the analysis was that the efficiency upgrades are not additive. In other words, the efficiency improvements that results from doing each upgrade individually cannot be added together to arrive at the cumulative improvement that would result from doing all three upgrades together.

This assumption accounts for uncertainties involving how the performance of one piece of equipement might impact another. As explained above, when extracting more energy out of the turbine, the condenser may not be as inefficient as assumed, and therefore the condenser efficiency cannot be increased as much as indicated in Section 4. The interaction between the steam turbine and condensers are intimately linked. This interaction was accounted for in the base case (presented in Exhibit 39 and Exhibit 40) by only considering the larger of either the condenser or steam turbine upgrade, and half of the coal pulverizer improvement.

[xix] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "547 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 547 Btu/kWh and the power plant is more effiecient.

[xx] Assumes annual capacity factor of 85%

However, it is recognized that these intereactions are hard to quantify, and may vary on a plant to plant basis. For example, it is unknown to what degree the steam turbine upgrade may erode any potential heat rate improvement that results from also addressing the condenser, as described in Section 4.

The analysis performed in this section relaxes some of the conservative assumptions made in Section 7 to evaluate how a plant might perform if upgrades turned out to be more synergistic. For example, in Section 7 the conservative assumption was made that only the larger of the steam turbine or condenser heat rate improvement will be considered, along with half of the coal pulverizer improvement. Exhibit 41 shows the cost of electricity results when this conservative assumption is relaxed, and includes the entire steam turbine upgrade heat rate improvement, along with half of both the condenser and coal pulverizer improvements. The incremental CO_2 emission reductions (beyond the case case, presented in Exhibit 40) that result from a less conservative engineering assumption are shown in Exhibit 42. As shown, additional CO_2 reduction of up to 2 percent can be achieved by Plant A and up to 1.2 percent by Plant B.

Exhibit 41 – Cumulative First Year Cost of Electricity Sensitivity Summary

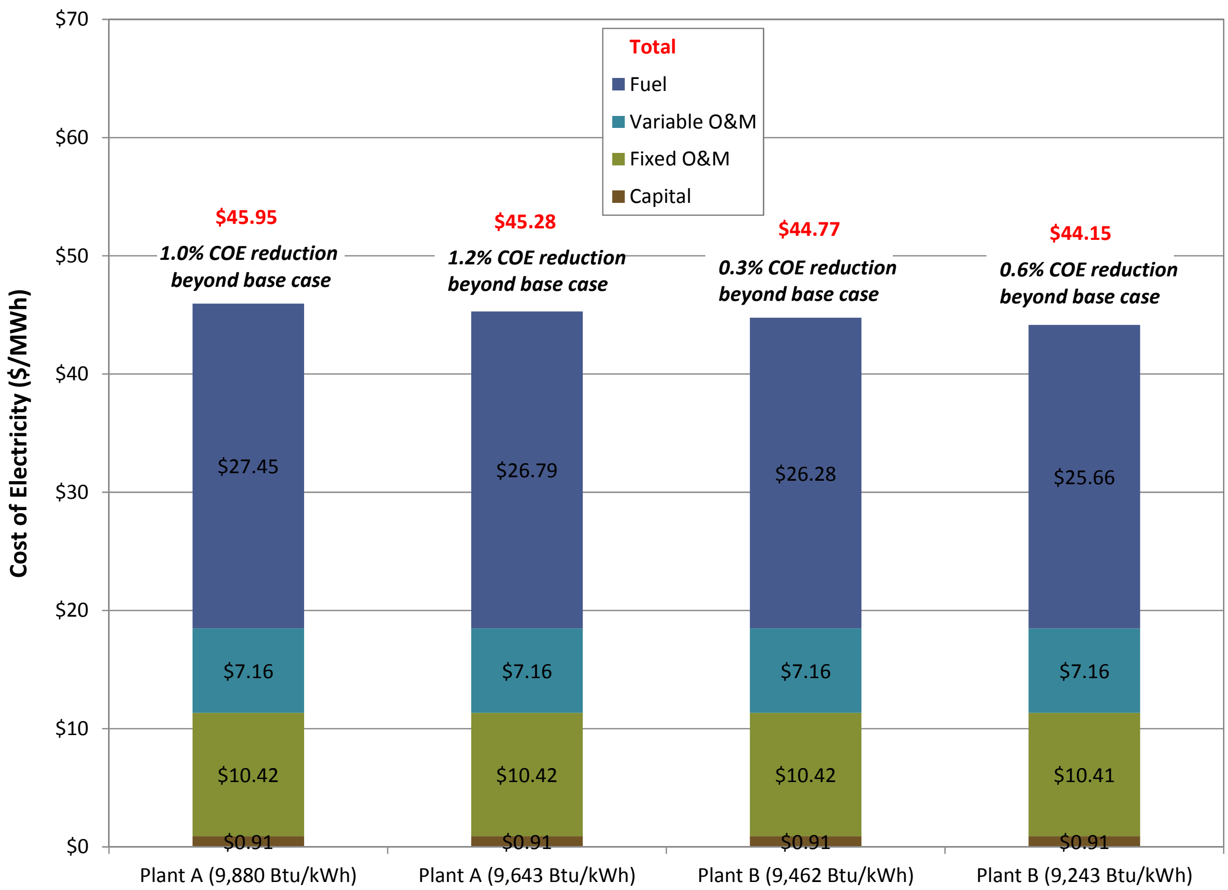


Exhibit 42 – Cumulative CO_2 Emission Reduction Sensitivity Summary

Plant	Heat Rate, Btu/kWh[xxi]	Pre-retrofit CO_2 Emissions, Million tonne/yr[xxii]	Post-retrofit CO_2 Emissions, Million tonne/yr[xxii]	Reduction in CO_2 Emissions, Million tonne/yr
Plant A – Lower Bound	9,880 (679 reduction)	3.93	3.68	0.25 (1.4% CO_2 emission reduction beyond base case)
Plant A – Upper Bound	9,643 (731 reduction)	3.93	3.59	0.34 (2.0% CO_2 emission reduction beyond base case)
Plant B – Lower Bound	9,462 (170 reduction)	3.60	3.52	0.08 (0.5% CO_2 emission reduction beyond base case)
Plant B – Upper Bound	9,243 (340 reduction)	3.60	3.44	0.16 (1.2% CO_2 emission reduction beyond base case)

Exhibit 43 summarizes the differences between the conservative and relaxed approaches. These results are based on the analysis of the cumulative retrofits with a capital expenditure of roughly $66/kW, as described in Section 7. These results show that by relaxing the conservative assumptions regarding the synergies of upgrading multiple areas of the plant, the efficiency of Plant A was improved up to 3.1 percentage points to 35.4% on a HHV basis. This efficiency gain could lead to a 8.7 percent reduction in CO_2 emissions and has a relatively attractive payback period of 4 or 5 years based on reduced fuel costs.

Plant B recognized a reduced, but still significant benefit, with efficiency improving 1.7 percentage points to 36.9%. This eclipses the efficiency – and therefore emissions level – of a new subcritical PC plant, which is expected to operate at 36.8%, likely due to the inclusion of state-of-the-art equipment not necessarily yet included in the NETL Bituminous Baseline Report. Payback times were reduced to 8 to 16 years for Plant B by this efficiency boost, but again, these results are somewhat skewed by the inclusion of the coal pulverizer upgrade. Omitting the coal pulverizer upgrade would reduce payback times to 5 to 8 years.

[xxi] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a "679 Btu/kWh reduction" in heat rate means the heat rate has dropped – i.e. improved – by 679 Btu/kWh and the power plant is more effiecient.

[xxii] Assumes annual capacity factor of 85%

Exhibit 43 – Cumulative Impacts Results Comparison

Plant	Heat Rate, Btu/kWh[xxiii]	Efficiency, HHV	Reduction in CO_2 Emissions from Pre-Retrofit, %
Plant A – Conservative	9,880 (679 reduction)	34.7%	6.9%
Plant A – Relaxed Requirements	9,643 (731 reduction)	35.4%	8.7%
Plant B – Conservative	9,462 (170 reduction)	36.5%	3.5%
Plant B – Relaxed Requirements	9,243 (340 reduction)	36.9%	4.4%
New Subcritical PC	9,277 (n/a)	36.8%	

9 Conclusion

This study has evaluated the impact of retrofitting or upgrading two hypothetical power plants that are representative of coal-fired power generation units in the existing fleet.

Four retrofit opportunities were examined individually, then a second analysis was performed in order to assess the cumulative impact of retrofitting multiple areas of the plant at once. This latter analysis was limited to the three technologies which are currently available “off the shelf” in order to evaluate the near term opportunites for utilities and to inform policy makers.

The fourth technology – solar feedwater heaters – is considered to be an area of further interest for research by will require additional demonstration before it is ready for wide-scale deployment.

The following metrics were reported for each scenario: (1) efficiency benefits, (2) CO_2 emissions reductions over the un-retrofitted plant, and (3) payback time. The latter was reported based on a simplified calculation that compared the annual fuel cost savings to the capital cost of the plant. While it is understood the latter metric is highly sensitive to how often the plant dispatches (i.e.

[xxiii] Heat Rates are inversely proportional to efficiency, so that a lower heat rate connotes a more efficient power plant. Hence a “679 Btu/kWh reduction” in heat rate means the heat rate has dropped – i.e. improved – by 739 Btu/kWh and the power plant is more effiecient.

it's capacity factor), it is assumed that upgrades are being performed so that these plants can serve as baseload generation.

Broadly, it was found that:

- Older, less efficient plants – such as Plant A – stand to benefit more from technology upgrades. Payback ranged from one to seven years depending on the level of efficiency achieved.
- For newer plants – such as Plant B – certain retrofits might not be economically viable based on a limited efficiency improvement at a high capital cost. Upgrading the coal pulverizer, was one example of this.
- In general, significant efficiency improvements can be achieved, with newer plants being able to achieve the performance of a new subcritical power plant and older plants achieving 2 or 3 percentage point increases in efficiency when multiple retrofits are undertaken.
- Significant emissions reductions are possible, ranging from one percent for retrofits such as coal pulverizer upgrades on newer plants to almost nine percent for older plants when cumulative retrofits are applied in synergistic ways.
- The steam turbine upgrade provided the most impact (efficiency improvement) at the lowest cost ($15/kW), while the condenser retrofit was a similar cost ($17/kW) with slightly less of a performance impact. The coal pulverizer and ancillary equipment had the highest cost and the lowest performance impact.
- Solar feedwater heaters hold some promise for significant reductions in efficiency but require additional development and demonstration.

This work would seem to validate previous analyses by NETL which pointed to the potential for emissions reductions in the existing fleet. Furthermore, only three technologies were evaluated, and numerous others – ranging from advanced sensors to new burners – also exist and have the potential for greater emissions reductions. This points to a path forward for emissions reductions from the existing coal fleet, some of which will be economically attractive over short payback times.

It should be cautioned, however, that not every plant will be amenable to upgrades, as shown by the reduced impact of upgrades to Plant B, both in general, and with regard to specific technologies. Some plants may not be amenable at all due to constraints such as lack of physical space to install new equipment or inability to schedule sufficient downtime.

Lastly, while the potential may exist to improve the efficiency at certain facilities, barriers to deployment also exist. The most notable of these is the New Source Review (NSR) rule, the existance of which is often cited as a rationale for not updating a plant. Overcoming this barrier and finding a path forward for the existing fleet to reduce emissions would seem to be a laudable goal for regulators and lawmakers.

10 Future Work

As noted above, this study examined only three of many "off the shelf" technologies which can be used to improve the performance of coal-fired power plants. Furthermore, these technologies were applied to representative, albeit hypothetical, power plants. Future work is likely to focus on improving the veracity of cost estimates and expanding the work to evaluate other technologies, both "off the shelf" and "potential" (such as the solar feedwater heaters). There is also a desire – funding permitting – to work with utilities and stakeholders to see how improvements can be made to real world assets.

References

1. **Krulla, K and DiPietro, P.** *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions.* 2010.

2. **Brindle, Ross and Eisenhauer, Jack.** *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States.* 2010.

3. **Eisenhauer, Jack and Scheer, Richard.** *Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants.* 2009.

4. **National Energy Technology Laboratory.** *Cost and Performance Baseline for Fossil Energy Plants; Volume 1: Bituminous Coal and Natural Gas to Electricity.* s.l. : NETL, November 2010. DOE/NETL-2010/1397.

5. **Storm, Dick.** Pulverizers 101: Part II. *CoalPower.* [Online] October 1, 2011. [Cited: February 21, 2013.] http://www.coalpowermag.com/plant_design/349.html.

6. **Vierstra, Scott.** Improved Coal Fineness Improves Performance, Reduces Emissions. *Coal Power.* [Online] October 1, 2011. [Cited: February 13, 2013.] http://www.coalpowermag.com/plant_design/Improved-Coal-Fineness-Improves-Performance-Reduces-Emissions_350.html.

7. **Storm, Dick.** *Efficiency Improvements to the Existing Coal-Fired Fleet.* s.l. : American Coal Council / STI, 2011.

8. **Environmental Protection Agency.** *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers.* s.l. : Office of Air and Radiation, 2010.

9. *A Case Study of How Vertical Spindle Pulverizer Performance is Related to Overall Plant Performance.* **Storm, Steve.** Atlanta, Georgia : ASME Electrical Power Conference, 2006.

10. *ATRITA Pulverizer System Upgrade for PRB Coal Conversion.* **Stodden, Steve.** Clearwater, FL : BabcockPower / Clearwater Coal Conference, 2006.

11. *Coal Mill and Combustion Optimization on a Once-through, Supercritical Boiler with Multivariable Predictive Control.* **Barnoski, Steve.** Nashville, TN : 48th Annual ISA POWID Symposium, 2005.

12. **Storm, Dick.** Pulverizers 101: Part 1. *Coal Power.* [Online] August 1, 2011. [Cited: February 20, 2013.] http://www.coalpowermag.com/ops_and_maintenance/Pulverizers-101-Part-I_329.html.

13. **Alstom.** *MPS-type Pulverizer Products and Services.* s.l. : Alstom, 2008.

14. **Babcock & Wilcox Power Generation Group.** *B&W Roll Wheel Pulverizers.* s.l. : Babcock & Wilcox Power Generation Group Inc, 2002.

15. *Improvement Power Plant Efficiency with Condenser Pressure.* **Cosough, Amir.** 3, s.l. : International Journal of Multidisciplinary Sciences and Engineering, June 2011, Vol. 2.

16. **IFFCO.** *Improve Steam Turbine Efficiency.* July 2, 2010.

17. Proven Solutions to Common Condenser Problems. *INTEK.* [Online] [Cited: April 17, 2013.] http://www.intekflow.com/technical-services/power-plant-condenser-experts/default.html.

18. **INTEK.** Recovering Performance Loss Due to Air Binding. *A Case Study.* Westerville, OH : INTEK, Inc., 2011.

19. **Krysicki, J.** *Improve Plant Performance and Reduce CO2 Emission Through State-of-the-Art Condenser Cleaning and Air In-leakage Detection.* s.l. : Conco Systems, Inc.

20. **GMA.** Coating vs. Retubing in Used Steam. *Services.* [Online] [Cited: March 27, 2013.] http://www.gma-tech.com/index.php?mod=servizi&C=22&page=coating_vs._retubing_in_used_steam&lang=UK.

21. *Plant Performance Improvement Through the Use of Innovative Condenser Cleaning Technology and Leak Detection Inspection.* **Arvay, Michael.** New Delhi, India : Conco, Power Plant Summit 2008, 2008.

22. *Condenser Performance Improvement Through Innovative Cleaning and Leak Detection Technology.* **Fayard, Eric F.** s.l. : Coal Power , April 1, 2011, Vol. Conco Systems Inc.

23. **Cooling Quality Management.** *ATCS - Automatic Tube Cleaning System; Product Description.* s.l. : CQM.

24. **INTEK.** Condenser Performance Optimization and Life Extension, A Case Study. s.l. : INTEK, Inc., 2008.

25. *More productivity pays off for northeast power plant.* **INTEK.** s.l. : Energy-Tech, April 2006.

26. **Boudreaux, Kevin.** *Improve Condenser Performance Through Better Instrumentation.* s.l. : Nalco. Co., June 1, 2012.

27. **Bellman, David.** *Electric Generation Efficiency.* s.l. : National Petroleum Council, 2007.

28. **Sargent & Lundy.** *Coal-Fired Power Plant Heat Rate Reductions.* January 22, 2009. SL-009597.

29. **Burnes, John M.** *Modular Steam Condenser Replacements Using Corrosion Resistant High Performance Stainless Steel Tubing.* s.l. : Burns Engineering Service, Inc.

30. **NEI Corporation.** Superhydrophobic Coating. *NEI Corporation.* [Online] [Cited: April 17, 2013.] http://neicorporation.com/products/coatings/superhydrophobic-coating/.

31. **Power Engineering.** Condenser Experts Suggest Improvements In Performance and Design. *Power Engineering.* [Online] June 1, 2005. [Cited: April 17, 2013.] http://www.power-eng.com/articles/print/volume-109/issue-6/news-update/condenser-experts-suggest-improvements-in-performance-and-design.html.

32. **Janikowski, Daniel.** Condenser Tube Life-Cycle Economics. *Coal Power.* [Online] Coal Power Magazine, October 08, 2009. [Cited: April 17, 2013.] http://www.coalpowermag.com/ops_and_maintenance/Condenser-Tube-Life-Cycle-Economics_219.html.

33. **Panarese, John.** Ball Park Pricing for Taprogee Ball-Tube Cleaning System. *Email.* April 19, 2013.

34. *Enhanced Condensation on Lubricant-Impregnated Nanotextured Surfaces.* **Anand, Sushant.** 11, Massachusetts : American Chemical Society, 2012, Vol. 6.

35. **Curran, Ed.** Case Studies - Condenser Tube ID Coating. *Curran International.* [Online] August 3 and 4, 2011. [Cited: April 10, 2013.] http://www.curranintl.com/case_studies/EPRI_Condenser_Technology_Seminar.asp.

36. **Leyzerovich, A.** *Steam Turbines for Modern Fossil-Fuel Plants.* 2008.

37. *Design Features and Performance Details of Brush Seals for Turbine Applications.* **Neff, M.** s.l. : GT2006, ASME Turbo Exp 2006, May 2006.

38. **Mechanical Dynamics & Analysis, Ltd.** *Steam Turbine Retrofits.* 2008.

39. —. *Turbo Parts Advanced Seal System.* 2011.

40. **Smiarowski, M.** *Steam Turbine Modernization Solutions Provide A Wide Spectrum of Options to Improve Performance.* s.l. : Siemens Power Generation, 2005.

41. **Lesiuk, J. F.** *Steam Turbine Uprates.* s.l. : GE Power Systems, October 2000.

42. *The Value of Steam Turbine Upgrades.* **Potter, K.** s.l. : Power Engineering, November 1, 2005.

43. **Folsom, B.** *Combustion Modification - An Economic Alternative for Boiler NOx Control.* s.l. : GE Power Systems, April 2001.

44. **Cheski, Jeffery R.** *A Large Steam Turbine Design and Operation History.* s.l. : Siemens Turbine Engineering, September 23, 2005.

45. **United States Department of Energy.** Improving Steam System Performance. *Industrial Technologies Program.* October 2007.

46. **Dooley, B.** *Investigation of Electrophysical Effects in the Turbine Exhaust Upon Steam Flow and Power Output.* s.l. : EPRI, September 1999.

47. *Steam Turbine upgrading low-hanging fruit.* **Peltier, Robert.** 3, s.l. : Power Magazine, April 2006, Vol. 150.

48. *Maintenance and Overhaul of Steam Turbines.* **Latcovich, John.** Moscow : International Association of Engineering Insurers 38th Annual Conference, 2005. IMIA-WPG 42 (05).

49. **TurboSteam.** *Proposal for the Supply of One Back-Pressure Steam turbine Generator set; Proposal to Wausau-Mosinee Papermill Company.* June 2001.

50. *Assessment of Solar-Coal Hybrid Electricity Power Generating Systems.* **Oladiran, Moses T, Kiravu, Cheddi and Plumb, Ovid A.** 1, s.l. : David Publishing, 2012, Vol. 6.

51. **Hu, Eric, Yang, Yongping and Nishimura, Akira.** Solar Aided Power Generation: Generating "Green" Power from Conventional Fossil Fuelled Power Stations. [book auth.] Dr. Mohammad Rasul. *Thermal Power Plants.* s.l. : InTech, 2012.

52. *4-E (Energy, Exergy, Environment, and Economic) analysis of solar thermal aided coal-fired power plants.* **Suresh, M.V.J.J., Reddy, K.S. and Kolar, A.K.** 4, s.l. : Energy for Sustainable Development, 2010, Vol. 14.

53. *Proposed Partial Repowering of a Coal-Fired Power Plant Using Low-Grade Solar Thermal Energy.* **Hong, Hui.** s.l. : International Journal of Thermodynamics, 2011, Vol. 14.

54. *Solar-Coal Hybrid Thermal Power Generation - an Efficient Way to Use Solar Energy in China.* **Hou, Hongjuan.** 4, s.l. : International Journal of Energy Engineering, 2012, Vol. 2.

55. **CS ENergy.** Kogan Creek Soalr Booster Project. 2012.

56. **Hu, Eric.** *Solar Power Boosting of Fossil Fuelled Power Plants.* s.l. : University of New South Wales.

57. **Ciferno, J.** DOE/NETL Existing Plants CO2 Capture R&D Program. s.l. : 2020 Carbon Capture Workshop, October 5-6, 2009.

58. *Assessing New Product Development Practices and Performance: Establishing Crucial Norms.* **Page, A.L.** 1993, Journal of Product Innovation Management, pp. 201-215.

59. **NETL.** Technologies: Carbon Sequestration. *NETL Web Site.* [Online] 2010. [Cited: May 8, 2010.] http://www.netl.doe.gov/technologies/carbon_seq/index.html.

60. **Pall Power Generation.** *Improving Coal Pulverizer Performance and Reliability.* Port Washington, NY : s.n., 2007.

61. *Heat Rate and Combustion Performance Improvement by Applying the Storm Performance Preservation Program.* **Storm, Dick.** Albemarle, NC : Storm Technologies Inc, 2005, Vol. 8.

62. *Finding, fixing problems in coal pulverizer exhauster bearings.* **Miska, Brian.** s.l. : Reliable Plant, 2007.

63. **Kubik, W. J.** *Improved Steam Condenser Gas Removal System.* Batavia, NY : Graham Manufacturing Company.

64. *Retrofit Decreases Dissolved Oxygen at Low Loads.* **Laughlin, James.** s.l. : Power Engineering, 3/1/2007.

65. **CONCO.** Improving Condenser Efficiency with Innovative Scale Cutting Technology. *CONCO.* [Online] [Cited: April 17, 2013.] http://www.concosystems.com/node/54.

66. **Siemens AG.** *Condenser Upgrades.* s.l. : Siemens AG, 2008.

Appendix A Detailed COE Calculations for Pulverizer

Case	Plant A	Plant A-300	Plant B	Plant B-100
Case Description	1968 Ball Mill, 10559 heat rate	New Pulverizer 10259 heat rate	1995 MPS 89, 9680 heat rate	New Pulverizer 9580 heat rate
Capacity Factor	0.85	0.85	0.85	0.85
Total Plant Retrofit Cost, 1000$	$0	$18,460	$0	$18,460
Fuel Consumption, MMBtu/day	139,379	135,419	127,776	126,456
First Year Fuel Cost, $	$132,779,214	$129,006,720	$121,725,806	$120,468,308
First Year Fixed O&M Cost, $	$40,090,350	$40,090,350	$40,090,350	$40,090,350
First Year Variable O&M Cost, $	$32,416,863	$32,416,863	$32,416,863	$32,416,863
Gross Plant Output, kW	550,000	550,000	550,000	550,000
Net Plant Output, kW	516,130	516,340	516,730	516,800
Annual Net kWh (100%)	4,521,298,800	4,523,138,400	4,526,554,800	4,527,168,000
1st year COE, mills/kWh (or $/MWh) [No TS&M]	46.97	46.58	44.47	44.19
LCOE, mills/kWh (or $/MWh) [No TS&M]	59.54	59.05	56.37	56.01
TPC, $/kW	0	71	0	71
1st year COE ($/MWh), capital	0.00	0.47	0.00	0.47
1st year COE ($/MWh), fixed	10.43	10.43	10.42	10.42
1st year COE ($/MWh), variable	7.17	7.17	7.16	7.16
1st year COE ($/MWh), fuel	29.37	28.52	26.89	26.61
1st year COE ($/MWh), total	**46.97**	**46.58**	**44.47**	**44.66**
LCOE ($/MWh), capital	0.00	0.59	0.00	0.59
LCOE ($/MWh), fixed	13.22	13.22	13.21	13.21
LCOE ($/MWh), variable	9.09	9.08	9.08	9.08
LCOE ($/MWh), fuel	37.23	36.15	34.09	33.73
LCOE ($/MWh), total	**59.54**	**59.05**	**56.37**	**56.61**
COE ($/MWh), 1st year	**46.97**	**46.58**	**44.47**	**44.66**
Capital/Total COE ($/MWh)	0.00%	1.00%	0.00%	1.05%
Fuel/Total COE ($/MWh)	62.53%	61.23%	60.47%	59.59%
Capital/Total LCOE ($/MWh)	0.00%	1.00%	0.00%	1.05%
Fuel/Total LCOE ($/MWh)	62.53%	61.23%	60.47%	59.59%

Appendix B Detailed COE Calculations for Condenser

Case	Plant A (Pre-Retrofit)	Plant A-370 (Post Retrofit)	Plant B (Pre-Retrofit)	Plant B-194 (Post Retrofit)
Case Description	Cooper Tube, 10559 heat rate	Titanium Tube 10189 heat rate	SS Tube, 9680 heat rate	Titanium Tube 9486 heat rate
Capacity Factor	0.85	0.85	0.85	0.85
Total Plant Retrofit Cost, 1000$	$0	$9,418	$0	$9,418
Fuel Consumption, MMBtu/day	139,379	134,495	127,776	125,215
First Year Fuel Cost, $	$132,779,214	$128,126,471	$121,725,806	$119,286,260
First Year Fixed O&M Cost, $	$40,090,350	$40,090,350	$40,090,350	$40,090,350
First Year Variable O&M Cost, $	$32,416,863	$32,416,863	$32,416,863	$32,416,863
Gross Plant Output, kW	550,000	550,000	550,000	550,000
Net Plant Output, kW	516,130	516,390	516,730	516,870
Annual Net kWh (100%)	4,521,298,800	4,523,576,400	4,526,554,800	4,527,781,200
1st year COE, mills/kWh (or $/MWh) [No TS&M]	46.97	46.16	44.47	43.92
LCOE, mills/kWh (or $/MWh) [No TS&M]	59.54	58.51	56.37	55.68
TPC, $/kW	0	36	0	36
1st year COE ($/MWh), capital	0.00	0.24	0.00	0.24
1st year COE ($/MWh), fixed	10.43	10.43	10.42	10.42
1st year COE ($/MWh), variable	7.17	7.17	7.16	7.16
1st year COE ($/MWh), fuel	29.37	28.32	26.89	26.35
1st year COE ($/MWh), total	**46.97**	**46.16**	**44.47**	**44.16**
LCOE ($/MWh), capital	0.00	0.30	0.00	0.30
LCOE ($/MWh), fixed	13.22	13.22	13.21	13.20
LCOE ($/MWh), variable	9.09	9.08	9.08	9.08
LCOE ($/MWh), fuel	37.23	35.90	34.09	33.40
LCOE ($/MWh), total	**59.54**	**58.51**	**56.37**	**55.98**
COE ($/MWh), 1st year	**46.97**	**46.16**	**44.47**	**44.16**
Capital/Total COE ($/MWh)	0.00%	0.52%	0.00%	0.54%
Fuel/Total COE ($/MWh)	62.53%	61.37%	60.47%	59.66%
Capital/Total LCOE ($/MWh)	0.00%	0.52%	0.00%	0.54%
Fuel/Total LCOE ($/MWh)	62.53%	61.37%	60.47%	59.66%

Appendix C Detailed COE Calculations for Steam Turbine

Case	Plant A (Pre-Retrofit)	Plant A (Post Retrofit)	Plant B (Pre-Retrofit)	Plant B (Post Retrofit)
Case Description	Free Vortex 10559 heat rate	Dense Pack 9820 heat rate	2nd Gen Vortex 9680 heat rate	Dense Pack 9293 heat rate
Capacity Factor	0.85	0.85	0.85	0.85
Total Plant Retrofit Cost, 1000$	$0	$8,200	$0	$8,200
Fuel Consumption, MMBtu/day	139,379	129,624	127,776	122,668
First Year Fuel Cost, $	$132,779,214	$123,486,304	$121,725,806	$116,859,289
First Year Fixed O&M Cost, $	$40,090,350	$40,090,350	$40,090,350	$40,090,350
First Year Variable O&M Cost, $	$32,416,863	$32,416,863	$32,416,863	$32,416,863
Gross Plant Output, kW	550,000	550,000	550,000	550,000
Net Plant Output, kW	516,130	516,640	516,730	516,990
Annual Net kWh (100%)	4,521,298,800	4,525,766,400	4,526,554,800	4,528,832,400
1st year COE, mills/kWh (or $/MWh) [No TS&M]	46.97	45.08	44.47	43.38
LCOE, mills/kWh (or $/MWh) [No TS&M]	59.54	57.14	56.37	54.98
TPC, $/kW	0	32	0	32
1st year COE ($/MWh), capital	0.00	0.21	0.00	0.21
1st year COE ($/MWh), fixed	10.43	10.42	10.42	10.41
1st year COE ($/MWh), variable	7.17	7.16	7.16	7.16
1st year COE ($/MWh), fuel	29.37	27.29	26.89	25.80
1st year COE ($/MWh), total	**46.97**	**45.08**	**44.47**	**43.58**
LCOE ($/MWh), capital	0.00	0.26	0.00	0.26
LCOE ($/MWh), fixed	13.22	13.21	13.21	13.20
LCOE ($/MWh), variable	9.09	9.08	9.08	9.07
LCOE ($/MWh), fuel	37.23	34.59	34.09	32.71
LCOE ($/MWh), total	**59.54**	**57.14**	**56.37**	**55.25**
COE ($/MWh), 1st year	**46.97**	**45.08**	**44.47**	**43.58**
Capital/Total COE ($/MWh)	0.00%	0.46%	0.00%	0.48%
Fuel/Total COE ($/MWh)	62.53%	60.53%	60.47%	59.21%
Capital/Total LCOE ($/MWh)	0.00%	0.46%	0.00%	0.48%
Fuel/Total LCOE ($/MWh)	62.53%	60.53%	60.47%	59.21%

Appendix D Detailed COE Calculations for SAFWH

Case	Plant A ($35M)	Plant A ($100M)	Plant B ($35M)	Plant B ($100M)
Case Description	$35 Million Retro	$100 Million Retro	$35 Million Retro	$100 Million Retro
Capacity Factor	0.85	0.85	0.85	0.85
Total Plant Retrofit Cost, 1000$	$35,000	$100,000	$35,000	$100,000
Fuel Consumption, MMBtu/day	118,832	118,832	123,176	123,176
First Year Fuel Cost, $	$113,205,000	$113,205,000	$117,343,677	$117,343,677
First Year Fixed O&M Cost, $	$40,090,350	$40,090,350	$40,090,350	$40,090,350
First Year Variable O&M Cost, $	$32,416,863	$32,416,863	$32,416,863	$32,416,863
Gross Plant Output, kW	550,000	550,000	550,000	550,000
Net Plant Output, kW	517,190	517,190	516,960	516,960
Annual Net kWh (100%)	4,530,584,400	4,530,584,400	4,528,569,600	4,528,569,600
1st year COE, mills/kWh (or $/MWh) [No TS&M]	43.44	45.08	43.49	43.49
LCOE, mills/kWh (or $/MWh) [No TS&M]	55.06	57.15	55.12	55.12
TPC, $/kW	135	387	135	387
1st year COE ($/MWh), capital	0.89	2.53	0.89	2.53
1st year COE ($/MWh), fixed	10.41	10.41	10.42	10.42
1st year COE ($/MWh), variable	7.16	7.16	7.16	7.16
1st year COE ($/MWh), fuel	24.99	24.99	25.91	25.91
1st year COE ($/MWh), total	**43.44**	**45.08**	**44.37**	**46.02**
LCOE ($/MWh), capital	1.12	3.21	1.12	3.21
LCOE ($/MWh), fixed	13.20	13.20	13.20	13.20
LCOE ($/MWh), variable	9.07	9.07	9.07	9.07
LCOE ($/MWh), fuel	31.67	31.67	32.85	32.85
LCOE ($/MWh), total	**55.06**	**57.15**	**56.24**	**58.33**
COE ($/MWh), 1st year	**43.44**	**45.08**	**44.37**	**46.02**
Capital/Total COE ($/MWh)	2.04%	5.61%	2.00%	5.50%
Fuel/Total COE ($/MWh)	57.52%	55.43%	58.40%	56.31%
Capital/Total LCOE ($/MWh)	2.04%	5.61%	2.00%	5.50%
Fuel/Total LCOE ($/MWh)	57.52%	55.43%	58.40%	56.31%

Appendix E Detailed COE Calculations for TOTAL Analysis

Case	**Plant A (10,012 Btu/kWh)**	**Plant A (9,828 Btu/kWh)**	**Plant B (9,510 Btu/kWh)**	**Plant B (9,340 Btu/kWh)**
Case Description	547 Btu/kWh improvement	731 Btu/kWh improvement	170 Btu/kWh improvement	340 Btu/kWh improvement
Capacity Factor	0.85	0.85	0.85	0.85
Total Plant Retrofit Cost, 1000$	$36,080	$36,080	$36,080	$36,080
Fuel Consumption, MMBtu/day	132,158	129,730	125,532	123,288
First Year Fuel Cost, $	$125,900,700	$123,586,903	$119,588,060	$117,450,313
First Year Fixed O&M Cost, $	$40,090,350	$40,090,350	$40,090,350	$40,090,350
First Year Variable O&M Cost, $	$32,416,863	$32,416,863	$32,416,863	$32,416,863
Gross Plant Output, kW	550,000	550,000	550,000	550,000
Net Plant Output, kW	516,500	516,630	516,860	516,950
Annual Net kWh (100%)	4,524,540,000	4,525,678,800	4,527,693,600	4,528,482,000
1st year COE, mills/kWh (or $/MWh) [No TS&M]	46.33	45.81	43.99	43.51
LCOE, mills/kWh (or $/MWh) [No TS&M]	58.73	58.06	55.76	55.15
TPC, $/kW	140	140	140	140
1st year COE ($/MWh), capital	0.91	0.91	0.91	0.91
1st year COE ($/MWh), fixed	10.42	10.42	10.42	10.42
1st year COE ($/MWh), variable	7.16	7.16	7.16	7.16
1st year COE ($/MWh), fuel	27.83	27.31	26.41	25.94
1st year COE ($/MWh), total	**46.33**	**45.81**	**44.90**	**44.42**
LCOE ($/MWh), capital	1.16	1.16	1.16	1.16
LCOE ($/MWh), fixed	13.21	13.21	13.20	13.20
LCOE ($/MWh), variable	9.08	9.08	9.08	9.07
LCOE ($/MWh), fuel	35.27	34.62	33.48	32.88
LCOE ($/MWh), total	**58.73**	**58.06**	**56.92**	**56.31**
COE ($/MWh), 1st year	**46.33**	**45.81**	**44.90**	**44.42**
Capital/Total COE ($/MWh)	1.97%	1.99%	2.03%	2.05%
Fuel/Total COE ($/MWh)	60.06%	59.62%	58.82%	58.38%
Capital/Total LCOE ($/MWh)	1.97%	1.99%	2.03%	2.05%
Fuel/Total LCOE ($/MWh)	60.06%	59.62%	58.82%	58.38%