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Environmental and Sustainable Technology Evaluation - Biomass Co-firing in Industrial Boilers – University of Iowa

Prepared by:

Southern Research Institute
Under Subcontract to ERG

For

U.S. Environmental Protection Agency

Office of Research and Development – Environmental Technology Verification Program

EPA REVIEW NOTICE

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THE ENVIRONMENTAL TECHNOLOGY VERIFICATION PROGRAM

Environmental and Sustainable Technology Evaluation (ESTE)

U.S. Environmental Protection Agency

SOUTHERN RESEARCH INSTITUTE

ESTE Joint Verification Statement

TECHNOLOGY TYPE:	Biomass Co-firing
APPLICATION:	Industrial Boilers
TECHNOLOGY NAME:	Renewafuels Pelletized Wood Fuel
COMPANY:	Renewafuels, LLC
ADDRESS:	13420 Courthouse Boulevard Rosemount, MN 55068

The U.S. Environmental Protection Agency (EPA) has created the Environmental Technology Verification (ETV) program to facilitate the deployment of innovative or improved environmental technologies through performance verification and dissemination of information. The goal of the ETV program is to further environmental protection by accelerating the acceptance and use of improved and cost-effective technologies. ETV seeks to achieve this goal by providing high-quality, peer-reviewed data on technology performance to those involved in the purchase, design, distribution, financing, permitting, and use of environmental technologies. This verification was conducted under the Environmental and Sustainable Technology Evaluation (ESTE) program, a component of ETV that was designed to address agency priorities for technology verification.

The goal of the ESTE program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. The ESTE program was developed in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permitters in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

This ESTE project involved evaluation of co-firing common woody biomass in industrial, commercial or institutional coal-fired boilers. For this project ERG was the responsible contractor and Southern Research Institute (Southern) performed the work under subcontract. Client offices within the EPA, those with an explicit interest in this project and its results, include: Office of Air and Radiation (OAR), Combined Heat and Power (CHP) Partnership, Office of Air Quality Planning and Standards (OAQPS), Combustion Group, Office of Solid Waste (OSW), Municipal and Industrial Solid Waste Division, and ORD's Sustainable Technology Division. Letters of support have been received from the U.S. Department of Agriculture Forest Service and the Council of Industrial Boiler Owners.

TECHNOLOGY DESCRIPTION

Wood Pellets from a Renewafuel, LLC facility in Michigan were used for this verification. The pellets were a pressed oak product which is made from the waste of trailer bed manufacturing. No glue or adhesives were used in the manufacture of the pellets. Proximate analyses of the pelletized wood used for this testing is as follows:

Component	% by Weight
Moisture	6.6
Ash	0.43
Volatile matter	75.5
Fixed carbon	17.3

The average heating value was 7,688 British thermal units per pound (Btu/lb).

Testing was conducted at the University of Iowa (UI) Main Power Plant's Boiler 10. The UI Main Power Plant is a combined heat and power (CHP) facility which serves the main campus and the UI hospitals and clinics. The plant continuously supplies steam service and cogenerated electric power. There are four operational boilers at the facility, one stoker unit (Boiler 10), one circulating fluidized bed boiler (Boiler 11), and two gas package boilers (Boilers 7 and 8). Boiler 10 was used during this co-firing demonstration. Boiler 10 is a Riley Stoker Corporation unit rated at 170,000 lb/h steam (206 MMBtu/h heat input) at 750 degrees Fahrenheit (°F) and 600 pounds per square inch, gauge (psig). This unit normally operates in pressure control (swing) mode on a multi-boiler header at a typical operating range of 120,000 to 140,000 lb/h steam. The unit can be base loaded up to its rated capacity or swing down to a minimum load of 90,000lb/h. The facility includes a mechanical dust collector and electrostatic precipitator (ESP) to control particulate emissions. Bottom ash and fly ash generated by Boilers 10 and 11 are collected, blended, and shipped to a nearby limestone quarry where it is mixed with water, solidified, and used to build roads or fill.

Forty-four tons (T) of Renewafuel's wood based pellets were delivered to the River Trading site and mixed with stoker coal using a front end loader. The weight of the total mixture was 294 T, for a pellet fraction by weight of approximately 15 %.

VERIFICATION DESCRIPTION

This project was designed to evaluate changes in boiler performance due to co-firing woody biomass with coal. Boiler operational performance with regard to efficiency, emissions, and fly ash characteristics were evaluated while combusting 100 percent coal and then reevaluated while co-firing biomass with coal. The verification also addressed sustainability issues associated with biomass co-firing at this site.

The testing was limited to two operating points on Boiler 10:

- firing coal only at a typical nominal load
- firing a coal:biomass "co-firing" mixture of approximately 85:15 percent by weight at the same operating load

Under each condition, testing was conducted in triplicate with each test run approximately three hours in duration. In addition to the emissions evaluation, this verification addressed changes in fly ash composition. Fly ash can serve as a portland cement production component, structural fill, road materials, soil stabilization, and other beneficial uses. An important property that limits the use of fly ash is carbon content. Presence of metals in the ash, particularly mercury (Hg), can also limit fly ash use, such as in cement manufacturing. Biomass co-firing could impact fly ash composition and properties, so this verification included evaluation of changes in fly ash carbon burnout (loss on ignition), minerals, and metals content.

During testing, the verification parameters listed below were evaluated. This list was developed based on project objectives cited by the client organizations and input from the Biomass Co-firing Stakeholder Group (BCSG).

<u>Verification Parameters:</u>

- Changes in emissions due to biomass co-firing including:
  - Nitrogen oxides (NO_X)
  - Sulfur dioxide (SO_2)
  - Carbon monoxide (CO)
  - Carbon dioxide (CO_2)
  - Total particulates (TPM) (including condensable particulates)
  - Primary metals: arsenic (As), selenium (Se), zinc (Zn), and Hg
  - Secondary metals: barium (Ba), beryllium (Be), cadmium (Cd), chromium (Cr), copper (Cu), manganese (Mn), nickel (Ni), and silver (Ag)
  - Hydrogen chloride (HCl) and hydrogen fluoride (HF)
- Boiler efficiency
- Changes in fly ash characteristics including:
  - Carbon, hydrogen, and nitrogen (CHN), and SiO_2, Al_2O_3, and Fe_2O_3 content
  - Primary metals: As, Se, Zn, and Hg
  - Secondary metals: Ba, Be, Cd, Cr, Cu, Mn, Ni, and Ag
  - fly ash fusion temperature
  - Resource Conservation Recovery Act (RCRA) metals and Toxic Characteristic Leaching Procedure (TCLP).
- Sustainability indicators including CO_2 emissions associated with sourcing and transportation of biomass and ash disposal under baseline (no biomass co-firing) and test case (with biomass co-firing) conditions.

Rationale for the experimental design, determination of verification parameters, detailed testing procedures, test log forms, and QA/QC procedures can be found in Test and Quality Assurance Plan titled *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation Biomass Co-firing in Industrial Boilers.*

Quality Assurance (QA) oversight of the verification testing was provided following specifications in the ETV Quality Management Plan (QMP). Southern's QA Manager conducted an audit of data quality on a representative portion of the data generated during this verification and a review of this report. Data review and validation was conducted at three levels including the field team leader (for data generated by subcontractors), the project manager, and the QA manager. Through these activities, the QA manager has concluded that the data meet the data quality objectives that are specified in the Test and Quality Assurance Plan.

VERIFICATION OF PERFORMANCE

Boiler Efficiency

For the efficiency testing, mass feed of blended coal and wood was increased to attempt to repeat heat input as closely as possible to the baseline coal only tests.

Table S-1. Boiler Efficiency

Test ID	Fuel	Heat Input (MMBtu/hr)	Heat Output (MMBtu/hr)	Efficiency (%)
Baseline 1	100 % Coal	264.6	224.4	84.8
Baseline 2		264.2	223.9	84.8
Baseline 3		264.8	223.7	84.5
Baseline 4		267.6	228.8	85.5
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	275.7	229.7	83.3
Cofire 2		271.9	230.0	84.6
Cofire 3		272.5	230.3	84.5
Baseline Average		265.3	225.2	84.9 ±0.4
Cofire Average		273.4	230.0	84.1 +0.7
Absolute Difference		8.1	4.8	-0.7
% Difference		3.0%	2.1%	-0.9%
Statistically Significant Change?		na	na	No

The average efficiencies during baseline (coal only) and co-firing tests were 84.9 ± 0.4 and 84.1 ± 0.7 percent respectively. This change is not statistically significant, so it is concluded that co-firing biomass at the 15 percent blending rate did not impact boiler efficiency performance.

Emissions Performance

Table S-2. Gaseous Pollutant Emissions (lb/MMBtu)

Test ID	Fuel	SO_2	CO_2	NO_x	CO
Baseline 1	100 % Coal	2.49	207	0.473	0.081
Baseline 2		2.28	206	0.442	0.083
Baseline 3		2.48	206	0.438	0.085
Baseline 4		2.63	202	0.486	0.102
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	2.12	207	0.487	0.089
Cofire 2		2.11	207	0.525	0.081
Cofire 3		2.26	207	0.506	0.081
Baseline Averages		2.47 ± 0.14	205 ± 2	0.460 ± 0.02	0.088 ± 0.010
Cofire Averages		2.16 ± 0.08	207 ± 0.3	0.506 ± 0.018	0.083 ± 0.05
% Difference		-12.4%	0.82%	10.2%	-5.02%
Statistically Significant Change?		Yes	No	Yes	No

SO_2 emissions were about 13 percent lower while combusting the blended fuel, which correlates well with the approximately 15 percent biomass to coal ratio. The reduction in SO_2 indicates that co-firing woody biomass may be a viable option for reducing SO_2 emissions without adding emission control technologies. NO_X emissions had a statistically significant increase when co-firing. Increases are presumably due to the higher temperatures within the boiler that were experienced while firing the dryer, lighter blended fuel. Changes in CO and CO_2 emissions were not statistically significant.

Table S-3. Particulate Emissions (lb/MMBtu)

Test ID	Fuel	Total Particulate	Filterable PM	Condensable PM
Baseline 1	100 % Coal	0.090	0.038	0.051
Baseline 2		0.039	0.023	0.016
Baseline 3		0.054	0.031	0.022
Baseline 3		Not Tested		
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	0.046	0.026	0.021
Cofire 2		0.044	0.023	0.020
Cofire 3		0.041	0.023	0.018
Baseline Averages		0.061 ± 0.03	0.031 ± 0.008	0.030 ± 0.02
Cofire Averages		0.044 ± 0.003	0.024 ± 0.0018	0.020 ± 0.0012
Absolute Difference		-1.71E-02	-7.03E-03	-1.01E-02
% Difference		-28.1%	-22.8%	-33.9%
Statistically Significant Change?		No	No	No

Although not statistically significant, particulate emission fractions were generally lower while co-firing the blended fuel. This is likely caused by the lower ash content of the blended fuels. It could also be the result of better combustion or better ESP performance due to changes in firebox temperatures or flyash characteristics.

Metals emissions were relatively low during all test periods. The only statistically significant change in metals emissions was a decrease in selenium. Emissions of HCl and HF were considerably lower during co-firing decreasing by approximately 9 and 29 percent, respectively.

Fly Ash Characteristics

Changes in ash characteristics were generally small, which is favorable for most operating systems (ash handling systems would not be expected to be impacted by co-firing at this rate). Carbon content and ash loss on ignition were both reduced significantly during biomass co-firing, although neither ash met the Class F requirements for use in concrete. Quantitative flyash results are voluminous and not presented here, but can be viewed in the main body of the report in Tables 3-7 through 3-9.

Biomass co-firing during this verification did not impact the quality of the ash with regard to fly ash TCLP metals (40 CFR 261.24) and Class F Requirements (C 618-05). Metals content of the ash was well below the TCLP criteria during all test periods and changes were not significant. The ash generated during co-firing did have a significantly higher SO_3 content, but was still well below the Class F requirement.

Sustainability Issues

- The wood pellets used for testing at the University of Iowa were produced from waste wood waste at a rate of 4.5 tons per hour. The equipment used to produce the pellets is rated at 250 horsepower and was operated at 80 percent of capacity. Based on electrical consumption of 0.746 kWh/hp multiplied by 200 hp, the energy use per hour to produce the pellets was 149.14 kWh or 33.14 kWh/ton. Based on an Energy Information Administration emission factor for Michigan (location of the production facility) of 1.58 lbs CO_2/kWh, CO_2 emissions per ton of pellets produced is 52.36 lbs.

- Wood-based pellets were transported from Battle Creek Michigan to Muscatine, Iowa (where the University of Iowa's coal supplier is located). 43 tons of wood-based pellets were shipped with two trucks using 350 Cummins motors. The trucks averaged 6.5 miles per gallon. The distance from Battle Creek to Muscatine is 345 miles. Therefore:

  345 miles * 2 trucks = 690 miles, divided by 6.5 mpg = 106.15 gallons, divided by 43 tons fuel = 2.47 gallons/ton.

  Renewafuel has a 28-acre site for possible future operations in Anamosa, Iowa. The distance from Anamosa to Muscatine is 65 miles. Here, Renewafuel can load as much as 25 tons of fuel per truck. Assuming use of the same truck with 6.5 miles per gallon the fuel used per ton of fuel transported from Anamosa to Muscatine, fuel usage from Anamosa is then:

  65 miles, divided by 6.5 mpg = 10 gallons, divided by 25 tons per truck = 0.4 gallons/ton

- Based on an Energy Information Administration emission factor of 19.564 lbs CO_2/gallon, CO_2 emissions per ton of pellets transported to the facility are:

  48.3 lbs/ton for Battle Creek (2.47 gal fuel /ton pellets * 19.564 lbs CO_2/gal).
  7.82 lbs/ton for Anamosa (0.4 gal/ton * 19.564 lbs CO_2/gal).

- Based on data generated during this testing, the CO_2 emission rates while firing straight coal and blended fuel (at a blending rate of approximately 15 percent wood by mass) were 205 and 207 lb/MMBtu, respectively. However, combustion of Renewafuel wood pellets, which are comprised of biogenic carbon—meaning it is part of the natural carbon balance and will not add to atmospheric concentrations of CO_2—emits no creditable CO_2 emissions under international greenhouse gas accounting methods developed by the IPCC and adopted by the CFPA [6]. The slight increase in CO2 emissions is likely also impacted by the increased mass fuel feed rates during co-firing. By analyzing the heat content of the coal and the wood, the total boiler heat input for the test periods, and boiler efficiency, it was determined that approximately 10 percent of the heat generated during co-firing test periods is attributable to the Renewafuel pellets fuel. It is therefore estimated that the CO_2 emissions offset during this testing is approximately 10 percent, or 20.7 lb/MMBtu at this co-firing blend.

- UI Boiler 10 typically operates in the 160 to 190 MMBtu/hr heat generating rate. Assuming an availability and utilization rate of 80 percent for Boiler 10, this would equate to estimated annual CO_2 emission reductions of approximately 11,000 to 13,000 tons per year. CO_2 offsets from use of wood pellets could be even greater had the analysis included emissions associated with coal mining and transportation.

- Regarding use and or disposal of fly ash, biomass co-firing did not impact either sustainability issue since the quality of the ash with regard to fly ash TCLP metals and Class F Requirements was unchanged.

Details on the verification test design, measurement test procedures, and Quality Assurance/Quality Control (QA/QC) procedures can be found in the Test Plan titled *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation Biomass Co-firing in Industrial Boilers.* (Southern 2006). Detailed results of the verification are presented in the Final Report titled *Environmental and Sustainable Technology Evaluation Biomass Co-firing in Industrial Boilers – University of Iowa* (Southern 2007). Both can be downloaded from the Southern's web-site (www.sri-rtp.com) or the ETV Program web-site (www.epa.gov/etv).

Signed by: Sally Gutierrez – April 28, 2008	Tim Hansen – April 3, 2008
Sally Gutierrez Director National Risk Management Research Laboratory Office of Research and Development	Tim Hansen Program Director Southern Research Institute

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Environmental and Sustainable Technology Evaluation

Biomass Co-firing in Industrial Boilers

University of Iowa Unit 10

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Acronyms and Abbreviations

Ag	silver
As	arsenic
Ba	barium
Be	beryllium
BCSG	Biomass Co-firing Stakeholder Group
Btu	British thermal unit
Btu/h	British thermal unit per hour
Cd	cadmium
CEMS	continuous emissions monitoring system
CHN	carbon, hydrogen, and nitrogen
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
Cr	chromium
Cu	copper
DQO	data quality objective
EPA-ORD	Environmental Protection Agency Office of Research and Development
ESP	electrostatic precipitator
ESTE	Environmental and Sustainable Technology Evaluation
ETV	Environmental Technology Verification
gr/dscf	grains per dry standard cubic foot
HCl	hydrogen chloride
HF	hydrogen fluoride
Hg	mercury
ICI	industrial-commercial-institutional
kW	kilowatt
lb/h	pounds per hour
lb/lb-mol	pounds per pound-mole
MMBtu/h	million British thermal units per hour
Mn	manganese
MQO	measurement quality objective
MW	megawatt
Ni	nickel
NO_X	nitrogen oxides
O_2	oxygen
QA / QC	quality assurance / quality control
OAQPS	Office of Air Quality Planning and Standards
OAR	Office of Air and Radiation
OSW	Office of Solid Waste
ppmvd	parts per million by volume, dry
psig	pounds per square inch, gauge
Se	selenium
SO_2	sulfur dioxide
T	tons (English)
TCLP	Toxic Characteristic Leaching Procedure
TPM	total particulate matter
TQAP	test and quality assurance plan
UI	University of Iowa
Zn	zinc
^oF	degrees Fahrenheit

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1.0 INTRODUCTION

1.1 BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates the Environmental and Sustainable Technology Evaluation (ESTE) program to facilitate the deployment of innovative technologies through performance verification and information dissemination. In part, the ESTE program is intended to increase the relevance of Environmental Technology Verification (ETV) Program projects to the U.S. EPA program and regional offices.

The goal of the ESTE program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. The ESTE program was developed in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permitters in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

The ESTE program involves a three step process. The first step is a technology category selection process conducted by ORD. The second step involves selection of the project team and gathering of project collaborators and stakeholders. Collaborators can include technology developers, vendors, owners, and users. They support the project through funding, cost sharing, and technical support. Stakeholders can include representatives of regulatory agencies, trade organizations relevant to the technology, and other associated technical experts. The project team relies on stakeholder input to improve the relevance, defensibility, and usefulness of project outcomes. Both collaborators and stakeholders are critical to development of the project test and quality assurance plan (TQAP), the end result of step two. Step three includes the execution of the verification and quality assurance and review process for the final reports.

This ESTE project involved evaluation of co-firing common woody biomass in industrial, commercial or institutional coal-fired boilers. For this project ERG was the responsible contractor and Southern Research Institute (Southern) performed the work under subcontract. Client offices within the EPA, those with an explicit interest in this project and its results, include: Office of Air and Radiation (OAR), Combined Heat and Power (CHP) Partnership, Office of Air Quality Planning and Standards (OAQPS), Combustion Group, Office of Solid Waste (OSW), Municipal and Industrial Solid Waste Division, and ORD's Sustainable Technology Division. Letters of support have been received from the U.S. Department of Agriculture Forest Service and the Council of Industrial Boiler Owners.

With increasing concern about global warming and fossil fuel energy supplies, there continues to be an increasing interest in biomass as a renewable and sustainable energy source. Many studies and research projects regarding the efficacy and environmental impacts of biomass co-firing have been conducted on large utility boilers, but less data is available regarding biomass co-firing in industrial size boilers. As such, OAQPS has emphasized an interest in biomass co-firing in industrial-commercial-institutional (ICI) boilers in the 100 to 1000 million British thermal units per hour (MMBtu/h) range. The reason for this emphasis is to provide support for development of a new area-source "Maximum Achievable Control Technology" standard.

The focus for this project was to evaluate performance and emission reductions for ICI boilers as a result of biomass co-firing. The primary objectives of this project were to:

- Evaluate changes in boiler emissions due to biomass co-firing
- Evaluate boiler efficiency with biomass co-firing
- Examine any impact on the value and suitability of fly ash for beneficial uses (carbon and metals content)
- Evaluate sustainability indicators including emissions from sourcing and transportation of biomass and disposal of fly ash

This document is one of two Technology Evaluation Reports for this ESTE project. This report presents results of the testing conducted on Unit 10 at the University of Iowa's Power Plant in Iowa City. This report includes the following components:

- Brief description of the verification approach and parameters (§ 2.0)
- Description of the test location (§ 2.1)
- Brief description of sampling and analytical procedures (§ 2.2)
- Test results (§ 3.0)
- Data quality (§ 4.0)

This report has been reviewed by representatives of ORD, OAQPS, OSW, the EPA QA team, and the project stakeholders and collaborators. It documents test operations and verification results. It is available in electronic format from Internet sites maintained by Southern Research Institute (Southern) (www.sri-rtp.com) and ETV program (www.epa.gov/etv).

2.0 VERIFICATION APPROACH

This project was designed to evaluate changes in boiler performance due to co-firing woody biomass with coal. Boiler operational performance with regard to efficiency, emissions, and fly ash characteristics were evaluated while combusting 100 percent coal and then reevaluated while co-firing biomass with coal. The verification also addressed sustainability issues associated with biomass co-firing at this site.

The testing was limited to two operating points on Boiler 10 at U of I:

- firing coal only at a typical nominal load
- firing a coal:biomass "co-firing" mixture of approximately 85:15 percent by weight at the same operating load

In addition to the emissions evaluation, this verification addressed changes in fly ash composition. Fly ash can serve as a portland cement production component, structural fill, road materials, soil stabilization, and other beneficial uses. An important property that limits the use of fly ash is carbon content. Presence of metals in the ash, particularly mercury (Hg), can also limit fly ash use, such as in cement manufacturing. Biomass co-firing could impact fly ash composition and properties, so this verification included evaluation of changes in fly ash carbon burnout (loss on ignition), minerals, and metals content.

During testing, the verification parameters listed below were evaluated. This list was developed based on project objectives cited by the client organizations and input from the Biomass Co-firing Stakeholder Group (BCSG).

<u>Verification Parameters:</u>

- Changes in emissions due to biomass co-firing including:
  - Nitrogen oxides (NO_X)
  - Sulfur dioxide (SO_2)
  - Carbon monoxide (CO)
  - Carbon dioxide (CO_2)
  - Total particulates (TPM) (including condensable particulates)
  - Primary metals: arsenic (As), selenium (Se), zinc (Zn), and Hg
  - Secondary metals: barium (Ba), beryllium (Be), cadmium (Cd), chromium (Cr), copper (Cu), manganese (Mn), nickel (Ni), and silver (Ag)
  - Hydrogen chloride (HCl) and hydrogen fluoride (HF)
- Boiler efficiency
- Changes in fly ash characteristics including:
  - Carbon, hydrogen, and nitrogen (CHN), and SiO_2, Al_2O_3, and Fe_2O_3 content
  - Primary metals: As, Se, Zn, and Hg
  - Secondary metals: Ba, Be, Cd, Cr, Cu, Mn, Ni, and Ag
  - fly ash fusion temperature
  - Resource Conservation Recovery Act (RCRA) metals and Toxic Characteristic Leaching Procedure (TCLP).

- Sustainability indicators including CO_2 emissions associated with sourcing and transportation of biomass and ash disposal under baseline (no biomass co-firing) and test case (with biomass co-firing) conditions.

2.1 HOST FACILITY AND TEST BOILER

Testing was conducted on two industrial boilers that are capable of co-firing woody biomass using two different biomass types and blends. The two units that hosted tests were Minnesota Power's Rapids Energy Center Boiler 5 (MP-5) and the University of Iowa (UI) Main Power Plant's Boiler 10. Results of the Rapids Energy Center testing are published under separate cover and can be found at www.sri-rtp.com.

The UI Main Power Plant is a combined heat and power (CHP) facility which serves the main campus and the UI hospitals and clinics. The plant continuously supplies steam service and cogenerated electric power. There are four operational boilers at the facility, one stoker unit (Boiler 10), one circulating fluidized bed boiler (Boiler 11), and two gas package boilers (Boilers 7 and 8). Three controlled extraction turbine generators with 24.7 megawatt (MW) capacity cogenerate about 30 percent of the university and hospital facilities total electric needs.

Figure 2-1. The University of Iowa Main Power Plant

Boiler 10 is a Riley Stoker Corporation unit rated at 170,000 lb/h steam (206 MMBtu/h heat input) at 750 degrees Fahrenheit (°F) and 600 pounds per square inch, gauge (psig). This unit normally operates in pressure control (swing) mode on a multi-boiler header at a typical operating range of 120,000 to 140,000 lb/h steam. The unit can be base loaded up to its rated capacity or swing down to a minimum load of 90,000lb/h.

This boiler is currently fired with Appalachian coal mined in West Virginia and Pennsylvania and barged to Muscatine, Iowa for distribution. However, UI has been successful in converting the fluidized bed boiler (Boiler 11) at the facility to a co-firing unit using an oat hull product generated at a nearby food processing plant. In keeping with the economic and environmental benefits realized through this effort, UI is interested in introducing biomass co-firing on Boiler 10. A pelletized wood product manufactured from woody biomass by Renewafuels, LLC in Minnesota has been identified as a suitable co-firing fuel for Boiler 10.

Emissions testing for this program was conducted in the ductwork of the selected boiler upstream of the stack. The testing location and ports are shown in Figure 2-2.

Figure 2-2. Test Port Locations for Boiler 10

The facility includes a mechanical dust collector and electrostatic precipitator (ESP) to control particulate emissions. Bottom ash and fly ash generated by Boilers 10 and 11 are collected, blended, and shipped to a nearby limestone quarry where it is mixed with water, solidified, and used to build roads or fill.

Boiler 10 is equipped with a continuous emissions monitoring system (CEMS) that monitors flue gas SO_2 and O_2 concentrations. Table 2-1 summarizes the Boiler 10 CEMS specifications.

Table 2-1. UI-10 CEMS

Parameter	Instrument Make/Model	Instrument Range	Reporting Units
SO_2	TML 50-H	0 – 1000 ppm	lb/MMBtu
O_2	TML 41-HO2	0 – 25 %	%

The facility has a fully equipped control room that continuously monitors boiler operations. The system's distributed control system includes a PI Historian software package that allows the facility to customize data acquisition, storage, and reporting activities. Operational parameters that were recorded during this test program include the following:

- Heat input, Btu/h
- Steam flow, lb/h
- Steam pressures, psig, and temperatures, ^oF
- Air flows, lb/h, and temperatures, ^oF
- Power output, MW
- SO_2 emissions, pounds per million Btu (lb/MMBtu)
- ESP variables (volts, amperes, number of fields on line), recorded manually

These data were recorded using the PI Historian during each test period. One minute readings were recorded during each test period using an assigned start and end tag, and then averaged over the test period to document boiler operations during the testing, co-firing rates, and boiler efficiency. Key parameters such as heat input and steam flow are summarized in the results section of this report. ESP operational data are summarized in Appendix D.

2.2 FIELD TESTING

Wood pellets from a Renewafuel, LLC facility in Michigan were shipped to the River Trading Co. coal yard in Muscatine, IA (the facility's coal supplier). The pellets were a pressed oak product which is made from the waste of trailer bed manufacturing. No glue or adhesives were used in the manufacture of the pellets. A sample of pellets is shown in Figure 2-3.

Figure 2-3. Renewafuel Pelletized Wood

Proximate analyses of the pelletized wood used for this testing is as follows:

Component	% by Weight
Moisture	6.6
Ash	0.43
Volatile matter	75.5

Fixed carbon 17.3

The average heating value was 7,688 British thermal units per pound (Btu/lb).

Forty-four tons (T) of Renewafuel's wood based pellets were delivered to the River Trading site and mixed with stoker coal using a front end loader. The weight of the total mixture was 294 T, for a pellet fraction by weight of approximately 15 %. Table 3-1 summarizes the composition of the sites coal supply and the blended fuel. The fuel mix was delivered by truck and stored in Silo #3 at the facility. Over the next two days the mixed fuel was transferred by operations staff to the south bunker.

2.2.1 Field Testing Matrix

A set of three replicate tests were conducted while firing coal only on March 13, 2007. The following day, a second set of three tests were conducted while co-firing biomass and coal. Duration of each test run was approximately 180 minutes. Other than changes in fuel composition, all other boiler operations were replicated as closely as possible during test sets. Test and sampling procedures were also consistent between sets of tests. A fourth run on straight coal was conducted on March 15 to repeat the metals testing conducted during Baseline test 3 on the 13th because broken glassware had invalidated that test run. Table 2-2 summarizes the test matrix.

Table 2-2. University of Iowa Boiler 10 Test Periods

Date	Time	Test ID	Fuel	Steam Flow (Klb/h)
3-13-07	08:20 – 11:14	Baseline 1	100 % coal	159.9
	12:12 – 14:55	Baseline 2		159.9
	15:30 - 18:00	Baseline 3		159.7
3-14-07	08:15 – 11:00	Cofire 1	Blended fuel (85.1coal:14.9 wood)	163.0
	11:50 – 14:25	Cofire 2		163.2
	15:10 – 17:35	Cofire 3		163.5
3-15-07	07:50 - 10:10	Baseline 4	100% coal	162.8

All testing was conducted during stable boiler operations (defined as boiler steam flows varying by less than 5 percent over a 5 minute period). Southern representatives coordinated testing activities with boiler operators to ensure that all testing was conducted at the desired boiler operating set points and the boiler operational data needed to calculate efficiency was properly logged and stored. Southern also supervised all emissions testing activities.

2.3 BOILER PERFORMANCE TEST PROCEDURES

Conventional field testing protocols and reference methods were used to determine boiler efficiency, emissions, and fly ash properties. A brief description of the methods and procedures is provided here. Details regarding the protocols and methods proposed are provided in the document titled: *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation – Biomass Co-firing in Industrial Boilers* [1].

2.3.1 Boiler Efficiency

Boiler efficiency was determined following the Btu method in the B&W Steam manual [2]. The efficiency determinations were also used to estimate boiler heat input during each test period. The facility logs all of the data required for determination of boiler efficiency on a regular basis. Certain parameters such as ambient conditions and flue gas temperatures were independently measured by Southern. Table 2-3 summarizes the boiler operational parameters logged during testing and the source and logging frequency for each.

Table 2-3. Summary of Boiler Efficiency Parameters

Operational Parameter	Source of Data	Logging Frequency
Intake air temperature, °F	Southern measurements	Five minute intervals
Flue gas temperature at air heater inlet, °F		
Fuel temperature, °F	Southern measurements	Twice per test run
Moisture in air, lb/lb dry air		
Fuel consumption, lb/h	Facility PI Historian Control System	One minute averages
Combustion air temperature, °F		
Steam flow, MMBtu/h or lb/h		
Steam pressure, psig		
Steam temperature, °F		
Supply water pressure, psig		
Supply water temperature, °F		
Power generation, kW		
Fuel ultimate analyses, both wood and coal	Analytical laboratory	One composite coal, mixed fuel, and fly ash sample per test (3 total for each condition)
Fuel heating value, Btu/lb		
Unburned carbon loss, %		

2.3.1.1 Fuel Sampling and Analyses

Fuel samples were collected during each test run for ultimate and heating value analysis. A composite of grab samples of coal and biomass were prepared during co-firing test runs and submitted to Wyoming Analytical Laboratories, Inc. in Laramie, Wyoming for the analyses shown in Table 2-4.

Table 2-4. Summary of Fuel Analyses

Parameter	Method
Ultimate analysis	ASTM D3176
Gross calorific value	ASTM D5865 (coal) ASTM E711-87 (biomass)

Grab samples of each fuel (straight coal and blended fuel) were collected from the solid fuel conveyer immediately above the stoker feed hopper. The grabs contained approximately one lb of fuel and were collected at 30 minute intervals during each test run and combined in a large pail. One mixed composite sample of approximately one lb of each fuel was generated for each test run, sealed and submitted for analysis. Collected composite samples were labeled, packed and shipped to Wyoming Analytical along with completed chain-of-custody documentation for off-site analysis. Because the blended fuel is delivered premixed, pelletized wood fuel samples were collected at the fuel blending facility (coal yard) and sealed in plastic zip lock bags. These samples were submitted to the field team leader for subsequent analysis. The ultimate analysis reported the following fuel constituents as percent by weight:

- carbon
- sulfur
- hydrogen
- ash
- water
- nitrogen
- oxygen

The efficiency analysis requires the unburned carbon loss value, or carbon content of fly ash. Fly ash samples were also collected during each test run and submitted for analysis. Prior to each test run, precipitator ash hoppers were cleared of residual ash. Grab samples of ash were then collected from a hopper at 30 minute intervals during each test run and combined in a gallon size metal ash sampling can. Collected ash samples were then sealed in plastic bags, labeled, packed and shipped to Wyoming Analytical along with completed chain-of-custody documentation for off-site analysis. Results of these analyses were used to complete the combustion gas calculations in the Btu method.

2.3.2 Boiler Emissions

Measurements required for emissions tests include:

- fuel heat input, Btu/h (via boiler efficiency, Section 2.3.1)
- gaseous pollutant concentrations, parts per million by volume, dry (ppmvd)
- TPM and condensible particulate concentrations, grains per dry standard cubic foot (gr/dscf)
- CO_2 concentrations, percent
- flue gas molecular weight, pounds per pound-mole (lb/lb-mol)
- flue gas moisture concentration, percent
- flue gas flow rate, dry standard cubic feet per hour

The average emission rates for each pollutant are also reported in units of pounds per hour (lb/h), and pounds per million Btu (lb/MMBtu).

All testing was conducted by GE Energy following EPA Reference or Conditional Methods for emissions testing [3]. Table 2-5 summarizes the reference methods used and the fundamental analytical principle for each method.

Table 2-5. Summary of Emission Test Methods and Analytical Equipment

Parameter or Measurement	U.S. EPA Reference Method	Principle of Detection
CO_2	3A	Non-dispersive infra-red
TPM	5	Gravimetric
Condensable PM	CTM040/202	Gravimetric
Metals	29	Inductively coupled plasma / cold vapor atomic absorption spectroscopy
HCl, HF	26	Ion chromatography
Moisture	4	Gravimetric
Flue gas flow rate	2	Pitot traverse

2.3.3 Fly ash Characteristics

Fly ash samples were collected during the efficiency and emissions testing periods to evaluate the impact of biomass co-firing on ash composition. Fly ash samples were collected from the electrostatic precipitator (ESP) collection hoppers during each test run. Hoppers were cleaned out between runs. Collected samples were submitted to Wyoming Analytical along with completed chain-of-custody documentation for determination of the parameters listed below. The laboratory also conducted tests to evaluate ash fusion temperature. Results are compared to the Class F (bituminous and anthracite) or Class C (lignite and sub bituminous) fly ash specifications. Table 2-6 summarizes the analytical methods that were used.

Table 2-6. Summary of Fly ash Analyses

Parameter	Method
CHN	ASTM D5373
Minerals	ASTM D4326-04
RCRA metals	SW-846 3052/6010
Metals TCLP	SW-846 1311/6010
Fly ash fusion temperature	ASTM D1857

2.4 SUSTAINABILITY INDICATORS AND ISSUES

Sustainability is an important consideration regarding use of woody biomass as a renewable fuel source. This project evaluated certain sustainability issues for the two sites selected for field testing. The following sustainability related issues were examined:

- Estimated daily and annual woody biomass consumption at the nominal co-firing rate
- Biomass delivery requirements (distance and mode)
- Coal delivery requirements (distance and mode)
- Fly ash composition, use, and waste disposal including delivery distance and mode.

Biomass Consumption, Type, and Source

The projected daily and annual biomass consumption rate is useful in determining whether the supply of biomass is sustainable. Biomass consumption rates measured during the testing conducted at each site were used as the basis to estimate daily and annual biomass consumption. The source, type, and compositional analyses of the biomass was documented during testing.

Associated Biomass CO_X Emissions

By evaluating the average biomass consumption rate during the testing, upstream CO_2 emissions associated with the biomass supply were estimated. The distance between the biomass source and the boiler tested along with CO_2 emission factors for the modes of transportation used to deliver the biomass were used to complete this analysis. Emission factors were determined based on EPA's AP 42 Emission Factors Database [4].

Solid Waste Issues (Ash utilization)

Results of the baseline coal fly ash analyses and the co-fired fuel fly ash analyses were compared to determine if co-firing biomass has a measurable impact on the carbon content of the ash with respect to

ASTM standards for cement admixtures. In addition, results of the RCRA metals analyses for the baseline and co-fire ash were compared to evaluate impact on metals content. The metals TCLP analytical results were used to examine if co-firing impacts fly ash characteristics with respect to the TCLP standards cited in 40 CFR 261.24 [5].

3.0 RESULTS

Results of the testing are summarized in the following sections. Where results are used to evaluate whether biomass co-firing resulted in significant changes in boiler performance, a statistical t-test was applied with a 90 percent confidence interval. Field and analytical data generated during the verification are presented in Appendices A through C. In general, the facility was able to process and utilize the blended fuel with minimal problems. No physical changes to fuel handling or boiler equipment were necessary to accommodate use of the pelletized biomass fuel. The mix was very dry due to concerns associated with mixing the wood pellets with water, but the crew on shift kept the mix flowing to the boiler and a successful three test runs were completed.

An additional coal only test run was performed as a precaution because a portion of the metals sampling train was spilled during recovery of run 2. Once all runs were completed, test personnel confirmed that all needed data and samples had been collected.

As part of the data analysis, results were analyzed to evaluate changes in boiler performance and fly ash characteristics between the two sets of tests. Standard deviations of the replicate measurements conducted under each fueling condition and a statistical analysis (t-test) with a 90 percent confidence interval were used to verify the statistical significance of any observed changes in emissions or efficiency.

3.1 BOILER EFFICIENCY

Table 3-1 summarizes the major fuel characteristics for both coal and blended fuel. Detailed fuel analyses, including results on a dry basis, are presented in Appendix B.

Table 3-1 Fuel Characteristics (As received)

Test ID	Fuel	Moisture (%)	Carbon (%)	Nitrogen (%)	Sulfur (%)	Ash (%)	Heating Value (Btu/lb)
Baseline 1	100 % Coal	13.8	63.8	1.45	1.48	7.0	11,242
Baseline 2		13.9	63.7	1.31	1.50	6.7	11,287
Baseline 3		14.4	61.8	1.20	1.05	6.4	10,935
Baseline 4		13.8	62.3	1.24	1.48	7.3	11,153
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	13.6	59.8	1.23	1.40	6.6	10,615
Cofire 2		13.1	60.3	1.29	1.37	6.3	10,757
Cofire 3		13.2	59.2	1.11	1.38	6.1	10,555
Baseline Averages		13.9	62.8	1.29	1.40	6.9	11,154
Cofire Averages		13.3	59.8	1.21	1.38	6.4	10,642
% Difference		-4.6%	-4.7%	-6.1%	-1.0	-8.1%	-4.6%

The moisture, carbon content, and heating value of the blended fuel was consistently about 5 percent lower than those of the baseline coal. The blended fuel also had about 8 percent less ash content. Repeatability of the blended fuel results indicate that the fuel was evenly blended.

Efficiency data showed no significant change when burning the coal/wood pellet mix despite the fact that higher superheater and stack outlet temperatures were evident during the test. Combustion appeared to occur higher up the boiler than on coal, this was observed by the camera inside the boiler. Table 3-2 summarizes boiler efficiency during the test periods

Table 3-2. Boiler Efficiency

Test ID	Fuel	Heat Input (MMBtu/hr)	Heat Output (MMBtu/hr)	Efficiency (%)
Baseline 1	100 % Coal	264.6	224.4	84.8
Baseline 2		264.2	223.9	84.8
Baseline 3		264.8	223.7	84.5
Baseline 4		267.6	228.8	85.5
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	275.7	229.7	83.3
Cofire 2		271.9	230.0	84.6
Cofire 3		272.5	230.3	84.5
Baseline Average		265.3	225.2	84.9 ±0.4
Cofire Average		273.4	230.0	84.1 +0.7
Absolute Difference		8.1	4.8	-0.7
% Difference		3.0%	2.1%	-0.9%
Statistically Significant Change?		na	na	No

The average efficiencies during baseline (coal only) and co-firing tests were 84.9 ± 0.4 and 84.1 ± 0.7 percent respectively. This change is not statistically significant, so it is concluded that co-firing biomass at the 15 percent blending rate did not impact boiler efficiency performance.

3.2 BOILER EMISSIONS

Table 3-3 and Figure 3-1 summarizes emission rates for the gaseous pollutants evaluated. SO_2 emissions were about 13 percent lower while combusting the blended fuel, which correlates well with the approximately 15 percent biomass to coal ratio. The reduction in SO_2 emissions is statistically significant, and indicates that co-firing woody biomass may be a viable option for reducing SO_2 emissions without adding emission control technologies.

Table 3-3. Gaseous Pollutant Emissions (lb/MMBtu)

Test ID	Fuel	SO_2	CO_2	NO_x	CO
Baseline 1	100 % Coal	2.49	207	0.473	0.081
Baseline 2		2.28	206	0.442	0.083
Baseline 3		2.48	206	0.438	0.085
Baseline 4		2.63	202	0.486	0.102
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	2.12	207	0.487	0.089
Cofire 2		2.11	207	0.525	0.081
Cofire 3		2.26	207	0.506	0.081
Baseline Averages		2.47 ± 0.14	205 ± 2	0.460 ± 0.02	0.088 ± 0.010
Cofire Averages		2.16 ± 0.08	207 ± 0.3	0.506 ± 0.018	0.083 ± 0.05
% Difference		-12.4%	0.82%	10.2%	-5.02%
Statistically Significant Change?		Yes	No	Yes	No

NO_X emissions had a statistically significant increase when co-firing. Increases are presumably due to the higher temperatures within the boiler that were experienced while firing the dryer, lighter blended fuel. Also, boiler operators did not make significant changes to boiler operations to reduce flue gas temperatures or NO_X emissions. It's worth noting that in similar testing conducted at another facility, a much higher blend of wood was co-fired with the coal and the biomass had much higher moisture content (46 percent). In that case NO_X emissions were significantly reduced, indicating that if the Renewafuel pellets had a higher moisture content (i.e., had sat in a fuel yard for a time), NO_X emissions may have been reduced.

Changes in CO and CO_2 emissions were not statistically significant. Regarding CO_2 emissions, it should be noted that combustion of wood-based fuel, which is comprised of biogenic carbon emits no creditable CO_2 emissions under international greenhouse gas accounting methods developed by the Intergovernmental Panel of Climate Change (IPCC) and adopted by the International Council of Forest and Paper Associations (ICFPA). Therefore, the facility realizes a significant annual reduction in CO_2 emissions when co-firing wood (see Section 3.4.1)

Table 3-4 and Figure 3-2 summarizes results of filterable, condensable, and total particulate emissions.

Table 3-4. Particulate Emissions (lb/MMBtu)

Test ID	Fuel	Total Particulate	Filterable PM	Condensable PM
Baseline 1	100 % Coal	0.090	0.038	0.051
Baseline 2		0.039	0.023	0.016
Baseline 3		0.054	0.031	0.022
Baseline 4		Not Tested		
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	0.046	0.026	0.021
Cofire 2		0.044	0.023	0.020
Cofire 3		0.041	0.023	0.018
Baseline Averages		0.061 ± 0.03	0.031 ± 0.008	0.030 ± 0.02
Cofire Averages		0.044 ± 0.003	0.024 ± 0.0018	0.020 ± 0.0012
Absolute Difference		-1.71E-02	-7.03E-03	-1.01E-02
% Difference		-28.1%	-22.8%	-33.9%
Statistically Significant Change?		No	No	No

Although not statistically significant, particulate emission fractions were generally lower while co-firing the blended fuel. This is likely caused by the lower ash content of the blended fuels. It could also be the result of better combustion or better ESP performance due to changes in firebox temperatures or flyash characteristics. More testing and analysis will be needed to fully understand the impact of co-firing this biomass on particulate emissions. ESP operational data presented in Appendix D indicate that conditions were consistent between the two sets of runs with regard to ESP fields in operation and voltages.

Table 3-5. Primary Metals Emissions (lb/MMBtu)

Test ID	Fuel	Arsenic, As	Mercury, Hg	Selenium, Se	Zinc, Zn
Baseline 1	100 % Coal	7.75E-06	4.71E-06	6.02E-05	2.52E-05
Baseline 2		1.39E-05	4.48E-06	6.43E-05	2.17E-05
Baseline 3		1.84E-05	4.49E-06	7.40E-05	2.55E-05
Baseline 4		8.83E-06	1.15E-07	6.05E-05	1.81E-05
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	9.66E-06	4.21E-06	5.04E-05	2.44E-05
Cofire 2		7.10E-06	3.76E-06	4.28E-05	1.50E-05
Cofire 3		6.84E-06	3.87E-06	3.69E-05	1.55E-05
Baseline Averages		1.22E-05 ± 4.9E-06	3.45E-06 ± 2.2E-06	6.48E-05 ± 6.4E-06	2.26E-05 ± 3.5E-06
Cofire Averages		7.87E-06 ± 1.6E-06	3.957E-06 ± 2.4E-07	4.34E-05 ± 6.8E-06	1.83E-05 ±5.3E-06
Absolute Difference		-4.35E-06	4.98E-07	-2.14E-05	-4.33E-06
% Difference		-35.6%	14.4%	-33.0%	-19.1%
Statistically Significant Change?		No	No	Yes	No

Metals emissions (primary metals summarized in Table 3-5) were relatively low during all test periods. Changes in metals emissions on a percentage basis were large and variable from across the elements analyzed, including the list of eight secondary metals. Absolute differences are shown in the table to demonstrate how low metals emissions were, causing the large changes on a percent difference basis. The only statistically significant change in metals emissions was for Se.

Acid gas emissions are summarized below. Emissions of HCl and HF were considerably lower during co-firing due to the reduced level of chlorine in the fuel. The HF reduction is statistically significant using the t-test while the HCl reduction is not.

Table 3-6. Acid Gases (lb/MMBtu)

Test ID	Fuel	Hydrofluoric Acid, HF	Hydrochloric Acid, HCl
Baseline 1	100 % Coal	5.00E-03	3.94E-02
Baseline 2		5.30E-03	4.30E-02
Baseline 3		6.10E-03	4.00E-02
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	5.30E-03	3.46E-02
Cofire 2		4.50E-03	2.79E-02
Cofire 3		5.10E-03	2.95E-02
Baseline Averages		5.47E-03 ± 0.0019	4.08E-02 ± 0.0006
Cofire Averages		4.97E-03 ± 0.004	3.07E-02 ± 0.0004
Absolute Difference		-5.00E-04	-1.01E-02
% Difference		-9.15%	-28.8%
Statistically Significant Change?		Yes	No

In summary, emissions of SO_2, Se, and HF were all reduced at a level with statistical significance as a result of co-firing the wood based pellets with coal in this boiler, all without significant impacts on boiler operations or efficiency. The co-firing also resulted in a statistically significant increase in NO_X emissions.

3.3 FLYASH CHARACTERISTICS

Results of the flyash analyses are summarized in Tables 3-7 through 3-9. Changes in ash characteristics were generally small, which is favorable for most operating systems (ash handling systems would not be expected to be impacted by co-firing at this rate). Carbon content and ash loss on ignition were both reduced significantly during biomass co-firing, although neither ash met the Class F requirements for use in concrete.

Biomass co-firing during this verification did not impact the quality of the ash with regard to fly ash TCLP metals (40 CFR 261.24) and Class F Requirements (C 618-05), as shown in Tables 3-8 and 3-9. Metals content of the ash was well below the TCLP criteria during all test periods and changes were not significant. The ash generated during co-firing did have a significantly higher SO_3 content, but was still well below the Class F requirement.

Table 3-7. Ash Characteristics

Test ID	Fuel	Carbon, wt %	Silicon Dioxide, % as SiO_2	Aluminum Oxide, % as Al_2O_3	Iron Oxide, % as Fe_2O_3	Loss on Ignition	Ash Fusion Temp., °F: Reducing Atmosphere: Initial Deformation	Ash Fusion Temp., °F: Oxidizing Atmosphere: Initial Deformation
Baseline 1	100 % Coal	17.9	39.1	18.8	14.1	19.2	1,849	2,005
Baseline 2		17.2	39.0	18.4	14.9	18.6	1,900	2,051
Baseline 3		18.4	38.7	18.3	15.1	19.1	1,877	2,060
Baseline 4		16.5	38.0	17.7	15.0	18.5	1,915	2,039
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	16.5	38.3	18.0	15.0	18.3	1,860	2,075
Cofire 2		16.6	37.6	17.6	14.7	18.4	1,870	2,009
Cofire 3		15.7	38.0	17.7	15.2	17.4	2,095	2,007
Baseline Averages		17.5 ± 0.8	38.7 ± 0.5	18.3 ± 0.5	14.8 ± 0.5	18.9 ± 0.3	1,885 ± 29	2,038 ± 24
Cofire Averages		16.3 ± 0.5	37.9 ± 0.3	17.8 ± 0.2	15.0 ± 0.3	18.0 ± 0.5	1,942 ± 130	2,030 ± 39
% Difference		-6.9%	-2.0%	-3.0%	1.5%	-4.6%	3.0%	-0.40%
Statistically Significant Change?		Yes	Yes	No	No	Yes	No	No

Table 3-8. Ash TCLP Metals (mg/l)

Test ID	Fuel	Silver	Arsenic	Barium	Cadmium	Chromium	Mercury	Lead	Selenium
Baseline 1	100 % Coal	< 0.001	0.35	0.51	0.075	0.18	< 0.001	0.80	0.033
Baseline 2		< 0.001	0.25	0.47	0.086	0.18	< 0.001	0.76	0.028
Baseline 3		< 0.001	0.11	0.43	0.088	0.16	< 0.001	0.80	0.026
Baseline 4		< 0.001	0.16	0.64	0.11	0.13	< 0.001	0.60	0.021
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	< 0.001	0.29	0.64	0.110	0.19	< 0.001	1.00	0.032
Cofire 2		< 0.001	0.11	0.18	0.10	0.32	< 0.001	0.86	0.075
Cofire 3		< 0.001	0.096	0.18	0.10	0.31	< 0.001	0.66	0.067
Baseline Averages		<0.001	0.22	0.51	0.09	0.16	< 0.001	0.74	0.027
Cofire Averages		< 0.001	0.17	0.33	0.10	0.27	< 0.001	0.84	0.058
Limit / 40 CFR 261.24		5.0	5.0	100.0	1.0	5.0	0.2	5.0	1.0

Table 3-9. Fly Ash Class F Requirements (C 618-05)

Test ID	Fuel	Silicon Dioxide (SiO2) + Aluminum Oxide (Al2O3) + Iron Oxide (Fe2O3), (%)	Sulfur Trioxide (SO3), (%)	Loss on ignition, (%)
Baseline 1	100 % Coal	72.0	0.43	19.23
Baseline 2		72.3	0.46	18.64
Baseline 3		72.0	0.37	19.11
Baseline 4		70.8	0.99	18.53
Cofire 1	Blended Fuel (85.1 coal: 14.9 wood)	71.3	0.75	18.28
Cofire 2		69.9	1.14	18.36
Cofire 3		70.9	1.15	17.37
Class F Requirements		70.0 (min %)	5.0 (max %)	6.0 (max %)
Baseline Averages		71.8	0.56	18.9
Cofire Averages		70.7	1.01	18.0

3.4 SUSTAINABILITY ISSUES

Table 3-1 summarized the composition of the site's coal supply and the blended fuel. Regarding use and or disposal of fly ash, biomass co-firing did not impact either sustainability issue since the quality of the ash with regard to fly ash TCLP metals and Class F Requirements was unchanged. The following is a brief GHG sustainability analysis for use of the pelletized fuel at this site.

3.4.1 GHG Emission Offsets

Energy Used to Produce Wood-Based Pelletized Fuel

The wood pellets used for testing at the University of Iowa were produced from waste wood waste at a rate of 4.5 tons per hour. The equipment used to produce the pellets is rated at 250 horsepower and was operated at 80 percent of capacity. Based on electrical consumption of 0.746 kWh/hp multiplied by 200 hp, the energy use per hour to produce the pellets was 149.14 kWh or 33.14 kWh/ton (149.14 divided by 4.5).

CO_2 Emissions from Energy Used to Produce Wood-Based Pelletized Fuel
Based on an Energy Information Administration emission factor for Michigan (location of the production facility) of 1.58 lbs CO_2/kWh, CO_2 emissions per ton of pellets produced is 52.36 lbs (1.58 * 33.14).

Transportation Fuel Use

From Battle Creek, MI:
Wood-based pellets were transported from Battle Creek Michigan to Muscatine, Iowa (where the University of Iowa's coal supplier is located). 43 tons of wood-based pellets were shipped with two trucks using 350 Cummins motors. The trucks averaged 6.5 miles per gallon. The distance from Battle Creek to Muscatine is 345 miles. Therefore:

- 345 miles * 2 trucks = 690 miles, divided by 6.5 mpg = 106.15 gallons, divided by 43 tons fuel = 2.47 gallons/ton.

From Anamosa, IA
Renewafuel has a 28-acre site for possible future operations in Anamosa, Iowa. The distance from Anamosa to Muscatine is 65 miles. Further, Renewafuel can load as much as 25 tons of fuel per truck. Assuming use of the same truck with 6.5 miles per gallon the fuel used per ton of fuel transported from Anamosa to Muscatine, fuel usage from Anamosa is:

- 65 miles, divided by 6.5 mpg = 10 gallons, divided by 25 tons per truck = 0.4 gallons/ton

CO_2 Emissions From Transportation Fuel Use

Based on an Energy Information Administration emission factor of 19.564 lbs CO_2/gallon, CO_2 emissions per ton of pellets transported to the facility are:

- 48.3 lbs/ton for Battle Creek (2.47 gal fuel /ton pellets * 19.564 lbs CO_2/gal).
- 7.82 lbs/ton for Anamosa (0.4 gal/ton * 19.564 lbs CO_2/gal).

CO_2 Emissions from Combustion of Bituminous Coal Compared to Wood Pellets

Based on data generated during this testing, the CO_2 emission rates while firing straight coal and blended fuel (at a blending rate of approximately 15 percent wood by mass) were 205 and 207 lb/MMBtu, respectively. However, combustion of Renewafuel wood pellets, which are comprised of biogenic carbon—meaning it is part of the natural carbon balance and will not add to atmospheric concentrations of CO_2—emits no creditable CO_2 emissions under international greenhouse gas accounting methods developed by the IPCC and adopted by the CFPA [6]. By analyzing the heat content of the coal and the wood, the total boiler heat input for the test periods, and boiler efficiency, it was determined that approximately 10 percent of the heat generated during co-firing test periods is attributable to the Renewafuel pellets fuel. The following equation was used:

$$Heat_b = Fuel_t * 0.149 * (LHV_b/1000000)$$

Where:
$Heat_b$ = average heat input attributable to wood pellets (27.7 MMBtu/hr)
$Fuel_t$ = average fuel feed rate (24,200 lb/hr), from plant records
0.149 = coal : biomass ratio, determined at coal yard
LHV_b = heat content of wood pellets (7,688 Btu/lb), from fuel sample analyses
1,000,000 = Btu/MMBtu

It is therefore estimated that the CO_2 emissions offset during this testing is approximately 10 percent, or 20.7 lb/MMBtu at this co-firing blend.

UI Boiler 10 typically operates in the 160 to 190 MMBtu/hr heat generating rate. Assuming an availability and utilization rate of 80 percent for Boiler 10, this would equate to estimated annual CO_2 emission reductions of approximately 11,000 to 13,000 tons per year. CO_2 offsets from use of wood pellets could be even greater had the analysis included emissions associated with coal mining and transportation.

The following equation was used:

$$CO2_{offset\text{-}annual} = CO2_{offset} * Gen_{rate} * Av * 8{,}765 * (1/2{,}000)$$

Where: $CO2_{offset\text{-}annual}$ = annual CO_2 offset (13,648 ton/yr)
$CO2_{offset}$ = CO2 emissions offset (20.7 lb/MMBtu)
Gen_{rate} = average boiler generating rate (190 MMBtu/hr)
Av = Assumed availability for boiler 10 (80 percent)
8,765 = hours per year
2,000 = lbs per ton

4.0 DATA QUALITY ASSESSMENT

4.1 DATA QUALITY OBJECTIVES

Under the ETV-ESTE program, Southern specifies data quality objectives (DQOs) for each primary verification parameter before testing commences as a statement of data quality. The DQOs for this verification were developed based on input from EPA's ETV QA reviewers, and input from the BCSG. Test results which meet the DQOs provide an acceptable level of data quality for technology users and decision makers.

The DQOs for this verification are qualitative in that the verification produced emissions performance data that satisfy the QC requirements contained in the EPA Reference Methods specified for each pollutant, and the fuel and fly ash analyses meet the quality assurance / quality control (QA/QC) requirements contained in the ASTM Methods being used.

This verification did not include a stated DQO for boiler efficiency determinations because measurement accuracy validation for certain boiler parameters was not possible. Section 4.1.3 provides further discussion.

4.1.1 Emissions Testing QA/QC Checks

Each of the EPA Reference Methods used here for emissions testing contains rigorous and detailed calibrations, performance criteria, and other types of QA/QC checks. For instrumental methods using gas analyzers, these performance criteria include analyzer span, calibration error, sampling system bias, zero drift, response time, interference response, and calibration drift requirements. Methods 5, 29, CTM040, and 202 for determination of particulates and metals also include detailed performance requirements and QA/QC checks. Details regarding each of these checks can be found in the methods and are not repeated here. However, results of certain key QA/QC checks for each method are reported as documentation that the methods were properly executed. Key emissions testing QA/QC checks are summarized in Table 4-1. Where facility CEMS were used, up to date relative accuracy test audit (RATA) certifications and quarterly cylinder gas audits (CGAs) have been procured, reviewed, and filed at Southern to document system accuracy.

The emissions testing completeness goal for this verification was to obtain valid data for 90 percent of the test periods on each boiler tested. This goal was achieved as all data was validated for the test periods except for the third baseline test run. Test personnel conducted a fourth test run in response.

Table 4-1. Summary of Emission Testing Calibrations and QA/QC Checks

Parameter	Calibration/QC Check	When Performed/Frequency	Allowable Result	Actual Result
NO_X, CO, CO_2, O_2	Analyzer calibration error test	Daily before testing	± 2 % of analyzer span	All calibrations, system bias checks, and drift tests were within the allowable criteria.
	System bias checks	Before each test run	± 5 % of analyzer span	
	System calibration drift test	After each test run	± 3 % of analyzer span	
SO_2	Relative accuracy test audit	annually	± 20 percent of reference method	Relative accuracy was 5.2 percent (February 2007)
NO_X	NO_2 converter efficiency	Once before testing begins	98 % minimum	NO_X converter efficiency was over 99%.
TPM, Metals	Percent isokinetic rate	After each test run	90 - 110 % for TPM and metals	All criteria were met for the TPM and metals measurement and analytical systems.
	Analytical balance calibration	Daily before analyses	± 0.0002 g	
	Filter and reagent blanks	Once during testing after first test run	< 10 % of particulate catch for first test run	
	Sampling system leak test	After each test	<0.02 cfm	
	Dry gas meter calibration	Once before and once after testing	± 5 %	
	Sampling nozzle calibration	Once for each nozzle before testing	± 0.01 in.	
Metals	ICP/CVAAS	Spike and recovery of prepared QC standards	± 25% of expected value	All matrix spike and recovery results were within 90 to 110 percent of the standards, including an independent Hg audit sample
HCl, HF	Sampling system leak test	After each test	<0.02 cfm	All criteria were met for the acid gases measurement and analytical systems.
	Dry gas meter calibration	Once before and once after testing	± 5 %	
	Ion chromatograph	Analysis of prepared QC standards	± 10% of expected value	

4.1.2 Fly ash and Fuel Analyses QA/QC Checks

The laboratory selected for analysis of collected fuel and fly ash samples (Wyoming Analytical Laboratory Services, Inc.) operates under an internal quality assurance protocol, a copy of which is maintained at Southern. Each of the analytical procedures used here include detailed procedures for instrument calibration and sample handling. They also include QA/QC checks in the form of analytical repeatability requirements or matrix spike analyses. All of the QA/QC checks specified in the methods were met during these analyses.

4.1.3 Boiler Efficiency QA/QC Checks

Table 4-2 summarizes the contributing measurements for boiler efficiency determination, measurement quality objectives (MQOs) for each, and the primary method of evaluating the MQOs. Factory calibrations, sensor function checks, and reasonableness checks in the field were used to assess achievement of the MQOs where possible. Some of the MQOs were either not met or impossible to verify, so the overall uncertainty of the boiler efficiency determinations is unclear. In anticipation of this, the test plan did not specify a DQO for boiler efficiency.

Table 4-2. Boiler Efficiency QA/QC Checks

Measurement / Instrument	QA/QC Check	When Performed	MQO	Results achieved
Fuel temperature, °F	NIST-traceable calibration	Upon purchase and every 2 years	± 6 °F	Fuel temp ± 1°F Flue gas temp ± 5°F
Flue gas temperature at air heater inlet, °F				
Air temperature, °F	NIST-traceable calibration		± 1 °F	± 1°F
Moisture in air, lb/lb dry air	NIST-traceable calibration		± 3.5 %	± 3.0 %
Combustion air temperature, °F	Cross check with NIST-traceable standard	Annually	± 6 °F	Within 5°F
Steam flow, MMBtu/h or lb/h	Orifice calibration	Upon installation	± 5 % reading	Calibration not available
Steam pressure, psig	Cross check with NIST-traceable standard	Annually	± 5 psig	± 6 psig
Steam temperature, °F			± 6 °F	± 10 °F
Supply water pressure, psig			± 5 psig	Calibrations not available
Supply water temperature, °F			± 2 % of reference standard	
Fuel feed rate, lb/h	Cross check with boiler efficiency calculations	Annually	± 5 % reading	Average ± 11%, but not used for determining efficiency
Fuel ultimate analyses, both wood and coal	ASTM D1945 duplicate sample analysis and repeatability	2 samples	Within D1945 repeatability limits for each fuel component	Method repeatability criteria were met
Fuel heating value, Btu/lb	ASTM D1945 duplicate sample analysis and repeatability		Within D1945 repeatability limits for each fuel component	

5.0 REFERENCES

[1] Southern Research Institute, *Test and Quality Assurance Plan – Environmental and Sustainable Technology Evaluation – Biomass Co-firing in Industrial Boilers,* www.sri-rtp.com, Southern Research Institute, Research Triangle Park, NC. October 2006.

[2] Babcock & Wilcox, *Steam –Its Generation and Use – 40th Edition,* The Babcock & Wilcox Company, Barberton, Ohio, 1992.

[3] Code of Federal Regulations (Title 40 Part 60, Appendix A) *Test Methods (Various)*, http://www.gpoaccess.gov/cfr/index.html, U.S. Environmental Protection Agency, Washington, DC, 2005.

[4] U.S. EPA, *AP-42, Compilation of Air Pollutant Emission Factors, http://www.epa.gov/oms/ap42.htm,* U.S. Environmental Protection Agency Office of Transportation and Air Quality, Washington D.C., 2005.

[5] Code of Federal Regulations (Title 40 Part 261.24) *Identification and Listing of Hazardous Waste – Toxicity Characteristic*, http://www.access.gpo.gov/nara/cfr/waisidx_05/40cfr261_05.html, U.S. Environmental Protection Agency, Washington, DC, 2005.

[6] The Climate Change Working Group of The International Council of Forest and Paper Associations (ICFPA) *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.1,* National Council for Air and Stream Improvement, Inc. (NCASI), Research Triangle Park, NC, July, 2005.

Appendix A
Unit 10 Emissions Data

GE Energy

PARTICULATE TEST RESULTS SUMMARY

Company: University of Iowa
Plant: Main Power Plant
Unit: Boiler 10 Outlet Duct

Test Run Number	**1**	**2**	**3**	**Average**
Source Condition	Coal Only	Coal Only	Coal Only	
Date	3/13/2007	3/13/2007	3/13/2007	
Start Time	8:25	12:12	15:30	
End Time	11:11	14:52	18:00	
Total Particulate:				
grains/dscf	0.0426	0.0188	0.0259	0.0291
lb/hr	18.434	8.445	11.501	12.793
lb/mmBtu (Fd = 9746)	0.0892	0.0391	0.0534	0.0606
Filterable PM:				
grains/dscf	0.0182	0.0112	0.0151	0.0148
lb/hr	7.873	5.018	6.699	6.530
lb/mmBtu (Fd = 9746)	0.0381	0.0232	0.0311	0.0308
Condensible PM (Method 202):				
grains/dscf	0.0244	0.0076	0.0108	0.0143
lb/hr	10.561	3.427	4.802	6.263
lb/mmBtu (Fd = 9746)	0.0511	0.0159	0.0223	0.0298
Stack Parameters:				
Gas Volumetric Flow Rate, acfm	86,169	88,443	88,768	87,793
Gas Volumetric Flow Rate, dscfm	50,484	52,428	51,832	51,581
Average Gas Temperature, °F	347.4	348.6	347.7	347.9
Average Gas Velocity, ft/sec	47.636	48.893	49.073	48.534
Flue Gas Moisture, percent by volume	7.8	6.5	8.0	7.4
Average Flue Pressure, in. Hg	29.06	29.06	29.06	
Barometric Pressure, in. Hg	29.15	29.15	29.15	
Average $\%CO_2$ by volume, dry basis	12.4	12.4	12.5	12.4
Average $\%O_2$ by volume, dry basis	7.0	6.9	6.8	6.9
Dry Molecular Wt. of Gas, lb/lb-mole	30.264	30.260	30.272	
Gas Sample Volume, dscf	94.896	95.904	95.071	
Isokinetic Variance	104.3	101.5	101.8	

GE Energy

University of Iowa
Main Power Plant - Boiler 10 Outlet Duct
Average Metals Results
Tests 1 through 4 - Coal Only
March 13 and 15, 2007

Parameter	Concentration (lbs/dscf)	Emissions Rate (lbs/hr)	gr/dscf	gr/acf	lbs/MMBtu (using calculated fuel factor)	ug/Nm^3
Arsenic	8.37E-10	2.77E-03	5.86E-06	3.42E-06	1.22E-05	13.415
Barium	2.82E-10	9.35E-04	1.97E-06	1.15E-06	4.14E-06	4.518
Beryllium	2.05E-11	6.82E-05	1.44E-07	8.39E-08	3.01E-07	0.329
Cadmium	3.79E-11	1.25E-04	2.65E-07	1.54E-07	5.55E-07	0.607
Chromium	1.20E-09	4.07E-03	8.40E-06	4.95E-06	1.78E-05	19.213
Copper	2.59E-10	8.67E-04	1.81E-06	1.06E-06	3.81E-06	4.152
Lead	3.61E-10	1.19E-03	2.53E-06	1.47E-06	5.26E-06	5.787
Manganese	1.10E-09	3.76E-03	7.68E-06	4.54E-06	1.63E-05	17.566
Mercury	< 2.37E-10	< 7.73E-04	< 1.66E-06	< 9.62E-07	< 3.45E-06	< 3.796
Nickel	1.87E-09	6.40E-03	1.31E-05	7.73E-06	2.78E-05	29.889
Selenium	4.42E-09	1.47E-02	3.10E-05	1.81E-05	6.48E-05	70.854
Silver	4.22E-11	1.40E-04	2.95E-07	1.73E-07	6.19E-07	0.676
Zinc	1.55E-09	5.11E-03	1.08E-05	6.31E-06	2.26E-05	24.765

Test Support Data	
Volumetric Flowrate (acfm)	94,641
Volumetric Flowrate (dscfm)	55,247
%O2	7.0
%CO2	12.3
Calculated Fuel Factor	9,746

GE Energy

HYDROGEN CHLORIDE/HYDROGEN FLUORIDE TEST RESULTS SUMMARY

University of Iowa
Main Power Plant
Boiler 10 Outlet Duct
Coal Only
March 13, 2007

RUN #	Time	CO_2 % dry	O_2 % dry	Flow dscfm	HCl ppm	HCl lbs/hr	HCl lbs/MMBtu
1	08:57-09:57	12.4	7.0	50,484	28.405	8.148	0.039
2	12:50-13:50	12.4	6.9	52,428	31.209	9.297	0.043
3	15:30-16:30	12.5	6.8	51,832	29.236	8.611	0.040
Average		12.4	6.9	51,581	29.617	8.685	0.041

RUN #	Time	HF ppm	HF lbs/hr	HF lbs/MMBtu
1	08:57-09:57	6.598	1.039	0.005
2	12:50-13:50	6.952	1.136	0.005
3	15:30-16:30	8.099	1.309	0.006
Average		7.216	1.161	0.006

Fuel factor = 9746 dscf/MMBtu

GE Energy

GASEOUS TEST RESULTS SUMMARY

University of Iowa
Main Power Plant
Boiler 10 Outlet Duct
Coal Only
March 13 and 15, 2007

Run #	Time	Flow dscfm	O_2 % dry	CO_2 % dry	NO_x		
					ppmvd	lbs/MMBtu	lbs/hr
1	08:25-11:11	50,484	7.0	12.4	270.5	0.473	97.83
2	12:11-14:52	52,428	6.9	12.4	254.3	0.442	95.51
3	15:30-18:00	51,832	6.8	12.5	253.8	0.438	94.24
Average		51,581	6.9	12.4	259.5	0.451	95.86
4	07:50-10:10	57,861	7.3	12.0	276.4	0.486	114.57

Run #	Time	CO		
		ppmvd	lbs/MMBtu	lbs/hr
1	08:25-11:11	76.2	0.081	16.78
2	12:11-14:52	78.5	0.083	17.93
3	15:30-18:00	81.0	0.085	18.30
Average		78.6	0.083	17.67
4	07:50-10:10	95.3	0.102	24.03

March 13 Fuel factor = 9746 dscf/MMBtu
March 15 Fuel factor = 9584 dscf/MMBtu

Note: The flow dscfm values for runs 1 through 3 were taken from the particulate results. The flow dscfm value for run 4 was taken from the metal results.

GE Energy

PARTICULATE TEST RESULTS SUMMARY

Company: University of Iowa
Plant: Main Power Plant
Unit: Boiler 10 Outlet Duct

Test Run Number	1	2	3	Average
Source Condition	75% Coal / 25% Wood	75% Coal / 25% Wood	75% Coal / 25% Wood	
Date	3/14/2007	3/14/2007	3/14/2007	
Start Time	8:20	11:50	15:10	
End Time	11:00	14:23	17:35	
Total Particulate:				
grains/dscf	0.0221	0.0211	0.0200	0.0210
lb/hr	10.554	9.665	9.380	9.866
lb/mmBtu (Fd = 9648)	0.0464	0.0435	0.0411	0.0436
Filterable PM:				
grains/dscf	0.0123	0.0112	0.0110	0.0115
lb/hr	5.891	5.143	5.170	5.402
lb/mmBtu (Fd = 9648)	0.0259	0.0231	0.0226	0.0239
Condensible PM (Method 202):				
grains/dscf	0.0097	0.0099	0.0090	0.0095
lb/hr	4.662	4.521	4.210	4.465
lb/mmBtu (Fd = 9648)	0.0205	0.0203	0.0184	0.0198
Stack Parameters:				
Gas Volumetric Flow Rate, acfm	95,517	92,261	94,020	93,933
Gas Volumetric Flow Rate, dscfm	55,795	53,385	54,851	54,677
Average Gas Temperature, °F	351.1	352.8	351.8	351.9
Average Gas Velocity, ft/sec	52.804	51.004	51.976	51.928
Flue Gas Moisture, percent by volume	7.8	8.5	7.9	8.1
Average Flue Pressure, in. Hg	29.13	29.13	29.13	
Barometric Pressure, in. Hg	29.20	29.20	29.20	
Average %CO_2 by volume, dry basis	12.3	12.6	12.6	12.5
Average %O_2 by volume, dry basis	7.2	6.9	6.9	7.0
Dry Molecular Wt. of Gas, lb/lb-mole	30.256	30.292	30.292	
Gas Sample Volume, dscf	104.464	101.033	95.281	
Isokinetic Variance	103.9	105.1	96.4	

GE Energy

University of Iowa
Main Power Plant - Boiler 10 Outlet Duct
Average Metals Results
Tests 1 through 3 - 75% Coal/25% Wood
March 14, 2007

Parameter	Concentration (lbs/dscf)	Emissions Rate (lbs/hr)	gr/dscf	gr/acf	lbs/MMBtu (using calculated fuel factor)	ug/Nm^3
Arsenic	5.42E-10	1.87E-03	3.79E-06	2.21E-06	7.87E-06	8.674
Barium	1.87E-10	6.43E-04	1.31E-06	7.62E-07	2.71E-06	2.996
Beryllium	2.17E-11	7.49E-05	1.52E-07	8.85E-08	3.15E-07	0.348
Cadmium	3.16E-11	1.09E-04	2.21E-07	1.29E-07	4.58E-07	0.506
Chromium	7.47E-09	2.63E-02	5.23E-05	3.05E-05	1.10E-04	119.658
Copper	3.28E-10	1.15E-03	2.29E-06	1.34E-06	4.80E-06	5.247
Lead	1.70E-10	5.87E-04	1.19E-06	6.90E-07	2.46E-06	2.715
Manganese	1.13E-09	3.92E-03	7.89E-06	4.59E-06	1.64E-05	18.045
Mercury	2.72E-10	9.37E-04	1.90E-06	1.11E-06	3.94E-06	4.353
Nickel	3.95E-09	1.39E-02	2.77E-05	1.61E-05	5.81E-05	63.310
Selenium	2.99E-09	1.03E-02	2.09E-05	1.22E-05	4.34E-05	47.835
Silver	4.34E-11	1.50E-04	3.04E-07	1.77E-07	6.30E-07	0.696
Zinc	1.35E-09	4.70E-03	9.44E-06	5.49E-06	1.83E-05	21.609

Test Support Data	
Volumetric Flowrate (acfm)	98,755
Volumetric Flowrate (dscfm)	57,455
%O2	7.0
%CO2	12.5
Calculated Fuel Factor	9,648

GE Energy

HYDROGEN CHLORIDE/HYDROGEN FLUORIDE TEST RESULTS SUMMARY

University of Iowa
Main Power Plant
Boiler 10 Outlet Duct
75% Coal/25% Wood
March 14, 2007

RUN #	Time	CO_2 % dry	O_2 % dry	Flow dscfm	HCl ppm	HCl lbs/hr	HCl lbs/MMBtu
1	08:20-09:20	12.3	7.2	55,795	24.848	7.878	0.035
2	11:50-12:50	12.6	6.9	53,385	20.451	6.204	0.028
3	15:10-16:10	12.6	6.9	54,851	21.655	6.749	0.030
Average		12.5	7.0	54,677	22.318	6.944	0.031

RUN #	Time	HF ppm	HF lbs/hr	HF lbs/MMBtu
1	08:20-09:20	6.944	1.208	0.005
2	11:50-12:50	6.005	0.999	0.005
3	15:10-16:10	6.855	1.172	0.005
Average		6.601	1.127	0.005

Fuel factor = 9648 dscf/MMBtu

GE Energy

GASEOUS TEST RESULTS SUMMARY

University of Iowa
Main Power Plant
Boiler 10 Outlet Duct
75% Coal/25% Wood
March 14, 2007

Run #	Time	Flow dscfm	O_2 % dry	CO_2 % dry	NO_x		
					ppmvd	lbs/MMBtu	lbs/hr
1	08:20-11:00	55,795	7.2	12.3	277.4	0.487	110.88
2	11:50-14:23	53,385	6.9	12.6	305.5	0.525	116.84
3	15:10-17:35	54,851	6.9	12.6	294.4	0.506	115.69
Average		54,677	7.0	12.5	292.4	0.506	114.47

Run #	Time	CO		
		ppmvd	lbs/MMBtu	lbs/hr
1	08:20-11:00	83.0	0.089	20.19
2	11:50-14:23	77.1	0.081	17.95
3	15:10-17:35	77.1	0.081	18.43
Average		79.1	0.084	18.86

Fuel factor (75% Coal/25% Wood) = 9648 dscf/MMBtu

Appendix B

Fuel and Ash Analyses

Fuel samples labeled as 3-13-07 represent baseline results, and fuel samples labeled 3-14-07 represent co-fired fuel results. Ash samples labeled as Runs 1 through 3 represent samples collected while firing straight coal, and samples labeled as Runs 4 though 7 represent samples while co-firing.

Kelley to insert pdf files in final report

Appendix C

Boiler Efficiency Determinations

University of Iowa Testing: Day 1, Coal only, Run #1 03/13/2007

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION			FUEL - Subbituminous Coal, Iowa					
			15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
				Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
1	Excess air: at burner/leaving boiler/econ, % by weight	38.5							
2	Entering air temperature, F	58.34							
3	Reference temperature, F	80	A	C	63.77	11.51	734.0		
4	Fuel temperature, F	70.6	B	S	1.48	4.32	6.4		
5	Air temperature leaving air heater, F	246.87	C	H_2	4.37	34.29	149.8	8.94	39.07
6	Flue gas temperature leaving (excluding leakage), F	371.51	D	H_2O	13.76			1.00	13.76
7	Moisture in air, lb/lb dry air	0.0078	E	N_2	1.45				
8	Additional moisture, lb/100 lb fuel	0	F	O_2	8.16	-4.32	-35.3		
9	Residue leaving boiler/economizer, % Total	85	G	Ash	7.01				
10	Output, 1,000,000 Btu/h (MMBtu/h)	224.40	H	Total	100.00	Air	855.0	H_2O	52.83

11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0	18	Higher heating value (HHV), Btu/lb fuel		11,242
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0	19	Unburned carbon loss, % fuel input		0.28
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0	20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.605
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0	21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.22

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]				7.583
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]				0.064
24	Total residue, lb/10,000 Btu	[23] + [14]				0.064
		A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ
25	Excess air, % by weight	38.5	0.0		38.5	38.5

			C Leaving Furnace		D Leaving Blr/Econ	
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]		10.504		10.504
27	H_2O from air, lb/10,000 Btu	[26] x [7]	0.082	0.082	0.082	0.082
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]	0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]	0.470		0.470	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]		0.825		0.825
31	CO_2 from sorbent, lb/10,000 Btu	[12]		0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]	0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]		11.411		11.411
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]	0.552	0.552	0.552	0.552
35	Dry gas, lb/10,000 Btu	[33] - [34]		10.860		10.860
36	H_2O in gas, % in weight	100 x [34] / [33]		4.84		4.84
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]		0.48		0.48

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses				
38	Dry Gas, %		0.0024 [35D] x ([6] - [3])		7.60
39	Water from	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1228.5	
40	fuel, as fired	Enthalpy of water at T = [3]	H2 = [3] -32	48.0	
41	%		[29] x ([39] - [40]) / 100		5.55
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])		0.11
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]		0.28
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h	0.70
45	Other, % (include manufacturers margin if applicable)				1.50
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]		0.00
47	Summation of losses, %		Summation [38] through [46]		15.73
	Credits				
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])		-0.55
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])		-0.01
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01 H @ 80 ~ 1.0	0.01
51	Other, %				0.00
52	Summation of credits, %		Summation [48] through [51]		-0.55
53	**Efficiency, %**		100 - [47] - [52]		**84.81**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		264.6
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		23.5
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	301.9	301.9
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	10.586	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	280.1	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha (Btu/lb) 41.37	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	260.5	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	862.6	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3020.0	

University of Iowa Testing: Day 1, Coal only, Run #2 03/13/2007

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION			FUEL - Subbituminous Coal, Iowa					
1	Excess air: at burner/leaving boiler/econ, % by weight	38.6	15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
2	Entering air temperature, F	69.83		Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
3	Reference temperature, F	80	A	C	63.73	11.51	733.5		
4	Fuel temperature, F	71	B	S	1.50	4.32	6.5		
5	Air temperature leaving air heater, F	249.29	C	H_2	4.19	34.29	143.7	8.94	37.46
6	Flue gas temperature leaving (excluding leakage), F	372.92	D	H_2O	13.87			1.00	13.87
7	Moisture in air, lb/lb dry air	0.0077	E	N_2	1.31				
8	Additional moisture, lb/100 lb fuel	0	F	O_2	8.71	-4.32	-37.6		
9	Residue leaving boiler/economizer, % Total	85	G	Ash	6.69				
10	Output, 1,000,000 Btu/h (MMBtu/h)	223.90	H	Total	100.00	Air	846.1	H_2O	51.33

11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0	18	Higher heating value (HHV), Btu/lb fuel		11,287
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0	19	Unburned carbon loss, % fuel input		0.27
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0	20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.496
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0	21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.21

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]				7.474
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]				0.061
24	Total residue, lb/10,000 Btu	[23] + [14]				0.061
		A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ
25	Excess air, % by weight	38.6	0.0	38.6		38.6

			C	C	D	D
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]		10.359		10.359
27	H_2O from air, lb/10,000 Btu	[26] x [7]	0.080	0.080	0.080	0.080
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]	0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]	0.455		0.455	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]		0.825		0.825
31	CO_2 from sorbent, lb/10,000 Btu	[12]		0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]	0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]		11.263		11.263
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]	0.535	0.535	0.535	0.535
35	Dry gas, lb/10,000 Btu	[33] - [34]		10.729		10.729
36	H_2O in gas, % in weight	100 x [34] / [33]		4.75		4.75
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]		0.46		0.46

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses				
38	Dry Gas, %		0.0024 x [35d] x ([6] - [3])		7.54
39	Water from	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1229.1	
40	fuel, as fired	Enthalpy of water at T = [3]	H2 = [3] -32	48.0	
41	%		[29] x ([39] - [40]) / 100		5.37
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])		0.11
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]		0.27
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h	0.70
45	Other, % (include manufacturers margin if applicable)				1.50
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]		0.00
47	Summation of losses, %		Summation [38] through [46]		15.49
	Credits				
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])		-0.25
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])		0.00
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01 H @ 80 ~ 1.0	0.01
51	Other, %				0.00
52	Summation of credits, %		Summation [48] through [51]		-0.25
53	**Efficiency, %**		100 - [47] - [52]		**84.76**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		264.2
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		23.4
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	297.5	297.5
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	10.439	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	275.7	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha (Btu/lb) 41.97	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	260.5	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	875.4	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3055.0	

University of Iowa Testing: Day 1, Coal only, Run #3 03/13/2007

Combustion Calculations - Btu Method

#	INPUT CONDITIONS - BY TEST OR SPECIFICATION			FUEL - Subbituminous Coal, Iowa					
1	Excess air: at burner/leaving boiler/econ, % by weight	37.9	15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
2	Entering air temperature, F	74.35		Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
3	Reference temperature, F	80	A	C	61.82	11.51	711.5		
4	Fuel temperature, F	74.8	B	S	1.05	4.32	4.5		
5	Air temperature leaving air heater, F	249.86	C	H_2	4.20	34.29	144.0	8.94	37.55
6	Flue gas temperature leaving (excluding leakage), F	372.753	D	H_2O	14.39			1.00	14.39
7	Moisture in air, lb/lb dry air	0.0082	E	N_2	1.20				
8	Additional moisture, lb/100 lb fuel	0	F	O_2	10.95	-4.32	-47.3		
9	Residue leaving boiler/economizer, % Total	85	G	Ash	6.39				
10	Output, 1,000,000 Btu/h (MMBtu/h)	223.71	H	Total	100.00	Air	812.8	H2O	51.94

11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0	18	Higher heating value (HHV), Btu/lb fuel		10,935
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0	19	Unburned carbon loss, % fuel input		0.30
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0	20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.433
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0	21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.22

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

			A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						7.409
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.060
24	Total residue, lb/10,000 Btu	[23] + [14]						0.060
25	Excess air, % by weight		37.9	0.0		37.9		37.9
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				10.218		10.218
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.084	0.084	0.084	0.084
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.475		0.475	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				0.854		0.854
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				11.155		11.155
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.559	0.559	0.559	0.559
35	Dry gas, lb/10,000 Btu	[33] - [34]				10.597		10.597
36	H_2O in gas, % in weight	100 x [34] / [33]				5.01		5.01
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.46		0.46

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses					
38	Dry Gas, %		0.0024 x [35d] x ([6] - [3])			7.45
39	Water from	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1229.1		
40	fuel, as fired	Enthalpy of water at T = [3]	H2 = [3] -32	48.0		
41	%		[29] x ([39] - [40]) / 100			5.61
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])			0.11
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]			0.30
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h		0.70
45	Other, % (include manufacturers margin if applicable)					1.50
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]			0.00
47	Summation of losses, %		Summation [38] through [46]			15.66
	Credits					
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])			-0.14
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])			0.00
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01	H @ 80 ~ 1.0	0.01
51	Other, %					0.00
52	Summation of credits, %		Summation [48] through [51]			-0.13
53	**Efficiency, %**		100 - [47] - [52]			**84.47**

	KEY PERFORMANCE PARAMETERS		Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		264.8
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		24.2
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	295.4	295.4
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	10.301	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	272.8	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha (Btu/lb) 42.11	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	260.5	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	881.6	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	3063.0	

University of Iowa Testing: Day 3, Coal only, Run #7 03/15/2007

Combustion Calculations - Btu Method

INPUT CONDITIONS - BY TEST OR SPECIFICATION

1	Excess air: at burner/leaving boiler/econ, % by weight	41.1
2	Entering air temperature, F	42.09
3	Reference temperature, F	80
4	Fuel temperature, F	69
5	Air temperature leaving air heater, F	233.95
6	Flue gas temperature leaving (excluding leakage), F	372.14
7	Moisture in air, lb/lb dry air	0.0033
8	Additional moisture, lb/100 lb fuel	0
9	Residue leaving boiler/economizer, % Total	85
10	Output, 1,000,000 Btu/h (MMBtu/h)	228.83
11	Additional theoretical air, lb/10,000 Btu Table 14, Item [2	0
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0

FUEL - Subbituminous Coal, Iowa

15	Ultimate Analysis		16	Theo Air, lb/100 lb fuel	17	H_2O, lb/100 lb fuel
	Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
A	C	62.27	11.51	716.7		
B	S	1.48	4.32	6.4		
C	H_2	4.14	34.29	142.0	8.94	37.01
D	H_2O	13.84			1.00	13.84
E	N_2	1.24				
F	O_2	9.76	-4.32	-42.2		
G	Ash	7.27				
H	Total	100.00	Air	822.9	H_2O	50.85

18	Higher heating value (HHV), Btu/lb fuel		11,153
19	Unburned carbon loss, % fuel input		0.27
20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.378
21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.20

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]	7.357
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]	0.067
24	Total residue, lb/10,000 Btu	[23] + [14]	0.067

		A At Burners	B Infiltration	C Leaving Furnace	D Leaving Blr/Econ
25	Excess air, % by weight	41.1	0.0	41.1	41.1

			C Leaving Furnace		D Leaving Blr/Econ	
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]		10.383		10.383
27	H_2O from air, lb/10,000 Btu	[26] x [7]	0.034	0.034	0.034	0.034
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]	0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]	0.456		0.456	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]		0.830		0.830
31	CO_2 from sorbent, lb/10,000 Btu	[12]		0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]	0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]		11.247		11.247
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]	0.490	0.490	0.490	0.490
35	Dry gas, lb/10,000 Btu	[33] - [34]		10.757		10.757
36	H_2O in gas, % in weight	100 x [34] / [33]		4.36		4.36
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]		0.51		0.51

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses			
38	Dry Gas, %	0.0024 [35D] x ([6] - [3])		7.54
39	Water from fuel, as fired % — Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1228.8	
40	Enthalpy of water at T = [3]	H2 = [3] -32	48.0	
41		[29] x ([39] - [40]) / 100		5.38
42	Moisture in air, %	0.0045 x [27D] x ([6] - [3])		0.05
43	Unburned carbon, %	[19] or [21] x 14,500 / [18]		0.27
44	Radiation and convection, %	ABMA curve, Chapter 23	based on output of plant Btu/h	0.70
45	Other, % (include manufacturers margin if applicable)			1.50
46	Sorbent net losses, % if sorbent is used	From Chapter 10, Table 14, Item [41]		0.00
47	Summation of losses, %	Summation [38] through [46]		15.44
	Credits			
48	Heat in dry air, %	0.0024 x [26D] x ([2] - [3])		-0.94
49	Heat in moisture in air, %	0.0045 x [27D] x ([2] - [3])		-0.01
50	Sensible heat in fuel, %	(H at T[4] - H at T[3]) x 100 / [18]	0.01 H @ 80 ~ 1.0	0.01
51	Other, %			0.00
52	Summation of credits, %	Summation [48] through [51]		-0.94
53	**Efficiency, %**	100 - [47] - [52]		**85.51**

KEY PERFORMANCE PARAMETERS

			Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		267.6
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		24.0
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	301.0	301.0
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	10.417	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	278.8	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha (Btu/lb) 38.21	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	262.8	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	873.0	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	2925.0	

University of Iowa Testing: Day 2, Biomass and Coal Mix, Run #4 03/14/2007

Combustion Calculations - Btu Method

	INPUT CONDITIONS - BY TEST OR SPECIFICATION			FUEL - Biomass, Iowa					
1	Excess air: at burner/leaving boiler/econ, % by weight	41.7	15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
2	Entering air temperature, F	53.71		Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
3	Reference temperature, F	80	A	C	59.83	11.51	688.6		
4	Fuel temperature, F	70.667	B	S	1.40	4.32	6.0		
5	Air temperature leaving air heater, F	242.99	C	H_2	4.54	34.29	155.7	8.94	40.59
6	Flue gas temperature leaving (excluding leakage), F	375.45	D	H_2O	13.59			1.00	13.59
7	Moisture in air, lb/lb dry air	0.0056	E	N_2	1.23				
8	Additional moisture, lb/100 lb fuel	0	F	O_2	12.77	-4.32	-55.2		
9	Residue leaving boiler/economizer, % Total	85	G	Ash	6.64				
10	Output, 1,000,000 Btu/h	229.68	H	Total	100.00	Air	795.2	H2O	54.18

11	Additional theoretical air, lb/10,000 Btu Table 14, Item [21]	0	18	Higher heating value (HHV), Btu/lb fuel		10,615
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0	19	Unburned carbon loss, % fuel input		0.28
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0	20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.491
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0	21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.20

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						7.469
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.064
24	Total residue, lb/10,000 Btu	[23] + [14]						0.064
			A At Burners	B Infiltration	C	Leaving Furnace	D	Leaving Blr/Econ
25	Excess air, % by weight		41.7	0.0		41.7		41.7
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				10.584		10.584
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.059	0.059	0.059	0.059
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.510		0.510	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				0.878		0.878
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				11.521		11.521
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.570	0.570	0.570	0.570
35	Dry gas, lb/10,000 Btu	[33] - [34]				10.951		10.951
36	H_2O in gas, % in weight	100 x [34] / [33]				4.94		4.94
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.48		0.48

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses					
38	Dry Gas, %		0.0024 x [35d] x ([6] - [3])			7.77
39	Water from	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2		1230.3	
40	fuel, as fired	Enthalpy of water at T = [3]	H2 = [3] -32		48.0	
41	%		[29] x ([39] - [40]) / 100			6.03
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])			0.08
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]			0.28
44	Radiation and convection, %		ABMA curve, Chapter 23		based on output of plant Btu/h	1.70
45	Other, % (include manufacturers margin if applicable)					1.50
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]			0.00
47	Summation of losses, %		Summation [38] through [46]			17.35
	Credits					
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])			-0.67
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])			-0.01
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01	H @ 80 ~ 1.0	0.01
51	Other, %					0.00
52	Summation of credits, %		Summation [48] through [51]			-0.67
53	**Efficiency, %**		100 - [47] - [52]			**83.31**

	KEY PERFORMANCE PARAMETERS			Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h		100 x [10] / [53]		275.7
55	Fuel rate, 1000 lb/h		1000 x [54] / [18]		26.0
56	Wet gas weight, 1000 lb/h		[54] x [33] / 10	317.6	317.6
57	Air to burners (wet), lb/10,000 Btu		(1 +[7]) x (1 + [25A] / 100) x [22]	10.644	
58	Air to burners (wet), 1000 lb/h		[54] x [57] / 10	293.4	
59	Heat available, 1,000,000 Btu/h		[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha (Btu/lb)	40.42	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	268.6	
60	Heat available/lb wet gas, Btu/lb		1000 x [59] / [56]	845.8	
61	Adiabatic flame temperature, F		From Chapter 10, Fig.3 at H = [60], % H2O = [36]	2205.0	

University of Iowa Testing: Day 2, Biomass and Coal Mix, Run #5 03/14/2007

Combustion Calculations - Btu Method

INPUT CONDITIONS - BY TEST OR SPECIFICATION

1	Excess air: at burner/leaving boiler/econ, % by weight	39.2
2	Entering air temperature, F	61.82
3	Reference temperature, F	80
4	Fuel temperature, F	71.25
5	Air temperature leaving air heater, F	246.97
6	Flue gas temperature leaving (excluding leakage), F	377.23
7	Moisture in air, lb/lb dry air	0.0049
8	Additional moisture, lb/100 lb fuel	0
9	Residue leaving boiler/economizer, % Total	85
10	Output, 1,000,000 Btu/h	230.03
11	Additional theoretical air, lb/10,000 Btu Table 14, Item [21]	0
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0

FUEL - Biomass, Iowa

	15 Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
	Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
A	C	60.32	11.51	694.3		
B	S	1.37	4.32	5.9		
C	H_2	4.51	34.29	154.6	8.94	40.32
D	H_2O	13.12			1.00	13.12
E	N_2	1.29				
F	O_2	13.07	-4.32	-56.5		
G	Ash	6.32				
H	Total	100.00	Air	798.4	H2O	53.44

18	Higher heating value (HHV), Btu/lb fuel		10,757
19	Unburned carbon loss, % fuel input		0.28
20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.422
21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.20

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

			A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						7.400
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.061
24	Total residue, lb/10,000 Btu	[23] + [14]						0.061
25	Excess air, % by weight		39.2	0.0		39.2		39.2
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				10.304		10.304
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.050	0.050	0.050	0.050
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.497		0.497	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				0.869		0.869
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				11.224		11.224
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.547	0.547	0.547	0.547
35	Dry gas, lb/10,000 Btu	[33] - [34]				10.677		10.677
36	H_2O in gas, % in weight	100 x [34] / [33]				4.88		4.88
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.46		0.46

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses					
38	Dry Gas, %		0.0024 x [35d] x ([6] - [3])			7.62
39	Water from fuel, as fired %	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1231.1		
40		Enthalpy of water at T = [3]	H2 = [3] -32	48.0		
41			[29] x ([39] - [40]) / 100			5.88
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])			0.07
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]			0.28
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h		0.50
45	Other, % (include manufacturers margin if applicable)					1.50
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]			0.00
47	Summation of losses, %		Summation [38] through [46]			15.84
	Credits					
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])			-0.45
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])			0.00
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01	H @ 80 ~ 1.0	0.01
51	Other, %					0.00
52	Summation of credits, %		Summation [48] through [51]			-0.44
53	**Efficiency, %**		100 - [47] - [52]			**84.61**

KEY PERFORMANCE PARAMETERS

			Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		271.9
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		25.3
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	305.1	305.1
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	10.355	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	281.5	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha (Btu/lb) 41.40	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	266.9	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	874.7	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	2260.0	

University of Iowa Testing: Day 2, Biomass and Coal Mix, Run #6 03/14/2007

Combustion Calculations - Btu Method

INPUT CONDITIONS - BY TEST OR SPECIFICATION

1	Excess air: at burner/leaving boiler/econ, % by weight	38.3
2	Entering air temperature, F	58.48
3	Reference temperature, F	80
4	Fuel temperature, F	74.2
5	Air temperature leaving air heater, F	244.72
6	Flue gas temperature leaving (excluding leakage), F	376.55
7	Moisture in air, lb/lb dry air	0.0041
8	Additional moisture, lb/100 lb fuel	0
9	Residue leaving boiler/economizer, % Total	85
10	Output, 1,000,000 Btu/h	230.31
11	Additional theoretical air, lb/10,000 Btu Table 14, Item [21]	0
12	CO_2 from sorbent, lb/10,000 Btu Table 14, Item [19]	0
13	H_2O from sorbent, lb/10,000 Btu Table 14, Item [20]	0
14	Spent sorbent, lb/10,000 Btu Table 14, Item [24]	0

FUEL - Biomass, Iowa

15	Ultimate Analysis		16 Theo Air, lb/100 lb fuel		17 H_2O, lb/100 lb fuel	
	Constituent	% by weight	K1	[15] x K1	K2	[15] x K2
A	C	59.24	11.51	681.9		
B	S	1.38	4.32	6.0		
C	H_2	4.49	34.29	154.0	8.94	40.14
D	H_2O	13.18			1.00	13.18
E	N_2	1.11				
F	O_2	14.46	-4.32	-62.5		
G	Ash	6.14				
H	Total	100.00	Air	779.3	H2O	53.32

18	Higher heating value (HHV), Btu/lb fuel		10,555
19	Unburned carbon loss, % fuel input		0.27
20	Theoretical air, lb/10,000 Btu	[16H] x 100 / [18]	7.383
21	Unburned carbon, % of fuel	[19] x [18] / 14,500	0.19

COMBUSTION GAS CALCULATIONS, Quantity/10,000 Btu Fuel Input

			A At Burners	B Infiltration	C Leaving Furnace		D Leaving Blr/Econ	
22	Theoretical air (corrected), lb/10,000 Btu	[20] - [21] x 1151 / [18] + [11]						7.362
23	Residue from fuel, lb/10,000 Btu	([15G] + [21]) x 100 / [18]						0.060
24	Total residue, lb/10,000 Btu	[23] + [14]						0.060
25	Excess air, % by weight		38.3	0.0		38.3		38.3
26	Dry air, lb/10,000 Btu	(1 + [25] / 100) x [22]				10.184		10.184
27	H_2O from air, lb/10,000 Btu	[26] x [7]			0.042	0.042	0.042	0.042
28	Additional moisture, lb/10,000 Btu	[8] x 100 / [18]			0.000	0.000	0.000	0.000
29	H_2O from fuel, lb/10,000 Btu	[17H] x 100 / [18]			0.505		0.505	
30	Wet gas from fuel, lb/10,000 Btu	(100 - [15G] - [21]) x 100 / [18]				0.887		0.887
31	CO_2 from sorbent, lb/10,000 Btu	[12]				0.000		0.000
32	H_2O from sorbent, lb/10,000 Btu	[13]			0.000	0.000	0.000	0.000
33	Total wet gas, lb/10,000 Btu	Summation [26] through [32]				11.113		11.113
34	Water in wet gas, lb/10,000 Btu	Summation [27] + [28] + [29] + [32]			0.547	0.547	0.547	0.547
35	Dry gas, lb/10,000 Btu	[33] - [34]				10.566		10.566
36	H_2O in gas, % in weight	100 x [34] / [33]				4.92		4.92
37	Residue, % by weight (zero if < 0.15 lbm/10KB)	[9] x [24] / [33]				0.46		0.46

EFFICIENCY CALCULATIONS, % Input from Fuel

	Losses				
38	Dry Gas, %		0.0024 x [35d] x ([6] - [3])		7.52
39	Water from fuel, as fired %	Enthalpy of steam at 1 psi, T = [6]	H1 = (3.958E-5 x T + 0.4329) x T + 1062.2	1230.8	
40		Enthalpy of water at T = [3]	H2 = [3] -32	48.0	
41			[29] x ([39] - [40]) / 100		5.98
42	Moisture in air, %		0.0045 x [27D] x ([6] - [3])		0.06
43	Unburned carbon, %		[19] or [21] x 14,500 / [18]		0.27
44	Radiation and convection, %		ABMA curve, Chapter 23	based on output of plant Btu/h	0.70
45	Other, % (include manufacturers margin if applicable)				1.50
46	Sorbent net losses, % if sorbent is used		From Chapter 10, Table 14, Item [41]		0.00
47	Summation of losses, %		Summation [38] through [46]		16.02
	Credits				
48	Heat in dry air, %		0.0024 x [26D] x ([2] - [3])		-0.53
49	Heat in moisture in air, %		0.0045 x [27D] x ([2] - [3])		0.00
50	Sensible heat in fuel, %		(H at T[4] - H at T[3]) x 100 / [18]	0.01 / H @ 80 ~ 1.0	0.01
51	Other, %				0.00
52	Summation of credits, %		Summation [48] through [51]		-0.52
53	**Efficiency, %**		100 - [47] - [52]		**84.50**

KEY PERFORMANCE PARAMETERS

			Leaving Furnace	Leaving Blr/Econ
54	Input from fuel, 1,000,000 Btu/h	100 x [10] / [53]		272.5
55	Fuel rate, 1000 lb/h	1000 x [54] / [18]		25.8
56	Wet gas weight, 1000 lb/h	[54] x [33] / 10	302.9	302.9
57	Air to burners (wet), lb/10,000 Btu	(1 +[7]) x (1 + [25A] / 100) x [22]	10.226	
58	Air to burners (wet), 1000 lb/h	[54] x [57] / 10	278.7	
59	Heat available, 1,000,000 Btu/h	[54] x {([18] - 10.30 x [17H]) / [18] - 0.005		
	Ha (Btu/lb) 40.85	x ([44] + [45]) + Ha at T[5] x [57] / 10,000}	266.8	
60	Heat available/lb wet gas, Btu/lb	1000 x [59] / [56]	880.7	
61	Adiabatic flame temperature, F	From Chapter 10, Fig.3 at H = [60], % H2O = [36]	2875.0	

Appendix D

Electrostatic Precipitator Data

Summary of Electrostatic Precipitator Voltages

	Panel A		Panel B		Panel C	
Run ID	**Primary Voltage**	**Precipitator Voltage**	**Primary Voltage**	**Precipitator Voltage**	**Primary Voltage**	**Precipitator Voltage**
1	295	34	337	36	333	46
2	301	33	333	36	330	46
3	299	33	330	36	330	46
4	294	33	333	34	329	46
5	283	32	338	36	326	46
6	278	32	332	36	328	46
7	290	34	345	36	330	46