JV TASK 35 – EVALUATION OF AEROSOL EMISSIONS DOWNSTREAM OF AN AMMONIA-BASED SO₂ SCRUBBER

Evaluation of a Wet ESP for Reducing SO₃ Aerosol Emissions

Final Report

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NOMENCLATURE

APCD	air pollution control device
APS	aerodynamic particle sizer
ASTM	American Society for Testing and Materials
CAH	convective air heater
CHN	carbon, hydrogen, nitrogen
CPC	condensation particle counter
CVAA	cold-vapor atomic adsorption
D ₅₀	diameter where 50% are larger and 50% smaller
DOE	U.S. Department of Energy
EEC	Environmental Elements Corporation
EERC	Energy & Environmental Research Center
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FD	forced draft
FGD	flue gas desulfurization
FGR	flue gas recirculation
HTHX	high-temperature heat exchanger
HVT	high-velocity thermocouples
ID	induced draft
IFRF	International Flame Research Foundation
IR	infrared
IRZ	internal recirculation zone
JV	Joint Venture
LOI	loss on ignition
MET	Marsulex Environmental Technologies LLC
NO _x	nitrogen oxide and nitrogen dioxide
pc	pulverized coal
pf	pulverized fuel
PSD	particle-size distribution
PVC	polyvinyl chloride
SCA	specific collection area
SCR	selective catalytic reduction
SFS	slagging furnace system
SMPS	scanning mobility particle sizer
SS	stainless steel
TVA	Tennessee Valley Authority
UV	ultraviolet
XRF	x-ray fluorescence

JV TASK 35 – EVALUATION OF AEROSOL EMISSIONS DOWNSTREAM OF AN AMMONIA-BASED SO₂ SCRUBBER

EXECUTIVE SUMMARY

Introduction

Depending on the size and type of boiler, the 1990 Clean Air Act Amendments required specific reductions in SO₂ emissions from coal-fired electric utilities. To meet these requirements, SO₂ reduction strategies have included installing scrubbing technology, switching to a more expensive low-sulfur coal, or purchasing SO₂ allowances. It is expected that over the next 10 years there will be an increase in the price of low-sulfur coals, but that higher-sulfur coal costs will remain the same. Technologies must be strongly considered that allow the use of high-sulfur fuels while at the same time meeting current and future SO₂ emission limits. One such technology is the ammonia-based flue gas desulfurization (FGD) (NH₃-based FGD) system manufactured by Marsulex Environmental Technologies (MET). The MET scrubber is a patented NH₃-based FGD process that efficiently converts SO₂ (>95%) into a fertilizer product, ammonium sulfate ([NH₄]₂SO₄).

A point of concern for the MET technology, as well as other FGD systems, is the emission of sulfuric acid/SO₃ aerosols that could result in increased opacity at the stack. This is a direct result of firing high-sulfur fuels that naturally generate more SO₃ than do low-sulfur coals. SO₃ is formed during the coal combustion process. SO₃ is converted to gaseous H₂SO₄ by homogeneous condensation, leading to a submicron acid fume that is very difficult to capture in a dry electrostatic precipitator (ESP). The condensed acid can also combine with the fly ash in the duct and scale the duct wall, potentially resulting in corrosion of both metallic and nonmetallic surfaces. Therefore, SO₃ in flue gas can have a significant impact on the performance of coal-fired utility boilers, air heaters, and ESPs. In addition to corrosion problems, excess SO₃ emissions can result in plume opacity problems.

Thus the Energy & Environmental Research Center (EERC) was contracted by MET and the U.S. Department of Energy (DOE) to evaluate the potential of a wet ESP for reducing SO₃ emissions. The work consisted of pilot-scale tests using the EERC's slagging furnace system (SFS) to determine the effectiveness of a wet ESP to control SO₃/H₂SO₄ aerosol emissions in conjunction with a dry ESP and MET's NH₃-based FGD. Because these compounds are in the form of fine particles, it is speculated that a relatively small, highly efficient wet ESP following the MET scrubber would remove these fine aerosol particles. The performance target for the wet ESP was a particulate mass collection efficiency of >90%; this level of performance would likely ensure a stack opacity of <10%.

Approach

Pilot-scale tests to evaluate the combined performance of a dry ESP, a MET NH₃-based FGD scrubbing system, and a wet ESP were conducted by firing a high-sulfur bituminous coal and petroleum coke blend in EERC's ~2.5-MMBtu/hr (2.6×10^6 kJ/hr) pilot-scale combustor referred to

as the SFS. A dry ESP and NH₃-based FGD built by MET were installed prior to a wet ESP. The wet ESP used for the project was designed and built by Environmental Elements.

The pilot-scale tests consisted of 3 weeks of testing. The first week involved shakedown of the installed equipment. The second week (referred to as Test Series I) evaluated the effectiveness of the wet ESP to remove fine particles/SO₃ aerosols from the flue gas stream. The third week (Test Series II) completed a parametric evaluation of particulate removal efficiency of the wet ESP after modifications had been made to improve the overall electric field of the unit.

Once installation of the dry ESP, MET scrubber, and wet ESP was completed and a shakedown test performed, two different tests series were completed. The first, a 6-day pilot-scale test, was conducted to document the performance of the dry ESP, MET NH₃-based FGD, and wet ESP. The second series of tests was a parametric evaluation based on SO₃ concentration and humidification. The tests were conducted using a blend of Robinson Run eastern bituminous coal and a petroleum coke. Analysis of these fuels is shown in Table ES-1. The points sampled are shown in Table ES-2. In addition to the standard flue gas constituents of SO₂, CO₂, NO_x, CO, and O₂, the following flue gas constituents were measured at some or all of the sample points:

- SO₃
- NH₃
- Chlorides
- Particulate matter (total mass and particle-size distributions)
- Hg

For Test Series I, a 6-day test was completed, firing a blend of 80% coal and 20% petroleum coke. The conditions remained the same for the entire 6 days. For Test Series II, the test plan is shown in Table ES-3.

Results

The particulate removal efficiency across each of the two pilot-scale ESPs is shown in Table ES-4. The particulate removal efficiency of the dry ESP was relatively low, ranging from about 75% to 94%. This low removal efficiency is consistent with the low ESP SCA (specific collection area) of ~80–90 and occasional problems with power supply performance. Typically, dry ESP will have SCAs of 300–500.

The primary objective of this effort was to determine the efficiency of the wet ESP to remove SO₃ aerosols and reaction products. The goal was to achieve 90% removal across the wet ESP. **It is clear from the data in Table ES-4 that the wet ESP in the configuration used for Test Series I did not achieve the desired level of control.** With only a few exceptions, the collection efficiency was less than 80%. This level of control, more than likely, would not allow a full-scale system to achieve less than 10% opacity at the stack. Based on the data, to obtain a higher level of control, the power input to the wet ESP electrodes must be increased. Therefore, it was decided that modifications to the wet ESP would be necessary, followed by additional testing (Test Series II) to prove 90% control could be achieved.

Table ES-1. Analysis of Fuels Used for Test Series I, on a dry basis

	Robinson Run Bituminous Coal	Petroleum Coke
<i>Proximate Analysis, wt%</i>	<i>3 analyses</i>	<i>2 analyses</i>
Moisture Content	1.03	0.65
Volatile Matter	40.68	11.72
Fixed Carbon	44.36	86.5
Ash	14.95	1.14
<i>Ultimate Analysis, wt%</i>	<i>3 analyses</i>	<i>1 analysis</i>
Hydrogen	4.76	3.48
Carbon	70.49	86.0
Nitrogen	1.72	2.41
Sulfur	4.18	6.84
Oxygen, by difference	3.90	0.12
Heating Value, Btu/lb	12,704	14,944
<i>Ash Fusion Temperatures, °F</i>	<i>3 analyses</i>	<i>1 analysis</i>
Initial Temperature	2413	2324
Softening Temperature	2450	2484
Hemi. Temperature	2522	2343
Fluid Temperature	2565	2460
<i>Coal Analysis</i>	<i>2 analyses</i>	<i>1 analysis</i>
Mercury, µg/g	0.0807	0.0038
Chlorides, µg/g	508	<50
<i>Coal Ash Analysis, % conc. as oxides</i>	<i>2 analyses</i>	<i>1 analysis</i>
SiO ₂	46.4	46.1
Al ₂ O ₃	23.1	13.5
Fe ₂ O ₃	16.3	21.7
TiO ₂	0.91	1.01
P ₂ O ₅	0.17	0.27
CaO	3.38	4.99
MgO	1.80	2.95
Na ₂ O	1.02	2.12
K ₂ O	2.12	5.78
BaO	0.10	<0.02
MnO	0.03	<0.02
SrO	0.10	<0.02
SO ₃	4.41	1.51
<i>Coal Ash Analysis, mg/kg</i>	<i>2 analyses</i>	<i>1 analysis</i>
Cr	143	<100
Cu	<100	<100
Ni	<100	3.5%
V	173	21%
Zn	<103	180

Note: Ni and V values are for information only. Values reported are above the calibration range of the instrument.

Table ES-2. Sampling Point Locations for the Pilot-Scale System

Sampling Point No.	Sampling Point Location
—	Outlet of the combustor
1	Inlet of the dry ESP
2	Outlet of the dry ESP/inlet of the MET FGD
3	Outlet of the MET FDG/inlet of the wet ESP
4	Outlet of the wet ESP

Table ES-3. Variables for Test Series II

Test No.	Humidification	Petroleum Coke, wt% ¹	Gas Velocity through Wet ESP, ft/sec
1	No	None	9
2	No	20	9
3	No	30	9
4	Yes	20	9
5	Yes	30	9
6	No	20	10

¹ The coal was a Robinson Run eastern bituminous coal.

Table ES-4. Particulate Removal Efficiencies for Test Series I

Test Period	Dry ESP Removal, %	Wet ESP Removal, %
1	94.15	83.11
2	75.27	60.45
		63.35
3	86.67	55.68
	75.80	55.05
		47.67
4	—	80.55
		87.43
		79.44
5	94.49	72.31
		72.23

The Test Series I mass loading ratios at the inlet and outlet of the wet ESP are shown in Table ES-5. An attempt was made to determine the composition of the particulate matter exiting the NH₃-based FGD and the wet ESP. Possible sulfated components of the particulate matter are ammonium sulfate, ammonium bisulfate, SO₃ aerosols, and sulfated fly ash particles (CaSO₄ and Na₂SO₄, etc.). If all the NH₃ measured in the particulate matter reacted with SO₃ to form (NH₄)₂SO₄, the mass ratio of NH₃ to SO₃ would be 0.425. If, however, (NH₄)HSO₄ is formed, the ratio would be 0.212. (NH₄)HSO₄ reaction product would form if the system was ammonia-starved. As can be seen from Table ES-6, this ratio was generally between 0.425 and 0.212 at both the inlet and outlet of the wet ESP, indicating that both reactions were occurring. If the total measured mass at each location is compared to measured mass of NH₄ plus SO₄ (last column in Table ES-5), it appears that particulate matter is composed of other components in addition to the NH₃-SO₄ products.

As stated, between Test Series I and II, several modifications were made to the wet ESP. The first change involved the installation of a distributor plate in the inlet of the first field to ensure more uniform flow distribution across the field, minimizing the potential for gas sneakage along the electrode mast. The second modification made to the wet ESP was to replace the two electrode masts. Installation of a longer electrode mast in the second field also required adding 4 ft (1.2 m) to the length of the chamber and modifying outlet piping. There was no change to the total effective collection area as a result of the modifications, because the electrode in the first field was shortened by 4 ft (1.2 m). However, collection area distribution between the fields changed significantly. Other changes to the electrode masts were made, which resulted in an overall increase in power input to each field and the ability to increase current levels for any given voltage.

Table ES-5. NH₃/Sulfate Balances at the Inlet and Outlet of the Wet ESP for Test Series I

Date	Total Mass Loading, gr/scf	Measured NH ₃ /SO ₃ Mass Ratio	Mass NH ₄ -SO ₄ Products to Total Mass, wt%
<i>Wet ESP Inlet</i>			
4-23	0.1664	0.396	78.2
4-24	0.1583	0.259	71.3
4-24	0.1741	0.231	81.8
4-25	0.1848	0.261	91.2
4-25	0.1565	0.238	88.1
4-25	0.1565	0.374	101.3
4-26	0.1666	0.465	114.7
4-27	0.1105	0.327	94.0
<i>Wet ESP Outlet</i>			
4-23	0.0281	0.333	87.9
4-24	0.0626	0.248	99.7
4-24	0.0638	0.270	70.8
4-25	0.0819	0.434	89.2
4-25	0.0819	0.296	89.9
4-26	0.0324	0.451	123.9

The final change involved replacing both of the power supplies and controllers supporting the wet ESP in an attempt to increase power input to both fields. For the first field, the original power supply and analog controller were replaced with an electronic power supply and controller the EERC had available from another project. The advantage of the electronic power supply was that a spark rate could be set. The electronic controller, eliminating the need to manually reset the power supply, then handled sparking events. For the second field of the wet ESP, the power supply and controller were switched with one of the power supplies and controller originally used on the dry ESP. This change was made to increase the potential current input from 0 to 10 to 0 to 75 mA. As a result of these changes, performance of the wet ESP significantly improved for the tests conducted in Test Series II.

The changes in the electric fields resulted in greatly increased power to the wet ESP, as is shown in Table ES-6. Although the voltages were about the same, the current generated was much higher in Test Series II. This resulted in much improved particulate collection efficiency for the wet ESP, as shown in Table ES-7. Except for when the power supply to the second field tripped out during sampling, >90% particulate collection efficiency was achieved for all the tests. The effectiveness of the wet ESP is very evident in the photographs of the EERC SFS stack (Figures ES-1 and ES-2). The plume is clearly visible when the wet ESP is bypassed compared to a clear stack when the wet ESP is operating.

The mass loading ratios at the inlet and outlet of the wet ESP were similar to those obtained during Test Series I. Although the NH_3/SO_3 ratio is somewhat lower than was the case for Test Series I, as can be seen from Table ES-8, it was generally between 0.425 and 0.212 at both the inlet and outlet of the wet ESP, again indicating that both sulfates and bisulfates were being formed. If the total measured mass at the inlet is compared to the measured mass of NH_4 plus SO_4 (last column in Table ES-7), it shows that the particulate matter was almost entirely $\text{NH}_4\text{--SO}_4$ reaction products. This indicates that the dry ESP/ NH_3 -based FGD removed fly ash more efficiently compared to the first test series (Table ES-5), where most of the values were <100%.

Conclusions

For the EERC pilot-scale tests evaluating the ability of a wet ESP to remove particulate matter following an MET NH_3 -based FGD system, the following conclusions/observations are made:

- In Test Series I, the overall particulate removal efficiency of the wet ESP averaged about 70%. From these data, it is clear that the wet ESP used in the configuration in Test Series I did not achieve the desired 90% control.

Table ES-6. Average Wet ESP Voltages and Currents for Test Series I and II

Test Series	Voltage Field 1, kV	Current Field 1, mA	Voltage Field 2, kV	Current Field 2, mA
I	39.81	0.576	44.928	0.834
II	48.88	1.667	42.100	6.862

Table ES-7. Particulate Removal Efficiencies for Each of the Two ESPs for Test Series II

Test Period	Dry ESP Removal, %	Wet ESP Removal, %
1	86.74	91.53
1		78.88 ¹
2	69.77	97.00
2		86.82 ¹
2		97.49
3	80.88	96.43
3	57.13	98.01
		96.35
4	96.79	98.51
4	96.26	99.57
4		96.65
5	93.55	99.62
5	82.53	99.63
5		95.91
6	93.02	96.36
6	96.34	95.19
6		89.07 ¹

¹ The power to the wet ESP tripped out during test.

- After modification of the wet ESP electrode mast and the wet ESP fields prior to Test Series II, much higher current levels were obtained compared to Test Series I. As a result, >90% particulate removal efficiency was obtained across the wet ESP for all tests.
- For both Test Series I and II, the mass balance ratios between NH_3 and SO_3 indicated that the particulate matter at the exit of the MET NH_3 -based FGD is mostly $(\text{NH}_4)_2\text{SO}_4$, but reactions resulting in the formation of NH_3HSO_4 were also occurring.
- The dry ESP was not very efficient in either Test Series I or II. However, humidification did improve performance most likely by increasing the average particle-size diameter.
- The coal and petroleum coke were the same for both Test Series I and II, based on the analysis of the two fuels.

Figure ES-1. Photograph of the EERC SFS stack with the wet ESP off-line.

Figure ES-2. Photograph of the EERC SFS stack with the wet ESP on-line.

Table ES-8. Sulfate/NH₃ Mass Balances at the Inlet and Outlet of the Wet ESP for Test Series II

Test No.	Total Mass Loading, gr/scf	Measured NH ₃ /SO ₃ Mass Ratio	Mass NH ₄ -SO ₄ Products to Total Mass, %
<i>Wet ESP Inlet</i>			
1	0.1299	0.397	102.0
1	0.1269	0.461	96.5
2	0.1402	0.160	101.2
2	0.1510	0.259	87.7
2	0.1275	0.260	92.4
3	0.1737	0.154	84.9
3	0.1662	0.254	78.9
3	0.1700	0.191	82.3
4	0.0201	0.311	104.9
4	0.0232	0.407	97.4
4	0.0269	0.409	102.1
5	0.0265	0.404	105.5
5	0.0273	0.240	113.4
6	0.1730	0.190	91.0
6	0.1766	0.274	93.3
6	0.1739	0.252	93.8
<i>Wet ESP Outlet</i>			
1	0.0110	0.229	96.8
1	0.0268	0.381	107.4
2	0.0042	0.201	83.0
2	0.0199	0.239	98.2
2	0.0032	0.235	81.3
3	0.0062	0.208	71.5
3	0.0033	0.324	70.4
3	0.0062	0.239	50.1
4	0.0003	— ¹	—
4	0.0001	—	—
4	0.0009	—	—
5	0.0001	—	—
5	0.0001	—	—
5	0.0011	—	—
6	0.0063	0.254	86.4
6	0.0085	0.312	101.9
6	0.0190	0.386	482.2

¹ Outlet mass loading values are too low to arrive at a meaningful number.

JV TASK 35 – EVALUATION OF AEROSOL EMISSIONS DOWNSTREAM OF AN AMMONIA-BASED SO₂ SCRUBBER

1.0 INTRODUCTION

Depending on the size and type of boiler, the 1990 Clean Air Act Amendments required specific reductions in SO₂ emissions from coal-fired electric utilities. To meet these requirements, SO₂ reduction strategies have included installing scrubbing technology, switching to a more expensive low-sulfur coal, or purchasing SO₂ allowances. It is expected that, over the next 10 years, there will be an increase in the price of low-sulfur coals but the higher-sulfur coal cost will remain the same. The market for SO₂ allowances has been extremely volatile over the past 3 years: from a low cost of about \$100 to a high of about \$210 per ton of SO₂ emitted. It is expected that the purchase of these credits will also increase during the next several years. Technologies that allow the use of high-sulfur fuels while at the same time meeting current and future SO₂ emission limits must be strongly considered. One such technology is the ammonia-based flue gas desulfurization (NH₃-based flue gas desulfurization [FGD]) system manufactured by Marsulex Environmental Technologies (MET).

The MET scrubber is a patented NH₃-based FGD process that efficiently converts SO₂ (>95%) into a fertilizer product, ammonium sulfate ((NH₄)₂SO₄). There are four major economic benefits to using the MET technology: reduced fuel cost, increased load factor, production of the (NH₄)₂SO₄ product, and the sale of SO₂ allowances. In one market strategy, MET would build, own, and operate the scrubber system, charging a fee for SO₂ control. By paying an SO₂ control fee to MET, the utility avoids significant capital investment, has no chemical or by-product handling issues, and is guaranteed long-term environmental compliance.

A point of concern for the MET technology as well as other FGD systems is the emission of sulfuric acid/SO₃ aerosols that could result in increased opacity at the stack. This is a direct result of firing high-sulfur fuels that naturally generate more SO₃ than do low-sulfur coals. Also, the expected increase in the use of selective catalytic reduction (SCR) for NO_x control may increase flue gas SO₃ concentrations. The problem may be further exacerbated by fine particles formed by the reaction of SO₃ with any excess ammonia present in the flue gas. Pilot-scale testing of the MET scrubber firing natural gas and adding SO₂, SO₃ (in expected proportions), and ammonia has resulted in what is referred to as a “blue plume.”

SO₃ is formed during the coal combustion process (0.7% of total sulfur emissions, according to the U.S. Environmental Protection Agency [EPA]). Chemical equilibrium calculations show all the SO₃ is converted to gaseous H₂SO₄ at a typical flue gas temperatures of 400°F (204°C) or less. At temperatures below the sulfuric acid dewpoint (typically 260°–300°F [127°–149°C], depending on moisture and SO₃ concentration), homogeneous condensation may occur, leading to a submicron acid fume, which is very difficult to capture in a dry electrostatic precipitator (ESP). The condensed acid can also combine with the fly ash in the duct and scale the duct wall and stack wall with an acid–ash mixture. The resulting iron sulfate and/or chromic acid can create severe corrosion on both metallic and nonmetallic surfaces. Therefore, SO₃ in flue gas can have a significant impact on the performance of coal-fired utility boilers, air heaters, and ESPs. In addition to corrosion problems,

excess SO₃ emissions can result in plume opacity problems. Thus the Energy & Environmental Research Center (EERC) was contracted by MET and the U.S. Department of Energy (DOE) to evaluate the potential of a wet ESP for reducing SO₃ emissions. Pilot-scale tests were completed to determine the effectiveness of a wet ESP to remove SO₃/H₂SO₄ aerosols in conjunction with a dry ESP and MET's NH₃-based FGD using EERC's slagging furnace system (SFS). Because these compounds are in the form of fine particles, it was speculated that a relatively small (in comparison to conventional dry ESPs), highly efficient wet ESP following the MET NH₃-based FGD would remove these fine aerosol particles.

2.0 PROJECT GOALS AND OBJECTIVES

The overall goal of the project was to evaluate the effectiveness of a wet ESP for SO₃ control for fossil fuel-fired power plants. Specific objectives were as follows:

- Determine whether a wet ESP will effectively control aerosol/fine particulate emissions from the MET NH₃-based FGD. To accomplish this objective, the following were done:
 - An NH₃-based FGD absorber tower and a dry and wet ESP were installed at the EERC. Flue gas was generated with an existing 2.5-MMBtu/hr (2.6×10^6 kJ/hr) pilot-scale SFS combustor.
 - Aerosol and particulate matter were characterized at the inlet and outlet of each air pollution control device (APCD).
 - A humidification system was installed to determine the impact of humidification on SO₃ emissions.

3.0 TEST FACILITIES

Pilot-scale tests to evaluate the combined performance of a dry ESP, a MET NH₃-based FGD scrubbing system, and a wet ESP were conducted by firing a high-sulfur bituminous coal and petroleum coke blend in the EERC's ~2.5-MMBtu/hr (2.6×10^6 kJ/hr) pilot-scale combustor referred to as the SFS. This unit was originally equipped with a baghouse as the downstream particulate control device. However, for this work, a dry ESP, built by MET, was installed and the baghouse bypassed. The wet ESP used for the project was designed and built by Environmental Elements. The MET NH₃-based FGD, previously located at Santee Cooper's Winyah Station, was dismantled, shipped to the EERC, and installed between the dry ESP and the wet ESP.

3.1 Description of the EERC Pilot-Scale Combustor

The EERC pilot-scale SFS that supported the project began operating in 1997. The unit was originally designed to operate at very high temperatures (2700°–2900°F [1482°–1593°C] at the furnace exit), providing higher thermal conversion efficiencies than conventional pc-fired boilers. In the high-temperature mode, a substantial portion of the ash generated is removed from the system as slag. For

more than 3 years, the SFS has been operated in support of an advanced power system project while firing bituminous and subbituminous coals and lignite. However, for this project, the furnace was operated as a conventional pulverized coal (pc)-fired boiler with a furnace exit temperature of 2000° to 2400°F (1093°–1316°C). A diagram and a photograph of the SFS are shown in Figures 3-1 and 3-2. A description of the various parts of the system is presented below.

3.1.1 Fuel Feed System

The coal feeder for the SFS was manufactured by K-Tron. Coal feed system components include two intermediate coal hoppers with pneumatically actuated valves to minimize the possibility of coal feed interruptions caused by plugging, bridging, or valve failure in a single intermediate hopper. Each intermediate hopper has a level indicator along with hopper vents and dust collectors. The programmable controller for the coal feeder is integrated with the data acquisition system.

Desired feed rate ranges can be achieved by proper screw selection as well as changing the coal feeder gear ratio (permitting a fivefold increase or decrease in feed rate capacity). Controlled feed rates as low as 60 lb/hr (27 kg/hr) and as high as 400 lb/hr (182 kg/hr) have been demonstrated. The maximum potential coal feed rate is believed to be about 1500 lb/hr (681 kg/hr).

Natural gas can also be fired in the SFS. Natural gas is delivered to the SFS at about 12 psig (0.9 bar). The natural gas system includes piping, valve/control systems, and flame safety systems for the main and auxiliary burners as well as the slag tap burners. Although natural gas can be utilized as the primary fuel, generally the purpose of the natural gas system is to support main burner operation during heatup and cool down. Auxiliary burner firing is used, as necessary, to control furnace exit and slag screen temperatures.

3.1.2 Pilot-Scale Slagging Furnace

The pilot-scale slagging furnace design is intended to be as fuel-flexible as possible, with maximum furnace exit temperatures of 2700° to 2900°F (1482° to 1593°C) in order to achieve desired furnace conditions to support high-temperature heat exchanger (HTHX) development projects and operate the combustor in a slagging mode. It has a nominal firing rate of 2.5 MMBtu/hr (2.6×10^6 kJ/hr) and a range of 2.0 to 3.0 MMBtu/hr (2.1 to 3.2×10^6 kJ/hr) using a single burner. The design is based on firing a bituminous coal (Illinois No. 6 – 11,100 Btu/lb, or [25,800 kJ/kg]) and a nominal furnace residence time of 3.2 s. Resulting flue gas flow rates range from 425 to 645 scfm (12.0 to 18.6 m³/min), with a nominal value of 530 scfm (15 m³/min) based on 20% excess air. Firing a subbituminous coal or lignite increases the flue gas volume, thereby decreasing residence time to about 2.6 s. However, the high furnace temperature and volatility of the low-rank fuels result in high combustion efficiency (>99%). The SFS furnace is oriented vertically (downfired) with a burner design based on that of a swirl burner currently used on two smaller EERC pilot-scale pc-fired units. Slagging furnace dimensions are 47 in. (119 cm) inside diameter (i.d.) by 16 ft (4.9 m) in length. Table 3-1 summarizes the volumetric flow rate and temperature data upon which the furnace design was based.

Figure 3-1. Schematic of the EERC SFS.

Figure 3-2. Photograph of the EERC SFS.

Table 3-1. Theoretical Flow and Heat-Transfer Data for the Slagging Furnace and Refractory Ducts (based on Illinois No. 6 bituminous coal)*

Furnace Firing Rate, MMBtu/hr	2.0	2.5	3.0	2.0	2.5	3.0
<i>General Furnace Data</i>						
Furnace i.d., in.	47	47	47	<i>Furnace Exit/Slag Screen</i>		
Furnace Length, ft	16	16	16	Total Flue Gas Flow, scfm	592	646
Refract. 1 Thickness, in.	4	4	4	Total Flue Gas Flow, acfm	3598	4029
Refract. 2 Thickness, in.	4	4	4	Furnace Exit Vel., ft/s	33.2	37.2
Refract. 3 Thickness, in.	3.25	3.25	3.25	Slag Screen Exit Gas Vel., ft/s	66.4	74.4
Furnace Weight, tons	14.4	14.4	14.4	<i>Dilution Gas Requirements</i>		
Coal Feed Rate, lb/hr	176	220	264	Inlet Gas Temp., °F	2520	2540
Airflow Rate, scfm	398	497	597	Gas Velocity In, ft/s	61.3	69.2
Flue Gas Flow Rate, scfm	428	536	643	Exit Gas Temp., °F	1855	1850
Flue Gas Flow Rate, acfm	2683	3412	4155	Dilution Gas Temp., °F	300	300
Furnace Gas Velocity, ft/s	3.7	4.7	5.7	Dilution Gas Flow, scfm	248	289
Flue Gas Residence Time, s	4.1	3.2	2.6	Total Flue Gas Flow, scfm	840	952
<i>Furnace Temperatures</i>						
Inlet Gas Temp., °F	2900	3000	3100	Flue Gas Flow Rate Out, acfm	3740	4229
Avg. Gas Temp., °F	2800	2850	2900	Gas Velocity Out, ft/s	67.6	76.5
Exit Gas Temp., °F	2700	2700	2700	<i>Dilution Gas Nozzles</i>		
Refract. 1 Surf. Temp., °F	2677	2728	2777	Nozzle Diameter, in.	1.25	1.25
Refract. 2 Surf. Temp., °F	2431	2477	2521	No. of Nozzles	8	8
Refract. 3 Surf. Temp., °F	1751	1783	1815	Dilution Gas Flow, acfm	362	422
Skin Temp., °F	275	279	283	Dilution Gas Velocity, ft/s	89	103
<i>Convective Air Heater</i>						
Auxiliary Burner, scfm	164	110	20	Gas Temp., °F	1800	1800
Auxiliary Burner, kBtu/hr	890	560	110	Flue Gas Flow Rate, acfm	3651	4138
Total Firing Rate, kBtu/hr	2890	3060	3110	Gas Velocity, ft/s	52.2	59.1
Wall Losses, kBtu/hr	194	202	209			
RAH Losses, kBtu/hr	190	190	190			

*Assumption: excess air is 20%.

The vertically oriented furnace shell was designed to include four distinct furnace sections, illustrated in Figure 3-1. The top section of the furnace supports the main burner connection. The upper-middle furnace section provides a location for installation of one or two HTHXs in the furnace wall. The lower-middle furnace section supports the auxiliary gas burner; the bottom section of the furnace includes the furnace exit to the slag screen as well as the slag tap opening. Construction materials for the furnace shell are mostly carbon steel. The only exceptions are the flanged pipe connections for the main and auxiliary burners and the sight ports; since their refractory protection is limited, they are made of stainless steel.

Temperature measurement in the furnace is accomplished using Type S thermocouples and optical pyrometers. The optical pyrometers are mounted in relatively permanent locations to measure furnace flame temperature, flue gas temperature near the surface of a HTHX located in the furnace wall, and at the furnace exit. Operating experience has shown optical pyrometer performance to be acceptable when compared with Type S thermocouples while natural gas and pulverized coal are fired. Verification of optical pyrometer performance is accomplished during each SFS operating period using Type S thermocouple data while natural gas and pulverized coal are fired.

Observation ports are located in the furnace to permit visual observation of the main burner flame, auxiliary burner flame, HTHXs, slag screen, and slag tap. When HTHXs are not installed as was the case for this project, additional access ports are available in the blank doors in the main furnace section.

Secondary combustion air preheat control capabilities for the main burner are limited to a control range of 600° to 800°F (316° to 427°C), depending on ambient air temperatures and forced-draft (FD) fan capacity. Two tube-and-shell heat exchangers are operated in series to recover heat from the flue gas to preheat secondary combustion air for the main burner. Primary combustion air for the main burner is not heated. Since the auxiliary burner is only natural gas-fired, neither the primary nor secondary air sources for this burner are heated.

The refractory walls in the slagging furnace consist of three castable refractory layers: a high-density slag-resistant material, an intermediate refractory, and a low-density insulating refractory. Three refractory layers were selected as a cost-effective approach to keep the overall size and weight of the system to a minimum while slag corrosion and heat loss are reduced.

3.1.3 Main and Auxiliary Burners

The main burner is natural gas- and pc-capable, 70% –200 mesh (70% –75 μm), with some burner turndown factored into the design. Flame stability is assessed by observing the flame and its relation to the burner quarl as a function of secondary air swirl and operating conditions at full load and under turndown conditions. The basic burner design, an International Flame Research Foundation (IFRF)-type adjustable secondary air swirl generator, is illustrated in Figure 3-3. An IFRF-type adjustable secondary air swirl generator uses primary and secondary air at approximately 15% and 85% of the total air, respectively, to adjust swirl between 0 and a maximum of 1.9. Swirl is defined as the ratio of the radial (tangential) momentum to axial momentum imparted to the secondary air by movable blocks internal to the burner and is used to set up an internal recirculation zone (IRZ) within the flame that allows greater mixing of combustion air and coal.

Figure 3-3. Schematic of the SFS basic burner design, an IFRF-type adjustable secondary-air swirl generator.

Secondary air swirl is used to stabilize the flame. In the absence of swirl, loss of flame may result, increasing the risk of a dust explosion. As swirl is applied to the combustion air, coal particles are entrained in the IRZ, increasing the heating rate of the particles, leading to increased release of volatiles and char combustion. The flame becomes more compact and intense as swirl is increased to an optimum level, which is characterized in EERC pilot-scale test facilities as the point at which the flame makes contact with the burner quarl. Increasing swirl beyond this level can pull the flame into the burner region, unnecessarily exposing metal burner components to the intense heat of the flame and possible combustion in the coal pipe.

Increasing swirl to provide flame stability and increased carbon conversion can also affect the formation of NO_x . The high flame temperatures and increased coal-air mixing associated with increased swirl create an ideal situation under which NO_x may form. In full-scale burners with adjustable vanes, swirl is often increased to reach the optimum condition and then decreased slightly to reduce the production of NO_x . Although NO_x emissions are of interest, their control was not a key objective for the SFS pilot-scale tests. Therefore, burner operational settings were based on achieving desired furnace exit temperatures and slag conditions in the furnace. Flame stability under turndown conditions is characterized by firing the primary burner at reduced load (typically 66% to 85% of the full load rate), maintaining the same primary airflow, and adjusting the secondary airflow to meet excess air requirements.

Materials of construction for the main burner are entirely stainless steel because of the combustion air (up to 800°F or 427°C) temperature ranges to which it is exposed. Combustion

airflow rates through the main burner range from about 400 to 600 scfm (11 to 17 m³/min), depending on furnace firing rate and fuel type fired (bituminous, subbituminous, or lignite).

In order to control furnace exit temperature, an auxiliary gas burner (850,000 Btu/hr or 896,750 kJ/hr) is located near the furnace exit. This auxiliary burner is used to compensate for heat losses through the furnace walls, sight ports, and HTHXs (when used). The use of the auxiliary gas burner is beneficial during start-up to reduce heatup time. The auxiliary gas burner firing rate is dependent on main burner fuel properties, desired furnace exit temperature, and heat losses from the furnace. The auxiliary burner is a smaller version of the main burner design. Materials of construction for the auxiliary burner are entirely stainless steel.

As stated earlier, thermocouples are installed to measure inlet combustion air temperatures for each burner. Thermocouple data are automatically logged into the data acquisition system. Pressure transmitters and gauges are used to monitor static and differential pressures in order to monitor burner performance and measure combustion airflow rate. These data are also automatically logged into the data acquisition system, and flow control valves are used to adjust and maintain desired combustion airflow rates. As a backup, burner data are recorded manually on data sheets on a periodic basis.

3.1.4 Furnace HTHX, Slag Screen, Dilution/Quench Zone, Convective Air Heater, and Process Air Heaters

These systems are all part of the high temperature, advanced combustion design of the SFS. For this project, the furnace HTHX and slag screen were not installed. The flue gas recirculation system of the dilution/quench zone was shut off to maintain proper flow rates to the MET NH₃-based FGD. Although the convective air heater and process air heaters were used, the purpose of the project was not to evaluate these systems. Therefore, no detailed description or discussion of any of these systems is presented in this report. However, the location of these systems are shown in Figures 3-1 and 3-2, and a detailed description of each system was presented in a final report to DOE (1).

3.1.5 Slagging Furnace System Heat Exchangers

The pilot-scale SFS includes four tube-and-shell heat exchangers for heat recovery and flue gas temperature control and two water-cooled heat exchangers to reduce the heat load on system fans. Their location in the overall process layout is illustrated in Figure 3-1. The first two tube-and-shell heat exchangers reduce flue gas temperature and preheat the secondary air for the main burner. The third and fourth tube-and-shell heat exchangers are used to control flue gas temperature at the inlet of the baghouse. Construction materials for the tube-and-shell heat exchangers are a combination of 304 stainless and carbon steels.

The main burner secondary combustion air temperature is nominally 600° to 800°F (316° to 427°C), depending on ambient air temperatures. During winter months, the secondary air temperature can be controlled at the lower end of the range, and during summer months, temperature control is limited to the higher end of the range. Two water-cooled heat exchangers are used to reduce the load on three SFS fans and ambient temperature on the upper levels of the SFS support

structure. One water-cooled heat exchange tube bundle is installed in the flue gas stream between the five process air heater tube bundles and the first tube-and-shell heat exchanger. This water-cooled tube bundle reduces the cooling load on the fans supporting the tube-and-shell heat exchangers. The second water-jacketed heat exchanger is installed on the secondary air bypass line to the stack and is designed to reduce the air volume entering the stack and the amount of heat being emitted to the immediate area.

3.1.6 System Fans

The pilot-scale SFS has five fans: a combustion air FD fan, two cooling-air FD fans, an induced-draft (ID) fan, and a flue gas recirculating (FGR) fan. Table 3-2 summarizes the fan specifications. For this test, only four of the fans were used. The smaller of the two cooling-air FD fans is used in support of the HTHX that was removed for this project.

All five fans are centrifugal-type fans, with variable-speed drives (speed controllers) installed on the four large fans. The combustion air FD blower supplies ambient air to tube-and-shell heat exchanger Nos. 1 and 2, plus combustion air to the auxiliary burner. A portion of the heated air exiting the heat exchangers is used as secondary combustion air to the main burner, with the rest exiting the system through the stack. Valves, orifice plates, and venturis are used to control and measure the air and flue gas flow in the SFS.

Final cooling of the flue gas before it enters the dry ESP or baghouse is provided by the larger of the two cooling-air blowers. This fan supplies ambient air to tube-and-shell heat exchanger Nos. 3 and 4. The heated air leaving the heat exchangers exits the system through the stack. An electronic speed controller on the fan is used to adjust the airflow from 0 to 1200 scfm (0 to 34 m³/min) to maintain a desired flue gas temperature entering the dry ESP or baghouse. This approach permits

Table 3-2. Pressure, Temperature, and Flow Specifications for SFS Blowers

	FD Blower	Cooling-Air Blower	ID Blower	FGR Blower	Cooling-Air Blower
Inlet Pressure, psig	0	0	1	0	0
Exit Pressure, psig	3	1.5	0.5	1.5	2
Avg. Inlet Temp., °F	60	60	350	350	80
Min. Inlet Temp., °F	20	20	250	250	60
Max. Inlet Temp., °F	100	100	450	450	100
Max. Inlet Flow, scfm	1200	1200	1200	450	200
Max. Inlet Flow, acfm	1292	1292	2255	788	200
Avg. Inlet Flow, acfm	1200	1200	1755	701	200
Motor Horsepower	40	20	25	10	5

particulate control device operation at either cold-side (350°F, 177°C) or hot-side (650°F, 344°C) conditions. However, for this project, the cooling-air blower was not needed to achieve the desired flue gas temperatures at the inlet to the dry ESP.

Flue gas exiting the wet ESP was drawn through the ID blower and discharged through the stack. The blower speed is regulated with an electronic speed controller to maintain a zero-pressure balance point in the slagging furnace. Normally, a portion of the hot flue gas (nominally 350°F, 177°C) from the ID fan exit is drawn through the FGR blower for use as dilution gas in the dilution/quench zone. However, as previously stated, FGR was not used while the SFS was operated in support of this project.

3.1.7 Emission Control

A pulse-jet baghouse is generally used for fine particulate control in the pilot-scale SFS. However, during this project, the pulse-jet baghouse was only used during heatup and cooldown of the SFS and when it was necessary to bypass the dry ESP, NH₃-based absorber, and wet ESP. Therefore, the pulse-jet baghouse is not discussed in this report.

Prior to this project, the SFS did not have a sulfur dioxide (SO₂) control system. Dispersion modeling data developed by the North Dakota Department of Health indicate that the stack dimensions (height and diameter) and volumetric flow rate allow a 20.8-lb/hr (9.4-kg/hr) sulfur dioxide emission rate to avoid potentially exceeding the ambient air standard. Based on operating experience with bituminous, subbituminous, and lignite fuels, the EERC has never exceeded a sulfur dioxide emission rate of 17 lb/hr (7.7 kg/hr). Emission of nitrogen oxides (NO_x) has been 1.4 lb/MMBtu or less (<650 ppm at 3% oxygen in the flue gas) for all tests conducted to date.

Additional flue gas sample ports were installed in the inlet and outlet piping of each of the three pollution control devices to permit flue gas sampling for gaseous/vapor-phase constituents as well as fly ash. Detailed descriptions of the three major pieces of air pollution control equipments used for these pilot-scale tests, the MET NH₃-based SO₂ adsorber, the dry ESP, and the wet ESP, are presented in Sections 3.2, 3.3, and 3.4 of this report, respectively.

Originally, flue gas filters and heat trace lines were installed to support three sample locations. The first location was at the exit of the slag screen; the second was upstream of the baghouse; and the third was downstream of the baghouse. As was the case with this project, these sample lines can be relocated, or additional sample ports can be added to the SFS. Using on-line instruments, specific routine flue gas measurements are made for carbon monoxide (CO), carbon dioxide (CO₂), oxygen (O₂), SO₂, and NO_x concentrations. Fly ash particle-size distribution (PSD) and mass loading and the concentrations of other flue gas constituents of interest are determined periodically using standard sampling techniques that are described in Section 4 of this report.

3.1.8 Instrumentation and Data Acquisition

The instrumentation and data acquisition components for the pilot-scale SFS measure and record combustion air, flue gas, process air, cooling water, temperatures, static and differential pressures, and flow rates. Flue gas is simultaneously monitored at two locations for O₂, SO₂, CO,

CO₂, and NO_x (nitric oxide and nitrogen dioxide) on a continuous basis using two sets of on-line analyzers. For this project, these two sets of flue gas analyzers were used to monitor the inlet of the dry ESP and the outlet of the wet ESP, respectively. Additional gas analyzers were used to simultaneously monitor O₂ levels at the inlet and outlet of the NH₃-based FGD. Numerous temperature measurements were made throughout the SFS to document flue gas, heat exchanger, and refractory conditions in the system. Orifice plates and venturis (monitored with pressure transducers and gauges on the main control panel) were installed to measure combustion airflow rate, flue gas flow rate, and process airflow rates.

The data acquisition system uses three personal computers with battery backup power supplies and is based on a Genesis software package. All process data points are logged on the data acquisition system and stored. Integrated process control has been implemented extensively throughout the SFS, although all system processes can also be controlled manually. The integrated process control includes the 1) fuel feed system, 2) furnace static pressure, 3) drawdown gas flow control, 4) combustion airflow control, 5) cooling-airflow control to the tube-and-shell heat exchangers, 6) process airflow rate and temperature control to the CAH tube bank, 7) process airflow rate and temperature control to the HTHX, 8) FGR rate to the dilution/quench zone, and 9) baghouse cleaning and temperature control. In addition to the data acquisition system, process data are recorded manually on data sheets on an established time schedule for backup purposes. Process control related to the dry ESP, NH₃-based FGD system, and wet ESP was generally a manual operation, as these components have not been integrated into the SFS's computerized process control functions.

3.2 Dry Electrostatic Precipitator

An ESP, designed and fabricated by MET, was installed on the SFS to reduce the quantity of fly ash reaching the MET NH₃-based FGD. MET designed and fabricated the pilot-scale ESP to simulate a commercial unit. During assembly and installation, the EERC added ash hoppers with knife valves and insulation to minimize heat losses. To reduce air in-leakage and heat losses, the EERC removed the original electrical conduits and modified the electrical connections. The two photographs in Figure 3-4 show the ESP following its assembly, installation of support piping, and the addition of fiberglass insulation. In the direction of the gas path, the internal geometry of the ESP is relatively tall and narrow with a nominal cross section of 40 in. (102 cm) high by 10 in. (25 cm) wide. The ESP has two electrical fields in series with a single ash hopper supporting each field.

The ESP was designed to operate at cold-side (250° to 400°F, 121° to 205°C) conditions. However, with some piping modifications and if flue gas flow rates are controlled in an appropriate range, the ESP could be operated as a hot-side (600° to 700°F, 316° to 371°C) unit. The ESP walls and ash hoppers are not electrically heated. Therefore, some condensation occurs upon initiating flue gas flow through the pilot-scale ESP. Once thermal stability was achieved, the differential temperature across the ESP was nominally 30° to 50°F (17° to 28°C). If the pilot-scale ESP were to be used extensively, it would be desirable to install electrical heaters on the exterior walls of the main chamber as well as the ash hoppers to improve temperature control and to minimize heat loss and avoid condensation on start-up and shutdown. Also, additional steps would be taken to reduce

Figure 3-4. Photographs showing the dry ESP following its assembly, installation of support piping (top), and the addition of insulation (bottom).

air leakage. Inlet and outlet piping are insulated but not heat-traced. Materials of construction for the ESP are carbon steel. Flue gas inlet and outlet piping are 6-in. (15-cm)-i.d. Schedule 10 304L stainless steel.

Flue gas flow rates to the ESP ranged from a low of 425 scfm ($12.0 \text{ m}^3/\text{min}$) to a maximum of 550 scfm ($15.6 \text{ m}^3/\text{min}$). The ESP collection area totals nominally 58 ft^2 (5.4 m^2), 29 ft^2 (2.7 m^2) in each field. Each field consists of two parallel plates with nominal dimensions of 40 in. (102 cm) by 52.5 in. (133 cm) and a 10-in. (25-cm) nominal plate spacing. Six weighted-wire electrodes support each field. Electrode spacing alternates between 8 and 10 in. (20 and 25 cm) in each field along the gas path, and the electrodes are centered between the plates. For the pilot-scale tests, the calculated specific collection area (SCA), based on flue gas flow rates and collection plate area, ranged from 67 to $89 \text{ ft}^2/1000 \text{ acfm}$ (6.1 to $8.2 \text{ m}^2/28 \text{ m}^3/\text{min}$).

Each plate is secured to a rigid support structure on top and allowed to hang in a guided position, permitting the plates to move to some degree during rapping. The weighted-wire electrodes are hung from hooks on a rigid frame. The spacing between the plates and wires was nominally 5 in. (13 cm). The ESP is a single chamber, but effectively two compartments, one for each of the two fields. Plate rapping was done manually on a predetermined interval either on- or off-line. If the ESP were to be used on a more frequent basis, it would be desirable to install pneumatic rappers that could be actuated and controlled on-line using the existing SFS process control software. Access to the plates, wires, insulators, and electrical connections is gained by removing the roof plate of the ESP, with some limited side panel access also available.

Each ESP field is supported by an individual power supply and controller. The power supplies and controllers were purchased from HIPOTRONICS, Inc., and have a capacity of 0 to 75 kV and 0 to 75 mA. Power input to each field is manually set, and the power supplies will trip as a result of a spark event. If a power supply trips, it must be manually reset. Operating experience to date has resulted in current levels of 0.3 to 3.6 mA and voltages of 34 to 47 kV to the first field and 0.3 to 30 mA and 35 to 50 kV to the second field. Current levels in the second field that were $>10 \text{ mA}$ were achieved during test periods when flue gas humidification was used upstream of the ESP. Figure 3-5 is a photograph of the four power supplies originally purchased to support the dry and wet ESPs.

Thermocouples were installed in the inlet and outlet piping transitions to monitor ESP flue gas temperature. Differential pressure across the ESP and static pressure at the outlet of the ESP were monitored continuously with gauges. ESP thermocouple data were automatically logged on the data acquisition system. Differential and static pressure as well as temperature data were recorded manually on data sheets on a periodic basis. If the ESP were to be used on a more frequent basis, it would be desirable to install pressure transducers to permit differential pressure and static pressure data to be logged automatically by the data acquisition system.

ESP ash removal was accomplished by opening a 6-in. (15.2-cm) knife valve at the bottom of each hopper, allowing ash material to drain through a 6-in. (15.2-cm) stainless steel pipe into a 55-gal (208-L) drum on the main floor level. Ash containers of this size facilitate handling and are adequate for ash accumulation during 100-hr and longer test periods, with only periodic replacement required.

Figure 3-5. Photograph of the four power supplies originally purchased to support the dry and wet ESPs.

Flue gas sample ports were installed in the inlet and outlet piping of the ESP to permit flue gas sampling for gaseous/vapor-phase constituents as well as fly ash. There are no sight ports installed in the dry ESP.

3.3 Description of the MET NH_3 -Based FGD Scrubber

A schematic and photograph of the pilot-scale MET scrubber installed at the EERC is shown in Figures 3-6 and 3-7. As can be seen, the hot flue gas exiting from the dry ESP was contacted in an absorber tower with a recirculating spray of subsaturated ammonium sulfate liquor. As the primary control loop for the MET NH_3 -based FGD system, ammonia was added to a holding tank with the oxidation air to maintain the recycle liquor at a pH of 5.5 to 5.7, the optimum pH to ensure low levels of sulfite formation. The ammonia system is completely automated using an in-line pH meter. Once the flue gas was cleaned, it was then passed through two high-efficiency mist eliminators to remove any entrained droplets. The thermal energy of the flue gas was used to evaporate water in the tower as the flue gas reached the saturation point. The evaporation of water resulted in crystallization of ammonium sulfate product.

Figure 3-6. Schematic of MET NH_3 -based FGD system.

Figure 3-7. Photograph of MET NH_3 -based FGD.

Slurry was periodically bled from the tank to a dewatering system, increasing the slurry density from 10–35 wt%. This slurry was composed of ammonium sulfate, water, and the small amount of fly ash particles that was not collected by the dry ESP. In a full-scale system, a hydroclone is used to dewater the slurry as well as to remove any fly ash particles entrained in the slurry. Although a small hydroclone was used in the pilot-scale NH₃-based FGD, no attempt was made to separate the ammonium sulfate product and the fly ash.

The process chemistry of the production of ammonium sulfate from boiler flue gas is very similar to the chemistry of a limestone-based reagent. The process chemistry is shown by the following reactions:

All of these reactions take place in the absorber vessel in the soluble phase. As stated earlier, the ammonium sulfate is recovered through crystallization when the excess water is evaporated. A more detailed explanation of the process as it is used at the Dakota Gasification facility is provided in a paper presented at the 1999 EPRI–DOE–EPA combined Utility MEGA Symposium (2).

3.4 Wet Electrostatic Precipitator

A wet ESP, designed and fabricated by Environmental Elements Corporation (EEC), was installed on the SFS to control aerosol and particulate emissions following the MET NH₃-based FGD system (shown schematically in Figure 3-8). The EERC assembled and installed the unit, adding wash water hoppers with appropriate discharge piping and valves, electrical heaters, and insulation to the exterior surface to minimize heat losses. The photograph in Figure 3-9 shows the wet ESP following its assembly, installation of support piping, and the addition of fiberglass insulation. In the direction of the vertical gas path, the geometry of the wet ESP is square with a relative cross section of 12 × 12 in. (30 × 30 cm). The ESP has two electrical fields in series with separate wash water hoppers supporting each field. Each field has separate wash water valves and two spray nozzles per field.

The wet ESP design was based on operation at condensing flue gas temperatures (nominally 130°F/55°C). Originally, the ESP walls were electrically heated. However, during shakedown, flue gas temperatures were observed to increase across the wet ESP by nominally 5° to 10°F (3° to 6°C).

Figure 3-8. Schematic of the wet ESP.

Figure 3-9. Photograph showing the wet ESP following its assembly, installation of support piping, and the addition of insulation.

Therefore, for this project, the electrical heaters on the chamber walls were turned off. With the heaters off and thermal stability achieved, the differential temperature across the ESP was $<2^{\circ}\text{F}$ ($<1^{\circ}\text{C}$). Inlet and outlet piping were insulated and electrically heat-traced to minimize wall condensation. Materials of construction for the wet ESP were made of 316 stainless steel. Flue gas inlet and outlet piping were made of 304L stainless steel. Because of the small cross-sectional area of the wet ESP chamber, no internal supports were required.

During testing, flue gas flow rates to the wet ESP ranged from a low of 480 scfm ($13.6\text{ m}^3/\text{min}$) to a maximum of 595 scfm ($16.8\text{ m}^3/\text{min}$). The wet ESP collection area is nominally 64 ft^2 (5.9 m^2), 32 ft^2 (3.0 m^2) in each field. Each field consists of a square duct with dimensions of 12 in. (30.5 cm) by 12 in. (30.5 cm) and a length of 8 ft (2.4 m). A single mast electrode supports each field. Calculated SCA, based on flue gas flow rates and collection area, ranged from 91 to $112\text{ ft}^2/1000\text{ acfm}$ (8.3 to $10.2\text{ m}^2/28\text{ m}^3/\text{min}$).

The internal shell surface of each chamber is the collecting plate with a spiked rigid mast electrode centered in each chamber and secured at the top. Details concerning the mast electrode are proprietary to EEC. The wet ESP has two vertically oriented compartments in series separated by a short crossover duct. Water washing is done manually, off-line on a predetermined interval. If the wet ESP were to be used on a more frequent basis, it would be desirable to install control valves for flue gas flow and wash water that could be actuated and controlled on-line using the existing SFS process control software. Access to the rigid mast electrodes is gained by removing the insulating crocks on top and access doors near the bottom of each chamber. Electrical connections are external to the chamber with access gained by removing the insulating crocks on top of each chamber.

Each wet ESP field is supported by an individual power supply and analog controller. As was the case for the dry ESP, the original power supplies and controllers were purchased from HIPOTRONICS, Inc., and have a capacity of 0 to 100 kV and 0 to 10 mA. Power input to each field is manually set, and the power supplies will trip as a result of a spark event. If a power supply trips, it must be manually reset. Operating experience to date has resulted in current levels of 0.2 to 5.3 mA and voltages of 32 to 56 kV to the first field and 0.3 to 18 mA and 37 to 52 kV to the second field. Current levels $>2\text{ mA}$ in the first field were achieved during test periods when flue gas humidification was used upstream of the dry ESP.

Thermocouples and pressure gauges were used to monitor flue gas temperature and differential and static pressure, respectively. The temperatures were automatically recorded by the data acquisition system.

Wet ESP wash water and entrained ash and aerosols are discharged from the bottom hopper areas through 2-in. (5-cm) PVC (polyvinyl chloride) ball valves at the bottom of each hopper and recycled back to the scrubber through 2-in. (5-cm) PVC pipe. This approach permitted the collection of liquid samples yet minimized personnel exposure to this process stream.

Flue gas sample ports were installed in the inlet and outlet piping of the wet ESP as well as the crossover duct to permit flue gas sampling for gaseous/vapor-phase constituents as well as fly ash. Aerosol and fly ash PSD and mass loading are determined periodically using standard methods. No sight ports were installed in the wet ESP.

Between the April and July 2001 test periods, several modifications were made to the wet ESP. The first change involved the installation of a distributor plate in the inlet of the first field. Fabrication of the distributor plate was accomplished using 18 gauge 304 stainless steel with an open area of 33%. Hole diameter was 0.094 in. (0.239 cm). The purpose of this modification was to ensure more uniform flow distribution across the field, minimizing the potential for gas sneakage along the electrode mast. Although there was concern about the potential for deposition and plugging, this did not occur during the subsequent tests.

The second modification made to the wet ESP was to replace the two 8-ft (2.4-m) electrode masts originally designed and fabricated by EEC with a 4-ft (1.2-m) mast in the first field and a 12-ft (3.6-m) mast in the second field. Installation of a longer electrode mast in the second field also required adding 4 ft (1.2 m) to the length of the chamber and modifying outlet piping. The photograph in Figure 3-10 shows the wet ESP following the modifications. Total effective collection area did not change as a result of the modifications. However, collection area distribution between the fields changed significantly. Collection area in the first field was reduced to 16-ft² (1.5 m²) and increased to 48-ft² (4.5 m²) in the second field. Other changes to the electrode masts resulted in an overall increase in power input to each field and the ability to increase current levels for any given voltage. As stated earlier, details concerning the electrode mast design are considered proprietary to EEC.

The final change involved replacing both of the HIPOTRONICS, Inc., power supplies and controllers supporting the wet ESP in an attempt to increase power input to both fields. For the first field, the HIPOTRONICS, Inc., power supply and analog controller were replaced with an electronic Spellman power supply and controller the EERC had available from another project. The capacity of the Spellman power supply is 0 to 10 mA and 0 to 100 kV. The advantage of the electronic power supply was that a spark rate could be set, and sparking events were handled by the electronic controller, eliminating the need to manually reset the power supply. For the second field of the wet ESP, the power supply and controller were switched with one of the power supplies and controller originally used on the dry ESP. This change was made to increase the potential current input from 0 to 10 to 0 to 75 mA. As a result of these changes, the performance of the wet ESP improved significantly for the tests conducted in July 2001. Details concerning improved wet ESP performance are discussed later in this report.

4.0 MEASUREMENT AND SAMPLING PROCEDURES

The following flue gas constituents were measured during the pilot- and/or full-scale tests:

- SO₂
- CO₂
- NO_x
- CO
- O₂
- SO₃
- NH₃
- Chlorides
- Particulate matter
- Hg

Figure 3-10. Photograph of the wet ESP following the modifications.

It should be noted that all EPA methods discussed below can be found on the EPA web site at <http://www.epa.gov/ttn/emc>. Table 4-1 outlines the sampling and analytical methods used for the emissions sampling.

4.1 SO₂, CO₂, NO_x, CO, and O₂ Concentrations

During the pilot-scale tests, the EERC continuously monitored O₂ at four sample points (inlet and outlet of the dry ESP, outlet of the MET NH₃-based scrubber, and the outlet of the wet ESP). SO₂, NO_x, CO, and CO₂ were monitored continuously at the combustor exit and the wet ESP outlet. The concentration values from all of the instruments were recorded continuously on a data-logging system. In addition, data were manually recorded at set time intervals. The instrumentation used for each of these gases is shown in Table 4-2. Each of these analyzers was regularly calibrated using certified calibration gases in the expected measurement range and were maintained to provide accurate flue gas concentration measurements.

Table 4-1. Sampling and Analytical Methods Used for the Test Program

Gas Constituent	Method
Particulate Concentration	EPA Method 5/17
Near Real-Time PSD	aerodynamic particle sizer (APS)/scanning mobility particle sizer (SMPS)
Size-Segregated Fly Ash Samples	Multicyclone
Bulk PSD	Malvern analyzer
Ammonia to the MET Scrubber	Calibrated flowmeter and mass flow controller
Ammonia Slip	EPA Method 27 with ion chromatography
SO ₃	Selective condensation and ion chromatography
Chlorides (HCl/Cl ₂)	EPA Method 26A and ion chromatography
Mercury	Ontario Hydro Mercury Speciation Method and CVAA (cold-vapor atomic adsorption)
pH	pH meter paper
Specific Density	Gravimetric determination
Nitrites	Ion chromatography
Major Elements (fly ash and coal)	X-ray fluorescence (XRF)
Minor Elements (fly ash)	Mass spectroscopy

Table 4-2. Measurement Methods for Continuously Measured Flue Gas Constituents

Gas	Company	Measurement Method
SO ₂	Ametek	UV (ultraviolet) photometric
CO ₂	Rosemount	Nondispersive infrared (IR)
NO _x	Thermo Environmental	Chemiluminescence
CO	Rosemount	Nondispersive IR
O ₂	Rosemount	Paramagnetic detection

4.2 Chlorine, SO₃, and Ammonia

To measure the concentration of chlorides in the flue gas, EPA Method 26A was used. This method was originally developed to measure both HCl and Cl₂ concentrations in the flue gas. During sampling, the separation of the halides (HCl) from the halogens (Cl₂) is accomplished physically within the impinger matrices. Cl₂ exhibits a low solubility in acid solutions (0.1N H₂SO₄), but is collected effectively in basic solutions (0.1 N NaOH). The HCl, on the other hand, is captured effectively by the 0.1 N H₂SO₄ solution. The impinger train is operated similarly to other sampling procedures such as EPA Method 5 or 17. Since the gaseous phase chlorides are not impacted by gas flow or isokinetic sampling rate, the sampling was operated at a constant flow from a single point. It has been found that in the presence of SO₂ the method does not accurately speciate chlorides (3); however, the method still gives an accurate measurement of total chlorides. Once the chlorides were adsorbed in the solutions, they were analyzed using ion chromatography techniques.

For SO₃ measurements, the controlled condensation technique was used. This method uses a water bath to control the temperature in a condenser at 142°F (61°C). At this temperature, the SO₃ condenses and is retained on a glass wool plug and on the inside of the condenser. The SO₂ and water vapor continue on through the condenser in the gaseous state. Once the gas has passed through the condenser, it is passed through two impingers containing a hydrogen peroxide solution in which the SO₂ is absorbed. A schematic of the selective condensation system is shown in Figure 4-1. Sampling data, recorded at a regular interval during the tests, included probe temperature, condenser temperature, stack temperature, flowmeter readings, gas meter temperatures, system pressures, barometric pressure, and sampling time period. After completing the sampling, a leak check was carried out for the probe, and the condenser was rinsed using DI water to recover the condensed SO₃ for analysis by ion chromatography.

For ammonia analyses, conditional EPA Method 27 was used. This is, again, a modification of EPA Method 5/17. The two water impingers used in EPA Method 5/17 are replaced with 0.1 N sulfuric acid solution, which adsorbs the ammonia. The ammonia concentration in the impinger solutions was measured using ion chromatography.

For the pilot-scale tests, the ammonia injected into the MET scrubber was based on a pH control set point recommended by MET. The ammonia was metered from an anhydrous ammonia

effectively provides a size distribution for particles ranging from 0.7 to 15 μm . The PSD can be obtained either on a number or mass basis depending on whether the particle density is known or can be estimated.

4.3.2 Scanning Mobility Particle Sizer

To determine the concentration of submicron particles, 0.03 to 1.0 μm , a SMPS was used. The SMPS system consists of two primary sections: an electrostatic classifier and a condensation particle counter (CPC). The purpose of the electrostatic classifier is to remove a predictable fraction of the particles within a narrow size range and pass these on to the CPC where the particles are counted. The electrostatic classifier is based on a Boltzmann distribution of electric charge (gas is first passed through a krypton-80 beta source). The CPC measures particle number concentration by using the light-scattering technique. Since the dry submicron particles are too small to be easily detected by light scattering, the particles pass through an alcohol vapor that condenses on the particles, forming a droplet. Each droplet is large enough to scatter a detectable amount of light when it passes through a light beam.

4.4 Mercury

Although mercury concentration was not a major component of the overall project, it was measured in both the flue gas and in the liquid and solid material generated in the pilot-scale tests. The method used to measure mercury in the flue gas was the Ontario Hydro mercury speciation method. This method is a modification of EPA Method 5/17 where a series of impingers are used to separate the species of mercury in the flue gas (elemental mercury and oxidized mercury). The impinger solutions are then analyzed using CVAA techniques. A detailed description of the method is provided at the following web site: <http://www.epa.gov/ttn/emc/prelim.html>.

4.5 Fuel, Fly Ash, Scrubber Liquor, and Ammonia Sulfate Solids

The following analyses were performed on the composite fuel samples and the fly ash collected from the ESP hoppers. Most of the methods used for these measurements are standard techniques as defined by the American Society for Testing and Materials (ASTM) or EPA. Also shown below are the analyses done on the liquor collected from the pilot-scale MET ammonia based SO_2 scrubber and the resultant ammonium sulfate by-product.

4.5.1 Fly Ash

- Loss on ignition (LOI)
- Carbon content (CHN analysis)
- XRF (major elements and some trace elements)
- Malvern (bulk PSD)

4.5.2 Fuel

- Mercury
- Chlorides
- Ultimate/proximate
- Btu
- XRF (major and some trace elements)
- Sieve analysis (size distribution)

4.5.3 Scrubber Liquor and Ammonium Sulfate Solids

- Specific gravity
- pH
- Nitrates/nitrites
- Mercury
- Chlorides
- Mass spectroscopy (trace elements)

5.0 TECHNICAL APPROACH

The pilot-scale tests consisted of 3 weeks of testing. The first week was shakedown of the installed equipment. The second week (referred to as Test Series I) was to evaluate the effectiveness of the wet ESP to remove fine particles/SO₃ aerosols from the flue gas stream. The third week (Test Series II) was to complete a parametric evaluation of particulate removal efficiency of the wet ESP after modifications had been made to improve the overall electric field characteristics of the unit.

5.1 Shakedown

Installation and shakedown of the equipment were completed in the first week of testing. The dry ESP was manufactured by MET and then shipped to the EERC; the MET NH₃-based FGD system was originally located in at the Winyah Station in South Carolina and had to be dismantled prior to shipping to the EERC. The wet ESP was manufactured by EEC. The three components were installed in the high-bay area of EERC's Building X adjacent to the SFS. Installation included assembling the three new pieces of equipment and the piping necessary so that they could be used with the SFS. In addition, sampling ports were installed so that all necessary sampling could be accomplished in an efficient manner. Table 5-1 lists the sampling point locations for the pilot-scale tests. Because a blended fuel was used, a second feed system was installed on the SFS. The already existing primary feeder, described previously, was used to feed the coal. The second feeder was used to feed the petroleum coke simultaneously with the coal. The modifications made to each of the three new pieces of equipment were discussed in Section 3 of this report.

Following installation of the equipment, the anhydrous ammonia tank was connected and checked to verify that there were no leaks and the delivery system worked properly. Also, during the initial shakedown period, ammonium sulfate and ammonium chloride were added to the MET scrubber tank. Enough ammonium sulfate was added to the water so that the solution was near

Table 5-1. Sampling Point Locations

Sampling Point No.	Sampling Point Location
–	Outlet of the combustor
1	Inlet of the dry ESP
2	Outlet of the dry ESP/inlet of the MET FGD
3	Outlet of the MET FGD/inlet of the wet ESP
4	Outlet of the wet ESP

saturation (specific density of 1.23). Ammonia chloride was added such that the chloride level in the tank was about 10,000 ppm.

Once installation of the dry ESP, MET scrubber, and wet ESP was completed, and the ammonium sulfate/chloride had been added, a 1-week shakedown test was performed. The shakedown test had two primary purposes: first, to ensure all components of the system (SFS combustor, dry ESP, MET scrubber, and wet ESP) were working properly; secondly, to characterize the particulate matter (concentration and PSD) entering the MET scrubber. To determine the overall dust loading, EPA Method 5/17 was completed at the inlet and outlet of the dry ESP (Sample Points 2 and 3). The PSD was also determined using the APS/SMPS. Also, as part of the shakedown testing, flue gas SO₃ concentrations were measured at Sample Points 2 and 3.

During the shakedown tests, fuel and ash samples from the dry ESP were collected for characterization. Ultimate/proximate analysis, particle size after pulverizing, and XRF were completed to document the fuel properties. Ash samples from the dry ESP were taken and analyzed for carbon content to verify that combustor burner settings were appropriate for the fuel fired.

5.2 Characterization of Emissions from the Dry ESP, MET Scrubber, and Wet ESP – Test Series I

Immediately following completion of the shakedown tests, a 6-day pilot-scale test was conducted to document the performance of the dry ESP, MET NH₃-based FGD system, and wet ESP. The entire test was conducted using an 80–20 wt% blend of Robinson Run eastern bituminous coal and a petroleum coke. As can be seen in Table 5-2, several test parameters had to be determined during the test. After the first day of testing, plugging occurred in the CAH (convective air heater) because of ash accumulation. This resulted in very high pressures throughout the entire system. Therefore, for the remainder of the weeklong effort (both Series I and II), the SFS was fired on natural gas at night to maintain temperature and the CAH was cleaned on-line. This resulted in approximately 8 to 10 hours of coal/petcoke firing for each day of testing.

The original sampling plan that was to be completed for Test Series I is shown in Table 5-3. However, after the first several days of testing, it was shown that the vapor-phase SO₃ levels after the MET NH₃-based FGD system were at or near zero. Therefore, the selective condensation sampling was discontinued at Sample Points 3 and 4.

Table 5-2. SFS Test Parameters for Test Series I

Parameter	Set Point
Coal–Petcoke	Robinson Run–petcoke (80–20 wt% blend)
Furnace Temperature	2000° to 2400°F
Furnace Exit Pressure	Set to maintain –0.2 in. H ₂ O in furnace
CAH Flue Gas Inlet Temperature	≤1800°F ± 100°F
SCA Temperature	≥400°F
Dry ESP Inlet Temperature	300° to 320°F
Dry ESP Inlet Flow Rate	500 scfm
Dry ESP Power Settings	To be determined
O ₂ in Flue Gas at Dry ESP Inlet	4 vol% O ₂
O ₂ in Flue Gas at Furnace Exit	3.5 ± 0.5% (~20% excess air)
Main Burner Prim./Sec. Air Split	15%/85% @ 1.20 A/F ratio
CAH Process Air Inlet Temp.	1000°F ± 100°F @ 100 scfm ± 20scfm
CAH Process Air Outlet Temp.	≤1300°F
Heat Exchanger B No. 2–5 Outlet Air Temp.	1275°F ± 50°F
Wet ESP Inlet Temperature	130° to 135°F
Wet ESP Power Settings	To be determined
Wet ESP Wash Frequency/Volume	To be determined
Process Air Reheat Flow Rate	To be determined (60 scfm or less)
Process Air Reheat Temperature	To be determined (500° to 600°F)

Table 5-3. Sampling Activities for Test Series I

Sample Point	SO ₃	NH ₃	Chlorides	Method 5/17	Multi-cyclone	APS/SMPS
–	2			2		1
1	3		3	3	3	
2	5		5	5		3
3	5	5	5	5		2
4	5	5	5	5		3

5.3 Characterization of Emissions from the Dry ESP, MET Scrubber, and Wet ESP – Test Series II

The primary objective of Test Series II was essentially the same as Test Series I, which is to evaluate the performance of the wet ESP with respect to the control of aerosol/particulate emissions from the NH₃-based FGD system. The performance target for the wet ESP was a particulate mass collection efficiency of >90% in order to ensure a stack opacity of <10%. As was stated in Section 3.4, prior to doing Test Series II, the EERC installed a new set of electrodes that were designed by EEC to provide better overall performance. Selection of the new electrodes was based on an evaluation of four different electrode types. Cold-flow tests were completed by the EERC generating voltage/amperage

data for the first field of the wet ESP for each of the different masts. Based on these data, EEC selected the new electrodes to be used for Test Series II.

As part of Test Series II, the EERC installed a flue gas humidification system upstream of the dry ESP. The humidification system used pressurized water and air in a dual-fluid nozzle. The humidification system was operated at a flow rate of 4–5 gal/hr (15.14–18.93 L/min) water. This rate dropped the flue gas temperature from about 360°F to about 280°F (182° to 138°C).

In order to permit evaluation of wet ESP performance based on variations in SO₃ concentration at the inlet of the MET NH₃-based FGD system, the tests were conducted with different coal-to-petroleum coke ratios. Also, one test was conducted where the velocity of the flue gas was increased through the wet ESP from 9 ft/s (3.05 m/s) to 10 ft/sec (3.35 m/s). This test was to help determine the size limitations of the wet ESP for a full-scale installation. The variables for Test Series II are shown in Table 5-4, and the SFS parameters are shown in Table 5-5. A key operating parameter was the flue gas flow rate at the inlet of the wet ESP. In order to achieve a velocity of 9 ft/s (2.74 m/s), the required flow rate was 540 acfm (15.29 m³/min) at 130°F (54°C). This corresponds to a flow rate at the inlet of the MET NH₃-based FGD system of nominally 640 acfm (18.12 m³/min) at 320°F (160°C). As was the case for Test Series I, the SFS was operated on natural gas at night, and the CAH was cleaned out to prevent excess pressure buildup in the system.

Extensive sampling was completed for the 6 days in order to complete the wet ESP performance evaluation. The sampling plan for Test Series II is shown in Table 5-6.

6.0 RESULTS AND DISCUSSION

6.1 Characterization of Emissions from the Dry ESP, MET Scrubber, and Wet ESP – Pilot-Scale Test Series I

Test Series I was a weeklong test beginning April 23, 2001, and continuing through April 28, 2001. The coal fired in the SFS was a Robinson Run eastern bituminous coal blended with 20% petroleum coke.

Table 5-4. Variables for Test Series II

Test No.	Humidification	Petroleum Coke, wt% ¹	Gas Velocity Through Wet ESP, ft/sec
1	No	None	9
2	No	20	9
3	No	30	9
4	Yes	20	9
5	Yes	30	9
6	No	20	10

¹ The coal was a Robinson Run eastern bituminous coal.

Table 5-5. SFS Test Parameters for Test Series II

Parameter	Set Point
Coal/Petcoke	Robinson Run/petcoke
Furnace Temperature	2200° to 2600°F
Furnace Exit Pressure	Set to maintain –0.2 in. H ₂ O in furnace
CAH FG Inlet Temperature	≤1800°F ± 100°F
SCA Temperature	≥400°F
Dry ESP Inlet Temperature	350° to 400°F
Dry ESP Inlet Flow Rate	440 scfm
Dry ESP Power Settings	To be determined
O ₂ in Flue Gas at Dry ESP Inlet	6 vol% O ₂
O ₂ in Flue Gas at Furnace Exit	3.5 ± 0.5% (~20% excess air)
Main Burner PCA/SCA Split	70 scfm PCA/balance SCA @ 1.20 A/F
CAH Process Air Inlet Temp.	1000°F ±100°F @ 100 scfm ± 20 scfm
CAH Process Air Outlet Temp.	≤1300°F
Heat Exchanger B No. 2–5 Outlet Air Temp.	1275°F ± 50°F
Wet ESP Inlet Temperature	130° to 135°F
Wet ESP Power Settings	To be determined
Wet ESP Wash Frequency/Duration	Every 2 hr for 30 seconds
Process Air Reheat Flow Rate	100 scfm
Process Air Reheat Temperature	To be determined (500° to 600°F)

Table 5-6. Sampling Activities for Each of Six Test Conditions – Test Series II

Sample Point	SO ₃	NH ₃	Chlorides	Method 5/17	Multi-cyclone	APS/SMPS
1	2				1	
2	2		1	1		
3		1	1	1		1
4		1	1	1		1

6.1.1 Fuel Analyses

Proximate/ultimate and elemental analysis for the two fuels are presented in Table 6-1. Based on the analysis, the coal is typical of a high-sulfur eastern bituminous coal. Both the mercury and chlorine contents are about average for these types of fuels as well. The alkali content (CaO, MgO, Na₂O, and K₂O) of the coal ash is 8.05%. This is a somewhat higher than average for eastern bituminous coals, which are typically in the 4%–6% range. For example, an Illinois basin coal recently analyzed at the EERC had an alkali content of 5.85%. The alkali content is important as it can readily react with both SO₂ and SO₃, depending on the flue gas temperature.

Table 6-1. Analysis of Fuels Used for Test Series I, on a dry basis

	Robinson Run Bituminous Coal	Petroleum Coke
<i>Proximate Analysis, wt%</i>	<i>3 analyses</i>	<i>2 analyses</i>
Moisture Content	1.03	0.65
Volatile Matter	40.68	11.72
Fixed Carbon	44.36	86.5
Ash	14.95	1.14
<i>Ultimate Analysis, wt%</i>	<i>3 analyses</i>	<i>1 analysis</i>
Hydrogen	4.76	3.48
Carbon	70.49	86.0
Nitrogen	1.72	2.41
Sulfur	4.18	6.84
Oxygen, by difference	3.90	0.12
Heating Value, Btu/lb	12,704	14,944
<i>Ash Fusion Temperatures, °F</i>	<i>3 analyses</i>	<i>1 analysis</i>
Initial Temperature	2413	2324
Softening Temperature	2450	2484
Hemi. Temperature	2522	2343
Fluid Temperature	2565	2460
<i>Coal Analysis</i>	<i>2 analyses</i>	<i>1 analysis</i>
Mercury, µg/g	0.0807	0.0038
Chlorides, µg/g	508	<50
<i>Coal Ash Analysis, % conc. as oxides</i>	<i>2 analyses</i>	<i>1 analysis</i>
SiO ₂	46.4	46.1
Al ₂ O ₃	23.1	13.5
Fe ₂ O ₃	16.3	21.7
TiO ₂	0.91	1.01
P ₂ O ₅	0.17	0.27
CaO	3.38	4.99
MgO	1.80	2.95
Na ₂ O	1.02	2.12
K ₂ O	2.12	5.78
BaO	0.10	<0.02
MnO	0.03	<0.02
SrO	0.10	<0.02
SO ₃	4.41	1.51
<i>Coal Ash Analysis, mg/kg</i>	<i>2 analyses</i>	<i>1 analysis</i>
Cr	143	<100
Cu	<100	<100
Ni	<100	3.5%
V	173	21%
Zn	<103	180

Note: Ni and V values are for information only. Values reported are above the calibration range of the instrument.

The petroleum coke used for this test was obtained from an oil refinery in Louisiana. As can be seen in Table 6-1, the petroleum coke was high in sulfur and very low in ash. Although the ash content was very low, a high percentage is composed of vanadium and nickel compounds, which may help to convert SO₂ to SO₃.

6.1.2 Process Conditions

6.1.2.1 Fuel Feed Rates

The SFS is a pc-fired combustor or furnace; therefore, prior to the fuel being fed, it must be pulverized. The objective was to provide fuel that measured 70% <200 mesh (< 74 µm) based on a sieve analysis. The results showed that the coal was 62.5% <200 mesh (< 74 µm) and the petroleum coke was 65.1% <200 mesh (< 74 µm). The slighter larger fuel size was most likely a result of the coal being somewhat wet when it was received. However, the relatively low carbon content in the fly ash collected in the dry ESP indicated that good combustion efficiency occurred during the test. The LOI and ash carbon content for the dry ESP hopper ash is shown in Table 6-2. The actual carbon carryover was nominally 0.2 wt%.

Originally, it was intended that coal–petroleum coke would be fired in the SFS 24 hours/day. However, after the first day, plugging occurred in the CAH, and it was necessary to switch to natural gas to clean out the CAH. It was decided that the SFS would operate on coal–coke 8–10 hours per day and then switch to natural gas at night. The coal–coke feed rates and the flue gas flow rates for each day of testing are shown in Table 6-3.

6.1.2.2 Operational Data for the Two ESPs

The voltage and current data for both the wet and dry ESPs are shown in Table 6-4. What is clear from these data is the wet ESP generated a current that is much less than what was expected given the makeup of the flue gas and the size of the ESP. As will be discussed later in this report, the particulate removal efficiency of the wet ESP was also less than expected. As a result, alternative electrode designs were evaluated by EEC with the intent of increasing the current input to the wet ESP.

Table 6-2. Carbon Content of the Dry ESP Hopper Ash Samples Collected During Test Series I¹

Day	Field 1 LOI, wt%	Field 1 Ash Carbon, wt%	Field 2 LOI, wt%	Field 2 Ash Carbon, wt%
3	1.26	0.26	4.85	0.18
4	1.32	0.19	6.53	0.20
5	1.43	0.16	5.85	0.22
Average	1.34 ± 0.09	0.20 ± 0.05	5.74 ± 0.85	0.20 ± 0.02

¹Fuel fired during the entire test was 80% Robinson Run bituminous coal blended with 20% petroleum coke.

Table 6-3. Fuel Feed Rates for Test Series I

Test Period	Time, hr	Coal Feed Rate, lb/hr	Pet. Coke Feed Rate, lb/hr	Flue Gas ¹ Flow Rate, scfm	Flue Gas ² Flow Rate, scfm	Flue Gas Flow Rate, acfm
1	16.9	88	22.5	467.0	— ³	520
2	12.6	88	21.4	473.9	456.7	531
3	9.9	101	24.1	536.5	527.8	601
4	12.2	90	21.3	485.0	487.3	536
5	7.7	88	21.3	490.6	456.8	544

¹ Flue gas flow rate based on a venturi (inlet of NH₃-based FGD).

² Flue gas flow rate based on pitot reading (inlet of NH₃-based FGD).

³ Not available.

Table 6-4. Operational Data for the Two ESPs¹

Test Period	Wet ESP Voltage Field 1, kV	Wet ESP Current Field 1, mA	Wet ESP Voltage Field 2, kV	Wet ESP Current Field 2, mA	Dry ESP Voltage Field 1, kV	Dry ESP Current Field 1, mA	Dry ESP Voltage Field 2, kV	Dry ESP Current Field 2, mA
1	47.38	0.86	50.56	1.34	43.41	1.03	43.63	1.06
	3.14	0.26	2.09	0.58	2.30	0.43	1.58	0.32
2	38.23	0.56	43.35	0.82	34.54	0.49	34.85	0.41
	6.39	0.38	2.68	0.41	0.31	0.19	0.36	0.16
3	37.30	0.51	39.80	0.59	42.05	0.79	41.40	0.44
	2.76	0.32	2.23	0.53	0.72	0.14	0.80	0.10
4	41.43	0.51	46.43	0.94	44.90	0.91	39.50	0.56
	1.05	0.14	3.99	0.80	0.58	0.16	2.54	0.18
5	34.71	0.44	44.50	0.48	42.50	1.03	42.19	0.93
	1.16	0.10	1.12	0.47	0.71	0.23	0.35	0.20

¹ The first number is the average for the test period; the number directly below is the standard deviation.

6.1.2.3 Flue Gas Temperatures

The resultant flue gas temperatures at the inlet and outlet of each APCD are shown in Table 6-5. There was a fairly substantial temperature increase across the wet ESP for the first 3 days of testing. It was believed that this was causing the walls of the wet ESP to dry out, reducing the effectiveness of the unit. Therefore, for the last two test periods, all the heaters on the unit were turned off. This resulted in approximately the same inlet and outlet temperature.

Table 6-5. Flue Gas Temperatures for Test Series I

Test Period	Total Time, hr	Dry ESP In, °F	Dry ESP Out, °F	FGD In, °F	FGD Out, °F	Wet ESP In, °F	Wet ESP Out, °F
1	25.53	375±15	325±15	312±15	126±3	127±4	133±9
2	12.53	367±12	325±10	313±10	129±5	130±4	137±5
3	9.73	376±4	336±3	322±2	130±3	131±3	136±7
4	9.58	376±4	330±4	317±4	125±2	125±3	127±5
5	7.40	353±6	312±6	300±5	127±3	128±3	128±4

6.1.2.4 Flue Gas Concentrations

Main Flue Gas Constituents. Table 6-6 presents the O₂, CO₂, SO₂, CO, and NO_x concentrations in the flue gas. The results are fairly consistent and are generally what would be expected from past experiences firing similar fuels. Based on the O₂ concentration, there was about a 25% air leak across the system. As seen in Table 6-7, the greatest percentage of the air leak was across the dry ESP. The NO_x removal and the SO₂ removal across the system are shown in Table 6-8. The results, based on a constant O₂ concentration (3%), show that a small amount of NO_x was removed (~13%) and about 88% of the SO₂ was removed.

Particulate Concentrations. The particulate mass loading across each of the three APCDs is shown in Table 6-9. The particulate removal efficiency of the dry ESP was relatively low, ranging from about 75% to 94%. This low removal efficiency is consistent with the low ESP SCA of ~80–90. Typically, a new, well-designed dry ESP will have an SCA of 300–500. However, the inlet dust loading generated firing the SFS was only about one-fourth of that generated by a typical

Table 6-6. Gas Concentrations for Test Series I

Test Period	Total Time, hr	O ₂	CO ₂	CO	NO _x	SO ₂
		Dry ESP In, %	Dry ESP In, %	Dry ESP In, ppm	Dry ESP In, ppm	Dry ESP In, ppm
1	25.5	6.23 ± 1.50	11.8 ± 1.5	14.61 ± 11.56	759 ± 89	2885 ± 299
2	12.5	6.54 ± 0.47	12.3 ± 0.7	5.71 ± 6.25	724 ± 33	2942 ± 104
3	9.7	6.40 ± 0.47	12.3 ± 0.9	4.57 ± 6.13	751 ± 39	2944 ± 154
4	9.6	6.32 ± 0.46	12.6 ± 0.5	22.09 ± 12.60	811 ± 69	2976 ± 154
5	7.4	6.33 ± 0.38	12.0 ± 0.3	30.33 ± 17.02	676 ± 78	2820 ± 70
Test Period	Total Time, hr	O ₂	CO ₂	CO	NO _x	SO ₂
		Wet ESP Out, %	Wet ESP Out, %	Wet ESP Out, ppm	Wet ESP Out, ppm	Wet ESP Out, ppm
1	25.5	8.84 ± 0.94	10.3 ± 1.2	4.24 ± 2.14	538 ± 39	203 ± 81
2	12.5	9.16 ± 0.42	11.3 ± 0.6	3.56 ± 1.54	521 ± 76	377 ± 77
3	9.7	9.22 ± 0.48	9.0 ± 2.0	4.73 ± 5.64	481 ± 139	390 ± 85
4	9.6	9.64 ± 0.25	10.2 ± 0.3	4.65 ± 1.00	653 ± 91	244 ± 91
5	7.4	9.79 ± 0.26	9.8 ± 0.3	4.30 ± 5.58	493 ± 92	218 ± 28

Table 6-7. Air Leakage Across Each APCDs

Test Period	Dry ESP, %O ₂		NH ₃ -Based FGD, ¹ %O ₂		Wet ESP, %O ₂	
1	6.23	7.75	7.75	8.37	8.37	8.84
2	6.54	7.79	7.79	8.52	8.52	9.16
3	6.40	7.63	7.63	8.27	8.27	9.22
4	6.32	7.89	7.89	8.76	8.76	9.64
5	6.33	8.85	8.85	9.00	9.00	9.79
Average	6.36	7.98	7.98	8.58	8.58	9.33
Air Leak, %	12.4		4.8		6.4	

¹ MET NH₃-based FGD.

Table 6-8. Removal Efficiency for NO_x and SO₂ Across the System, based on 3% O₂ concentration

Test Period	Total Time, hr	NO _x			SO ₂		
		Dry ESP In, ppmv	Wet ESP Out, ppmv	Removal, %	Dry ESP In, ppmv	Wet ESP Out, ppmv	Removal, %
1	25.5	925	796	13.9	3516	300	91.4
2	12.5	901	792	12.1	3662	573	84.3
3	9.7	926	735	20.6	3630	596	83.6
4	9.6	994	1034	-4.0	3649	387	89.4
5	7.4	829	792	4.6	3460	350	89.9

Table 6-9. Particulate Removal Efficiencies for Each of the APCDs

Test Period	Dry ESP			FGD ¹			Wet ESP		
	Inlet, gr/scf	Outlet, gr/scf	Removal, %	Inlet, g/scf	Outlet, gr/scf	Removal, %	Inlet, g/scf	Outlet, gr/scf	Removal, %
1	0.5316	0.0311	94.15	0.0311	0.1664	-435.05	0.1664	0.0281	83.11
2	0.7327	0.1812	75.27	0.1812	0.1583	12.64	0.1583	0.0626	60.45
					0.1741		0.1741	0.0638	63.35
3	0.6181	0.0824	86.67	0.0824	0.1848	-124.27	0.1848	0.0819	55.68
	0.6181	0.1496	75.80	0.1496	0.1822	-21.79	0.1822	0.0819	55.05
		0.1160		0.1160	0.1565	-34.91	0.1565	0.0819	47.67
4	0.5469	—	—	—	0.1666	—	0.1666	0.0324	80.55
	0.5798				0.1933		0.1933	0.0243	87.43
					0.1970		0.1970	0.0405	79.44
5	0.5080	0.0280	94.49	0.0280	0.1105	-294.64	0.1105	0.0306	72.31
		0.0280		0.0280	0.1289	-360.36	0.1289	0.0358	72.23

¹ MET NH₃-based FGD system.

pc-fired coal combustor burning a coal with 15% ash. Therefore, the actual particulate loading in the flue gas at the inlet to the NH_3 -based FGD system was not that much different than would be typically seen at a full-scale power plant.

It is clear from the particulate data in Table 6-9 that the NH_3 -based FGD system was generating additional particulate matter. Three mechanisms are possible for aerosols to be formed at the outlet of the scrubber. The first is simply carryover of water droplets from the mist eliminators. The second mechanism is the condensation of the vapor-phase SO_3 resulting in an acid aerosol mist. The third possibility is the reaction of the SO_3 with ammonia, forming ammonium sulfate particles. Although water carryover may be occurring, the method of measuring particulate matter, modified EPA Method 5, does not allow for the measurement of water droplets. To prevent acid condensation on the filter, the temperature of the filter was maintained at a nominal temperature of 400°F (204°C). At this temperature, any water droplets would be vaporized. However, the sampling method would collect any acid aerosols that had already been formed, all ammonium sulfate particles, and any fly ash particles that may have exited the scrubber. A more detailed discussion concerning the composition of the particulate generated at the outlet of the scrubber is presented in Section 6.2.

The primary objective of the project was to determine the efficiency of the wet ESP to remove SO_3 aerosols and reaction products. The goal was to achieve 90% removal across the wet ESP. **It is clear from the data in Table 6-9 that the wet ESP in the configuration used for Test Series I did not achieve this level of control.** With only a few exceptions, the collection efficiency was less than 80%. This level of control would not allow a full-scale system to achieve 10% opacity at the stack. Therefore, it was decided that modifications to the wet ESP would be necessary, followed by additional testing (Test Series II) to prove 90% control could be achieved.

SO_3 , Ammonia, and Chlorides Concentrations. The concentrations of SO_3 /sulfate, NH_3 , and chlorides across each APCD is shown in Table 6-10. The total SO_3 measured was defined as the vapor-phase SO_3 and the SO_3 that is associated with the particulate matter. Although it is assumed for purposes of this report that all of the sulfate measured was due to the SO_3 in the flue gas, a small fraction (the exact quantity is unknown) is also associated with the fly ash alkali components.

The results show a fairly wide fluctuation in the data across the dry ESP. Although the data were not very consistent from day to day, there was general agreement between the inlet and outlet results across the dry ESP. Only a small amount of the SO_3 /sulfate was captured by the dry ESP (~10%).

As would be expected, the vapor-phase SO_3 is at or near zero at the outlet of the NH_3 -based FGD system, and all of the SO_3 /sulfate is measured as particulate matter. Also, across the NH_3 -based FGD system, there appeared to be a small decrease in measured SO_3 /sulfate. However, as discussed previously the actual measured particulate matter increased across the scrubber. This would argue that the increase in particulate matter comes from sulfur reaction products, most likely ammonium sulfate, rather than SO_3 aerosols. It is also interesting to note that when the NH_3 slip increased during Test Period 4, as a result of the pH meter failing to function properly, the amount of SO_3 /sulfate measured at the outlet of the NH_3 -based FGD system increased. Again, the most likely reason is an increase in the ammonium sulfate concentration.

Table 6-10. SO₃, Ammonia Slip, and Chloride Concentrations in the Flue Gas for Test Series I

Sample Point	Test Period	SO ₃ Vapor Phase, ppmv	SO ₃ Particulate, ppmv ¹	SO ₃ Total, ppmv	NH ₃ Slip, ppmv	Chlorides, ppmv
1	1	50.5	6.5	57.0		—
	2	20.3	85.9	106.2		16.9
	3	79.3	35.8	115.1		—
	4	—	—	—		21.8
	5	—	—	—		16.9
2	1	46.7	5.5	52.2		
	2	18.4	81.2	99.6		19.2
	3	56.0	31.9	87.9		25.1
	4	—	—	—		—
	5	—	—	—		21.8
3	1	0.3	43.1±16.1	43.4	—	—
	2	0.3	49.9±19.3	52.2	0.3	1.4
	3	0.3	68.7±5.8	69.0	4.6	0.0
	4	0.3	69.9±9.2	70.2	21.3	2.0
	5	0.3	42.1±5.5	42.4	0.7	2.5
4	1	0.2	10.7	10.9	—	—
	2	0.2	25.6±4.4	25.8	0.3	0.6
	3	0.2	22.5±15.3	22.7	1.2	1.0
	4	0.2	12.1±5.4	12.3	10.0	0.0
	5	0.2	19.2±12.5	19.4	0.5	0.0

¹ Measured as SO₄ in the solids collected on the filters and then converted to the equivalent SO₃.

Across the wet ESP, the removal of SO₃/sulfate was consistent with the removal of particulate matter: 50% to 80%. The concentration of SO₃/sulfate did decrease at the outlet of the wet ESP during the last two test periods when the heaters were turned off, indicating that the wet ESP operated more efficiently, as shown by the generally higher overall particulate collection efficiency.

The chlorides in the flue gas behaved as expected. The average was about 20 ppmv at the inlet to the NH₃-based FGD system and about 1–2 ppmv at the outlet. The dry ESP had little, if any, effect on the chloride concentration in the flue gas. More discussion on the behavior of chlorides during these tests is provided in Section 6.2.

Mercury. Determining mercury behavior during these tests was not a primary focus of this project. However, some mercury measurements were made. The results are shown in Table 6-11. Based on the fuel mercury concentrations shown in Table 6-1, mercury concentration in the Robinson Run coals averaged 0.0807 µg/g for the two samples and 0.0038 µg/g for the petroleum coke. Based on these values, the average fuel feed rate, and gas flow rate, it is expected that the mercury concentration in the flue gas at the inlet to the dry ESP would be 7.10 µg/Nm³. Very little of the mercury generated from firing this coal was captured by the ash as the mercury concentration

Table 6-11. Flue Gas Mercury Data for Test Series I

Sample Point	Hg Particle-Bound, $\mu\text{g}/\text{m}^3$	Hg Oxidized, $\mu\text{g}/\text{m}^3$	Hg Elemental, $\mu\text{g}/\text{m}^3$	Hg Total, $\mu\text{g}/\text{m}^3$
2	0.05	6.26	0.46	6.77
3	0.00	0.84	0.72	1.56
	0.00	0.35	0.51	0.86
4	0.00	0.16	0.56	0.72

in the ESP hopper ash averaged $0.0136 \mu\text{g}/\text{g}$ for six samples. Converting this value to equivalent mercury in the flue gas results in $0.22 \mu\text{g}/\text{Nm}^3$. Therefore, based on these values, the mercury concentration at the outlet of the dry ESP would be expected to be $6.88 \mu\text{g}/\text{Nm}^3$ compared to the measured value of $6.77 \mu\text{g}/\text{Nm}^3$. This is an excellent mercury balance. The mercury speciation is also fairly typical for a high-sulfur eastern bituminous coal as $>90\%$ is in the oxidized form. Therefore, as expected, the NH_3 -based FGD system removed $>80\%$ of the mercury with the remainder of the oxidized mercury being removed by the wet ESP. The scrubber did not remove any of the elemental mercury.

6.1.3 Mass Balances Across the Wet ESP

The mass loading at the inlet and outlet of the wet ESP for each of the important components in the flue gas is shown in Table 6-12. An attempt was made to determine the composition of the particulate matter exiting the NH_3 -based FGD systems and the wet ESP. Possible sulfated components of the particulate matter are ammonium sulfate, ammonium bisulfate, SO_3 aerosols, and sulfated fly ash particles (CaSO_4 and Na_2SO_4 , etc.). The reaction of SO_3 with free ammonia to form ammonium sulfate and ammonium bisulfate is shown by the following two reactions:

If assuming all the NH_3 measured in the particulate matter reacted with SO_3 to form $(\text{NH}_4)_2\text{SO}_4$, the mass ratio of NH_3 to SO_3 would be 0.425. If, however, $(\text{NH}_4)\text{HSO}_4$ is formed, the ratio would be 0.212. An $(\text{NH}_3)\text{HSO}_4$ reaction product would form if the system was ammonia starved.

As seen from Table 6-12, this ratio was generally between 0.425 and 0.212 at both the inlet and outlet of the wet ESP, indicating that both reactions were occurring. In addition, it is quite possible that there was a carryover of very fine sulfated particles. It should be noted that the chloride composition in the particulate at these two locations was very low and, therefore, would not have much impact on the availability of ammonia to react with SO_3 .

Table 6-12. Sulfate–NH₃ Mass Balances at the Inlet and Outlet of the Wet ESP for Test Series I

Date	Total SO ₄ , gr/scf	NH ₃ , gr/scf	Chlorides, gr/scf	Total Mass Loading, gr/scf	Measured NH ₃ /SO ₃ mass ratio	Mass NH ₄ –SO ₄ Products to Total Mass, %
<i>Sampled at Inlet to Wet ESP</i>						
4-23	0.0965	0.0318	3.096E-05	0.1664	0.396	78.2
4-24	0.0908	0.0208	1.196E-04	0.1583	0.259	71.3
4-24	0.1183	0.0228	3.162E-05	0.1741	0.231	81.8
4-25	0.1369	0.0298		0.1848	0.261	91.2
4-25	0.1140	0.0226		0.1565	0.238	88.1
4-25	0.1192	0.0371		0.1565	0.374	101.3
4-26	0.1355	0.0525		0.1666	0.465	114.7
4-27	0.0806	0.0220		0.1105	0.327	94.0
<i>Sampled at Outlet of Wet ESP</i>						
4-23	0.0191	0.0053		0.0281	0.333	87.9
4-24	0.0512	0.0106		0.0626	0.248	99.7
4-24	0.0365	0.0082		0.0638	0.270	70.8
4-25	0.0528	0.0191		0.0819	0.434	89.2
4-25	0.0584	0.0144		0.0819	0.296	89.9
4-26	0.0287	0.0108		0.0324	0.451	123.9

Comparing the total measured mass at each location to measured mass of NH₄ plus SO₄ (last column in Table 6-12), it appears that particulate matter is composed of other components in addition to the NH₃–SO₄ products (as indicated by <100%). As stated earlier, this may be due to fine fly ash particles that pass through the APCD.

6.1.4 Particle-Size Distribution

The size distribution of particles in the flue gas was measured using multicyclones and the APS/SMPS instruments. The multicyclone was used to measure the PSD at the inlet of the dry ESP. The results are shown in Figures 6-1 and 6-2. The overall particulate loading is somewhat low for the amount of ash in the fuel (0.6 gr/scf [1.43 g/m³] compared to the expected 3 gr/scf [6.88 g/m³]). Based on the multicyclone data, the PSD is smaller than typical pc-fired systems; More than likely, this was because the SFS has a relatively high surface-to-volume ratios.

The mass mean diameter (D₅₀) at the inlet to the dry ESP averaged 8.2 μm, which is typical for a pc-fired coal combustor (5–15 μm). There does appear to be somewhat of a deviation from a log normal distribution (which would be represented by a straight line) for the very fine particles, indicating slightly more fine particles than what would be expected. As stated earlier, this may be a result of the high SFS surface-to-volume ratio. However, this deviation is not excessive. Based on data obtained using a Malvern light-scattering analyzer, the D₅₀ for the dry ESP hopper ash averaged 3.37 ± 0.27 μm based on Malvern analysis, with very little difference in size between the two fields. This is substantially smaller particle size than would be expected.

Figure 6-1. Fly ash PSD collected at the inlet of the dry ESP using a multicyclone for Test Series I – Sample 1.

Figure 6-2. Fly ash PSD collected at the inlet of the dry ESP using a multicyclone for Test Series I – Sample 2.

The APS/SMPS near-real-time instruments were used to determine the PSD across the wet ESP. These results are shown in Figures 6-3 and 6-4. These graphs were made by combining the results of the APS with those of the SMPS. Because of how these two instruments work, the crossover point 0.7 and 1.0 μm is not very well defined. However, these graphs show that the particulate matter at both the inlet and outlet of the wet ESP has a very small PSD based on both a mass and particle count, as seen in Figures 6-3 and 6-4. Almost all the particles have a geometric diameter of $<0.3 \mu\text{m}$. The data are consistent for a case when the particulate matter was formed as result of chemical reactions. This provides additional evidence that a high percentage of the measured particulate matter was either $(\text{NH}_4)_2\text{SO}_4$ or $(\text{NH}_4)\text{HSO}_4$.

6.2 Characterization of Emissions from the Dry ESP, MET Scrubber, and Wet ESP – Pilot-Scale Test Series II

The test plan for Test Series II was somewhat different than for Test Series I. A more parametric evaluation was done based on fuel (higher levels of petroleum coke) and the use of humidification. In addition, because of the relatively poor performance of the wet ESP in Test Series I, the electrodes were redesigned, and the two fields of the wet ESP were reconfigured. The results of these pilot-scale tests are discussed in Section 6.2.

6.2.1 Fuel Analysis

The fuels used for Test Series II were the same as those used for Test Series I. The coal was a Robinson Run eastern bituminous coal, and the petroleum coke was obtained from a refinery in Louisiana. The analysis of the coal and petroleum coke is shown in Table 6-13. As seen by the fuel analyses (comparing Table 6-1 to Table 6-13), the fuel characteristics had not substantially changed during the 4-months' storage between tests.

6.2.2 Process Conditions

6.2.2.1 Fuel Feed Rates

As was the case for the first test series, the coal and petroleum coke were pulverized prior to being fired in the SFS. The results showed that the coal averaged 60% $<200 (< 74 \mu\text{m})$ mesh and the petroleum coke was 66.2% $<200 (< 74 \mu\text{m})$ mesh. The relatively low carbon content in the fly ash collected in the dry ESP indicated that good combustion occurred. The LOI and carbon content for the dry ESP hopper ash are shown in Table 6-14. With humidification, the LOI of the ash increased, but the carbon content generally remained $<0.40 \text{ wt}\%$. This must be due to the formation of some type of hydrate compound.

Based on plugging experiences in the CAH during Test Series I, the EERC elected to fire natural gas in the SFS unit at night and clean the CAH on-line. As part of the parametric evaluation conducted during Test Series II, the amount of petroleum coke in the fuel blend was varied from test to test. The coal-coke feed rates and the flue gas flow rates for each day of testing are shown in Table 6-15. The nominal percentage of petroleum coke for Tests 2, 4, and 6 was 20% and for Tests 3 and 5, 30%. To measure flow rates, a venturi was located at the exit of the wet ESP, and a pitot tube

Figure 6-3. Fly ash PSD, on a number concentration and mass basis, at the inlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series I.

Figure 6-4. Fly ash PSD, on a number concentration and mass basis, at the outlet of the wet ESP as measured in near real time using the APS/SMPS instruments (Test Series I).

Table 6-13. Analysis of Fuels Used for Test Series II, on a dry basis

	Robinson Run Bituminous Coal	Petroleum Coke
<i>Proximate Analysis, wt%</i>	<i>2 analyses</i>	<i>1 analysis</i>
Moisture Content	1.0	0.76
Volatile Matter	40.07	12.38
Fixed Carbon	44.71	86.43
Ash	15.23	1.19
<i>Ultimate Analysis, wt%</i>	<i>2 analyses</i>	<i>1 analysis</i>
Hydrogen	4.84	3.41
Carbon	70.16	85.41
Nitrogen	1.35	2.12
Sulfur	4.80	7.84
Oxygen, by difference	3.64	0.03
Heating Value, Btu/lb	12,290	14,334
<i>Ash Fusion Temperatures, °F</i>	<i>2 analyses</i>	<i>1 analysis</i>
Initial Temperature	2407	2324*
Softening Temperature	2437	2484*
Hemi. Temperature	2555	2343*
Fluid Temperature	2610	2466*
<i>Coal Analysis</i>	<i>2 analyses</i>	<i>1 analysis</i>
Mercury, µg/g	0.0807*	0.0038*
Chlorides, µg/g	504	<50
<i>Coal Ash Analysis, % conc. as oxides**</i>	<i>2 analyses</i>	<i>1 analysis</i>
SiO ₂	46.8	33.3
Al ₂ O ₃	22.5	9.59
Fe ₂ O ₃	15.9	16.0
TiO ₂	0.92	0.56
P ₂ O ₅	0.19	0.14
CaO	3.36	3.65
MgO	1.92	1.40
Na ₂ O	1.14	1.29
K ₂ O	2.27	1.22
BaO	0.084	<0.042
MnO	0.039	<0.01
SrO	0.092	<0.01
NiO	—	2.34
V ₂ O ₅	—	27.2
SO ₃	4.85	3.27
<i>Coal Ash Analysis, mg/kg</i>	<i>2 analyses</i>	<i>1 analysis</i>
Cr	125	<100
Cu	<100	<100
Ni	<100	—
V	230	—
Zn	100	160

* These values are from Test Series I. New analyses were not done.

** Ni and V for the petroleum coke are reported as oxides because of the high concentrations.

Table 6-14. Carbon Content of the Dry ESP Hopper Ash Samples Collected During Test Series II

Day	Fuel Blend			Field 1	Field 1	Field 2	Field 2
	Coal, wt%	Petroleum Coke, wt%	Humid. Used	LOI, wt%	Ash Carbon, wt%	LOI, wt%	Ash Carbon, wt%
1	100	0	No	6.23	0.10	3.38	0.26
2	80	20	No	2.12	0.14	2.34	0.30
3	70	30	No	6.48	0.26	4.34	0.18
4	80	20	Yes	15.59	0.38	15.06	0.18
5	70	30	Yes	17.59	0.41	12.45	0.73
6 ¹	80	20	No	5.68	0.36	12.05	0.28

¹ Gas velocity through wet ESP was increased from 9 to 10 ft/sec.

Table 6-15. Fuel Feed Rates for Test Series II

Test No.	Time, hr	Coal Feed Rate, lb/hr	Pet. Coke Feed Rate, lb/hr	Petroleum Coke in Fuel, wt%	Flue Gas Flow Rate (venturi), scfm	Flue Gas Flow Rate, (pitot), scfm
1	17.02	125	0	0	487.33±39.28	441.50±7.41
2	9.10	100	24	19.4	438.92±11.35	433.75±6.40
3	12.25	85	36	29.8	437.42±5.48	436.30±11.94
4	12.58	100	24	19.4	435.49±18.39	452.64±11.05
5	12.97	88	36	29.0	445.96±12.42	451.00±6.62
6	12.08	103	24	18.9	480.97±12.39	477.75±4.46

was located at the exit of the NH₃-based FGD. The results shown in Table 6-15 are calculated on the same basis so a comparison can be made.

6.2.2.2 Operational Data for the Two ESPs

It was believed that the relatively poor results obtained from the wet ESP during the first test series was a result of current limitations. Therefore, major modifications to the wet ESP were made prior to the Series II testing. As discussed in Section 3.4, the first field was reduced in size from 8 to 4 linear ft (2.44 to 1.22 m), and the second field was increased from 8 ft to 12 linear ft (2.44 to 3.66 m). More importantly, the electrodes were completely redesigned to increase current density and improve the overall electrical fields. The results of these modifications can be seen in Table 6-16, which presents the voltage and current data for both the wet and dry ESPs. Comparing the wet ESP data in Test Series I (Table 6-3) with Tests Series II (Table 6-16), substantially more current was able to be generated without sparking using the new wet ESP configuration and power supplies. As will be discussed later in this report, the wet ESP operated much more effectively using the new electrodes and power supplies.

Table 6-16. Operational Data for the Two ESPs for Test Series II¹

Test No.	Wet ESP		Wet ESP		Dry ESP		Dry ESP	
	Wet ESP Voltage Field 1, kV	Current Field 1, mA	Wet ESP Voltage Field 2, kV	Current Field 2, mA	Dry ESP Voltage Field 1, kV	Current Field 1, mA	Dry ESP Voltage Field 2, kV	Current Field 2, mA
1	45.12	0.34	40.08	3.31	36.92	1.68	40.58	7.01
	7.48	0.15	3.17	3.99	3.48	1.96	3.28	3.10
2	52.78	0.86	43.44	12.25	40.13	0.36	46.75	3.00
	2.84	0.29	3.48	5.85	0.60	0.11	0.83	2.05
3	50.88	1.38	44.46	7.52	44.41	0.55	43.96	6.08
	0.68	0.87	4.86	7.21	2.39	0.32	5.68	3.71
4	44.50	2.75	42.00	9.52	38.17	1.81	45.58	15.55
	4.46	2.24	5.02	7.63	1.34	0.83	4.44	15.67
5	50.00	3.95	39.33	5.07	35.67	1.98	39.78	11.18
	0.00	1.34	0.82	5.06	1.70	0.60	0.79	4.58
6	50.00	0.66	43.29	3.50	41.92	1.35	47.63	7.30
	0.00	0.22	2.62	1.41	5.16	0.21	3.08	4.19

¹ The first number is the average for the test period; the number directly below is the standard deviation.

6.2.2.3 Flue Gas Temperatures

The resultant flue gas temperatures at the inlet and outlet of each of the APCDs are shown in Table 6-17. For the two tests where humidification was used (Tests 4 and 5), there was approximately a 90°F (32°C) temperature decrease at the inlet of the dry ESP. This is somewhat higher than would be typically used at full-scale power plants. For example, humidification tests conducted at the R. Paul Smith Station resulted in a temperature drop of about 30°F (32°C) (4). However, the ESP inlet temperature for the pilot-scale tests was 370°F (188°C) compared to only 305°F (152°C) at the R. Paul Smith Station. The final temperature in both cases was about the same, 270°–275°F (132°–135°C).

Table 6-17. Flue Gas Temperatures for Tests Series II

Test Period	Total Time, hr	Temp. Dry ESP In, °F	Temp. Dry ESP Out, °F	Temp. FGD In, °F	Temp. FGD Out, °F	Temp. Wet ESP In, °F	Temp. Wet ESP Out, °F
1	17.02	370±9	335±8	325±8	127±2	128±2	128±3
2	9.10	368±5	335±5	325±5	131±11	132±6	134±7
3	12.25	368±5	335±4	326±4	130±4	131±4	133±4
4	12.58	275±8	259±6	254±7	131±2	131±2	135±4
5	12.97	275±5	260±7	254±8	132±4	133±4	134±5
6	12.08	363±2	334±2	326±2	132±2	132±2	132±4

6.2.2.4 Flue Gas Concentrations

Main Flue Gas Constituents. Table 6-18 presents the O₂, CO₂, SO₂, CO, and NO_x concentrations in the flue gas. The results are fairly consistent, and with the exception of the SO₂ concentration, they were about what were expected. Based on the sulfur concentration in the fuel, the SO₂ concentration was somewhat lower than expected. Also, there was not as much change in SO₂ concentration as expected when the amount of petroleum coke in the fuel blend was varied. The reasons for this observation are unknown; the instruments were calibrated on a regular basis and appeared to be working well.

Although there was an attempt to better seal the dry ESP for Test Series II, based on the O₂ concentration, there was about a 23% air leak across the system compared to 25% in Test Series I. Although the O₂ analyzers were only operating properly at the inlet to dry ESP and outlet of wet ESP (providing the air leakage across all three APCDs), it was expected that the highest percentage of air leakage was still across the dry ESP. The NO_x removal and the SO₂ removal across the system are shown in Table 6-19. The results, based on a constant O₂ concentration (3%), show that a small amount of NO_x was removed (~13%) and an average of about 88% of the SO₂. This was very similar to the results obtained in Test Series I.

Particulate Concentrations. The particulate mass loading across each of the three APCDs is shown in Table 6-20. The particulate removal efficiency of the dry ESP was relatively low, ranging from about 57% to 96%. However, the overall efficiency may have been marginally better than was the case for Test Series I, particularly for the tests using humidification. Also, beginning with Test 3, the performance of the dry ESP was improved by switching power supplies, allowing more current to be used in Field 2 of the dry ESP.

Table 6-18. Gas Concentrations for Test Series II

Test No.	CO ₂ Dry ESP In, %	CO Dry ESP In, ppm	O ₂ Dry ESP In, %	NO _x Dry ESP In, ppm	SO ₂ Dry ESP In, ppm
1	11.9 ±0.65	106.48±3.95	7.11 ±0.75	582±138	2603±107
2	12.2 ±0.34	49.13±5.67	5.88 ±0.96	853±38	2863±141
3	12.5 ±0.26	0.86±0.01	6.23 ±0.22	862±41	2994±55
4	12.3 ±0.25	0.82±0.01	6.33 ±0.29	877±27	2969±57
5	12.5 ±0.52	0.80±0.01	6.48 ±0.71	587±30	2969±105
6	12.7 ±0.31	0.79±0.01	6.55 ±0.28	532±48	2980±132

Test No.	CO ₂ Wet ESP Out, %	CO Wet ESP Out, ppm	O ₂ Wet ESP Out, %	NO _x Wet ESP Out, ppm	SO ₂ Wet ESP Out, ppm
1	9.9±1.32	4.84 ±0.84	9.24 ±0.60	852 ±13	184±109
2	10.2±0.62	4.17 ±0.70	9.29 ±0.35	601±25	262±78
3	10.1±1.10	3.04 ±0.62	8.83 ±0.50	737 ±88	403±118
4	10.2±0.35	3.98 ±0.91	9.34 ±0.32	637 ±34	380±83
5	10.6±0.94	4.07 ±0.84	9.18 ±0.52	346 ±25	343±95
6	10.5±0.46	5.26 ±0.82	9.15 ±0.29	335±31	319±74

Table 6-19. Removal Efficiency for NO_x and SO₂ Across the System, based on 3% O₂ concentration

Test Period	Total Time, hr	NO _x			SO ₂		
		Dry ESP In, ppmv	Wet ESP Out, ppmv	Removal, %	Dry ESP In, ppmv	Wet ESP Out, ppmv	Removal, %
1	17.02	1104	890	19.4	3984	281	92.9
2	9.10	1016	924	9.1	4401	403	90.8
3	12.25	1050	1089	-3.8	4428	597	86.5
4	12.58	1076	982	8.6	4584	586	87.2
5	12.97	727	527	27.5	4521	522	88.4
6	12.08	662	509	23.1	4526	485	89.3

Table 6-20. Particulate Removal Efficiencies for Each of the APCDs in Test Series II

Test Period	Dry ESP			Wet FGD			Wet ESP		
	Inlet, gr/scf	Outlet, gr/scf	Removal, %	Inlet, g/scf	Outlet, gr/scf	Removal, %	Inlet, g/scf	Outlet, gr/scf	Removal, %
1	0.1870	0.0248	86.74	0.0248	0.1299	-423.79	0.1299	0.0110	91.53
1				0.0248	0.1269	-411.69	0.1269	0.0268	78.88 ¹
2	0.4340	0.1312	69.77	0.1312	0.1402	-6.86	0.1402	0.0042	97.00
2				0.1312	0.1510	-15.09	0.1510	0.0199	86.82 ¹
2				0.1312	0.1275	2.82	0.1275	0.0032	97.49
3	0.0905	0.0173	80.88	0.0173	0.1737	-904.05	0.1737	0.0062	96.43
3	0.0905	0.0388	57.13	0.0388	0.1662	-328.35	0.1662	0.0033	98.01
							0.1700	0.0062	96.35
4	0.1713	0.0055	96.79	0.0055	0.0201	-265.45	0.0201	0.0003	98.51
4	0.1713	0.0064	96.26	0.0064	0.0232	-262.50	0.0232	0.0001	99.57
4				0.0060	0.0269	-348.33	0.0269	0.0009	96.65
5	0.3102	0.0200	93.55	0.0200	0.0265	-32.50	0.0265	0.0001	99.62
5	0.3102	0.0542	82.53	0.0542	0.0273	49.63	0.0273	0.0001	99.63
5							0.0269	0.0011	95.91
6	0.2349	0.0164	93.02	0.0164	0.1730	-954.88	0.1730	0.0063	96.36
6	0.2349	0.0086	96.34	0.0086	0.1766	-1953.49	0.1766	0.0085	95.19
6				0.0125	0.1739	-1291.20	0.1739	0.0190	89.07 ¹

¹ The power to the wet ESP tripped out during test.

As was the case in Test Series I, the NH₃-based FGD system was generating additional particulate matter. Although the inlet particulate loading to the NH₃-based FGD system was somewhat erratic, the outlet dust loading measurements were very similar. The tests using humidification resulted in significantly lower dust loadings. This may be because of reduced SO₃ at the lower temperatures.

As stated earlier, the primary objective of the project was to determine the efficiency of the wet ESP to remove SO₃ aerosols and reaction products. The goal was to achieve 90% removal across the wet ESP. The new electrode configuration and change in power supplies used in Test Series II greatly improved the performance of the wet ESP over that observed in Test Series I. **With the exception of a few tests where the power on Field 1 tripped out, >90% control was easily achieved.** This was even true for Test 6, where the flue gas flow rate was increased such that the velocity through the wet ESP increased from 9 to 10 ft/sec (2.74 to 3.05 m/s). Overall, it appeared the use of humidification resulted in somewhat less particulate emissions at the outlet of the wet ESP compared to the other tests. There did not appear be to any major differences among the tests based on the percentage of petroleum coke in the fuel. It was possible that firing petroleum coke improved the overall performance of the system, as the baseline (100% coal) tests had the poorest wet ESP performance. However, this may simply be a result of being the first test of the week. Also, only two samples were taken, and one was not valid because of the power supply shutting down. The effectiveness of the wet ESP is shown in Figures 6-5 and 6-6, which show the EERC stack with and without the wet ESP. Although the stack is small and there is substantial air dilution, there is a clear difference (visible plume versus clear stack) in plume opacity with the wet ESP operating.

SO₃, Ammonia, and Chloride Concentrations. The concentrations of SO₃/sulfate, ammonia, and chloride across each of the three APCDs are shown in Table 6-21. The total SO₃ measured was defined as the vapor-phase SO₃ and the SO₃ that is associated with the particulate matter. As before, it was assumed, for purposes of this report, that all of the sulfate measured was due to the SO₃ in the flue gas.

The results show that, without humidification, the dry ESP has only a small, if any, effect (several tests showed a slight increase) on the SO₃/sulfate. However, with humidification, 85% and 77% of the SO₃/sulfate was removed in the dry ESP, for Tests 4 and 5, respectively. This resulted in much lower SO₃/sulfate concentrations at the outlet of the wet ESP. The increase in SO₃ removal in the dry ESP is a likely explanation for the increase in dry ESP hopper ash LOI observed for the tests with humidification. Based on XRF analysis of the fly ash, the SO₃ concentration in the ash increased, as would be expected.

Across the NH₃-based FGD system, there was almost a 50% decrease in the SO₃/sulfate concentration. Based on Test Series I data, the vapor-phase SO₃ concentration is essentially zero. The exception was the baseline test where the measured SO₃/sulfate removal was only 18% across the NH₃-based FGD system. For all tests, the total measured particulate loading increased across the NH₃-based FGD system. The increase is a result of the vapor-phase SO₃ reacting with NH₃, forming NH₃-SO₄ products, and although some is removed by the NH₃-based FGD, enough passes through to increase the outlet dust loading. A visual inspection of the filter showed that the collected particulate matter was a white powder.

Across the wet ESP, the removal of SO₃/sulfate was consistent with the removal of particulate matter, >90%. Proving the excellent performance of the wet ESP during the pilot-scale testing.

With the exception of Test 5, at the outlet of the NH₃-based FGD system, the ammonia slip was low. For Test 5, the ammonia slip measured 13 ppmv; this was a result of problems that occurred with the controlling pH meter during this test.

Figure 6-5. Photograph of the EERC SFS stack with the wet ESP off-line.

Figure 6-6. Photograph of the EERC SFS stack with the wet ESP on-line.

Table 6-21. SO₃, Ammonia Slip, and Chloride Concentrations in the Flue Gas for Test Series II

Sample Point	Test No.	SO ₃ Vapor Phase, ppmv	SO ₃ ^a Particulate, ppmv	SO ₃ Total, ppmv	NH ₃ Slip, ppmv	Chlorides, ppmv
1	1	84.20	10.69	94.89	— ^b	—
	2	85.16±11.50	8.86	94.01	—	—
	3	98.16±10.40	6.91	105.07	—	—
	4	118.21±0.55	5.47	123.68	—	—
	5	116.37±12.37	7.56	123.94	—	—
	6	150.48±3.72	6.99	157.47	—	—
2	1	62.58	1.59	64.18	—	33.36
	2	92.33±21.55	43.97	136.30	—	20.02
	3	103.88±12.39	26.51 ±9.73	130.39	—	27.20
	4	16.25±6.74	1.96 ±0.82	18.21	—	27.81
	5	16.08±0.01	10.25 ±3.56	26.34	—	23.61
	6	125.36±3.45	1.19 ±0.91	126.55	—	26.80
3	1	—	52.18 ±4.38	52.18	1.93	1.55
	2	—	61.62 ±8.06	61.62	0.10	1.24
	3	—	67.41 ±5.16	67.41	0.08	1.06
	4	—	10.02 ±1.17	10.02	2.82	0.59
	5	—	13.01 ±1.96	13.01	12.97	0.73
	6	—	75.32 ±0.59	75.32	0.15	0.84
4	1	—	8.59 ±5.02	8.59	0.86	<0.1
	2	—	3.99 ±4.43	3.99	0.12	<0.1
	3	—	1.53 ±0.55	1.53	0.03	<0.1
	4	—	0.08 ±0.03	0.08	0.83	<0.1
	5	—	0.12 ±0.03	0.12	1.31	<0.1
	6	—	3.33 ±1.05	3.33	0.06	0.21

^a Measured as SO₄ in the solids collected on the filters and then converted to the equivalent SO₃.

^b Not measured.

The chlorides in the flue gas behaved similar to Test Series I. The average was about 25 ppmv at the inlet to the NH₃-based FGD system and about 1–2 ppmv at the outlet with the remainder removed by the wet ESP. The chloride concentrations observed at the inlet of the NH₃-based FGD system are consistent with the fuel chloride concentration measured.

Although the test series was very short—six days—there was a minimal attempt to determine the corrosion potential of the wet ESP. Toward the end of the test, the pH of the solution collected from the wet ESP was measured and determined to be very acidic (pH of ~1). The acidity of the solution must be a result of either HCl or H₂SO₄ formation. Although a chloride balance around the wet ESP was not a primary focus of the project, and would be extremely difficult to do, enough measurements were made to make some estimates. The sources of chlorides into the wet ESP are:

- Vapor-phase chlorides in the flue gas (measured at Point 3)
- Liquid carryover from the NH_3 -based FGD system (measured as a dust loading at Point 3)
- Water used to wash the wet ESP

Chlorides exiting the wet ESP are:

- Vapor-phase chlorides exiting the wet ESP (measured at Point 4)
- Wash water from the wet ESP
- Chloride concentration of the particulate exiting the wet ESP (measured as a dust loading at Point 4).

Based on the chloride concentration measured for each of these components, it appears there is substantially more chloride in the wet ESP wash than can be accounted for in the other components. However, not all of the wash samples were collected, and there was a great deal of variation in the concentrations measured. They varied from a high of 16,100 mg/L to a low of 4800 mg/L for Field I. The wet ESP was taken off-line and washed every 2 hours with about 5 gal (18.9 L) of tap water. A much more rigorous study is necessary to fully assess the chlorine concentrations and complete an accurate chloride mass balance.

It also would not be expected that substantial amounts of H_2SO_4 would condense on the walls of the wet ESP. As mentioned earlier, the vapor-phase SO_3 was very low following the NH_3 -based FGD system. Although the sulfate concentration in the wash water was high (>5000 mg/L), it is expected that this is primarily $(\text{NH}_3)_2\text{SO}_4$ and, therefore, would have little effect on pH.

6.2.3 Mass Balances Across Wet ESP

The mass loading at the inlet and outlet of the wet ESP for the important flue gas components in the flue gas is shown in Table 6-22. As was the case for Test Series I, an attempt was made to determine the composition of the particulate matter exiting the NH_3 -based FGD system and the wet ESP, based on the measured NH_3 and SO_4 concentrations.

Again, assuming all the NH_3 measured in the particulate matter reacted with SO_3 to form $(\text{NH}_4)_2\text{SO}_4$, the mass ratio of NH_3 to SO_3 would be 0.425. If however, $(\text{NH}_4)\text{HSO}_4$ is formed, the ratios would be 0.212.

Although the NH_3/SO_3 ratios are somewhat lower than was the case for Test Series I, (Table 6-12 versus Table 6-22) they were generally between 0.425 and 0.212 at both the inlet and outlet of the wet ESP, indicating that both reactions were more than likely occurring. At the outlet of the wet ESP, the average NH_3/SO_3 ratio for the test is much closer to 0.212 than 0.425. This would appear to indicate a higher percentage of NH_4HSO_4 rather than $(\text{NH}_3)_2\text{SO}_4$. However, the particulate collection efficiency of the wet ESP was very high, resulting in very low mass loadings. It should be noted that the chloride composition in the particulate at these two locations was very low and, therefore, would not have an impact on the availability of ammonia to react with SO_3 .

Table 6-22. Sulfate–NH₃ Mass Balances at the Inlet and Outlet of the Wet ESP for Test Series II

Test No.	Total SO ₄ , gr/scf	NH ₃ , gr/scf	Total Mass Loading, gr/scf	Measured NH ₃ /SO ₃ Mass Ratio	Mass NH ₄ –SO ₄ Products to Total Mass, %
<i>Inlet to the Wet ESP</i>					
1	0.0981	0.0325	0.1299	0.397	102.0
1	0.0871	0.0334	0.1269	0.461	96.5
2	0.1244	0.0166	0.1402	0.160 ¹	101.2
2	0.1078	0.0233	0.1510	0.259	87.7
2	0.0959	0.0208	0.1275	0.260	92.4
3	0.1298	0.0167	0.1737	0.154 ¹	84.9
3	0.1120	0.0237	0.1662	0.254	78.9
3	0.1171	0.0186	0.1700	0.191 ¹	82.3
4	0.0165	0.0043	0.0201	0.311	104.9
4	0.0166	0.0056	0.0232	0.407	97.4
4	0.0202	0.0069	0.0269	0.409	102.1
5	0.0206	0.0069	0.0265	0.404	105.5
5	0.0255	0.0051	0.0273	0.240	113.4
6	0.1348	0.0213	0.1730	0.190 ¹	91.0
6	0.1327	0.0303	0.1766	0.274	93.3
6	0.1335	0.0280	0.1739	0.252	93.8
<i>Outlet of the Wet ESP</i>					
1	0.0089	0.0017	0.0110	0.229	96.8
1	0.0215	0.0068	0.0268	0.381	107.4
2	0.0030	0.0005	0.0042	0.201 ¹	83.0
2	0.0162	0.0032	0.0199	0.239	98.2
2	0.0022	0.0004	0.0032	0.235	81.3
3	0.0037	0.0006	0.0062	0.208 ¹	71.5
3	0.0018	0.0005	0.0033	0.324	70.4
3	0.0026	0.0005	0.0062	0.239	50.1
4	0.0001	0.0001	0.0003	— ¹	—
4	0.0001	0.0001	0.0001	—	—
4	0.0002	0.0001	0.0009	—	—
5	0.0002	0.0001	0.0001	—	—
5	0.0002	0.0001	0.0001	—	—
5	0.0003	0.0001	0.0011	—	—
6	0.0046	0.0008	0.0063	0.254	86.4
6	0.0072	0.0014	0.0085	0.312	101.9
6	0.0896 ²	0.0019	0.0190	0.386	482.2

¹ The mass loadings are too low to arrive at a meaningful value.

² Appears to be a bad number.

Comparing the total measured mass at the wet ESP inlet to measured mass of NH_4 plus SO_4 (last column in Table 6-22) shows that the particulate matter was almost entirely $\text{NH}_4\text{--SO}_4$ reaction products. This indicates that the dry ESP removed fly ash more efficiently compared to the first test series (Table 6-12) where most of the values were <95%.

6.2.4 Particle-Size Distribution

The PSD in the flue gas was measured using multicyclones and the APS/SMPS instruments. The multicyclone was used to measure the PSD at the inlet of the dry ESP. The results are shown in Figures 6-7 and 6-8. As was the case in the first test series, the particulate loading to the dry ESP is low for the amount of ash in the fuel (0.3 gr/scf [0.69 g/m³]) compared to the expected 3 gr/scf [6.9 g/m³]). However, the PSD is fairly typical for coal-fired boilers. The D_{50} averaged 12.0 μm . Again, mass loading and PSD are affected by the SFS surface to volume ratio and heat transfer surfaces. Again, there appears to be a deviation from a log normal distribution (represented by a straight line) for the very fine particles, indicating slightly more fine particles than what would be expected. However, this deviation is not excessive. The D_{50} for the dry ESP hopper ash was measured to be about 6 μm . This is shown in Table 6-23.

The APS/SMPS near-real-time instruments were used to determine the PSD across the wet ESP. These results are shown in Figures 6-9 through 6-16 for Test Periods 2, 4, 5, and 6. These graphs were made by combining the results of the APS with those of the SMPS. Because of how these two instruments work, the crossover point 0.7 to 1.0 μm is not very defined. These graphs show that the particulate matter at both the inlet and outlet of the wet ESP has a very small PSD on

Figure 6-7. Fly ash PSD collected at the inlet of the dry ESP using a multicyclone for Test Series II – Day 1.

Figure 6-8. Fly ash PSD collected at the inlet of the dry ESP using a multicyclone for Test Series II – Day 5.

both a mass and particle number concentration basis. This can be clearly seen in Figures 6-9 through 6-16 when looking at the PSD based on number of particles. Almost all the particles have a geometric diameter of $<0.3 \mu\text{m}$. The data are consistent for a case when the particulate matter was formed as result of chemical reactions. This provides additional evidence that the measured particulate matter was $(\text{NH}_4)_2\text{SO}_4$ and $(\text{NH}_4)\text{HSO}_4$.

Table 6-23. Particle Diameters for Dry ESP Hopper Ash at the 50% Cut Point (D_{50}) for Test Series II¹

Day	Fuel Blend		Humidification Used	Field 1, μm	Field 2, μm
	Coal, wt%	Petroleum Coke, wt%			
1	100	0	No	8.63	6.71
2	80	20	No	7.57	3.39
3	70	30	No	4.17	3.84
4	80	20	Yes	9.22	10.42
5	70	30	Yes	10.24	6.81
6 ¹	80	20	No	5.01	5.28

¹ Gas velocity through the wet ESP was increased from 9 to 10 ft/sec.

Figure 6-9. Fly ash PSD, on a number and mass concentration basis, at the inlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series II – Day 2.

Figure 6-10. Fly ash PSD, on a number and mass concentration basis, at the outlet of the wet ESP as measured in near real time using the APS/SMPS instrument for Test Series II – Day 2.

Figure 6-11. Fly ash PSD, on a number and mass concentration basis, at the inlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series II – Day 4.

Figure 6-12. Fly ash PSD, on a number and mass concentration basis, at the outlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series II – Day 4.

Figure 6-13. Fly ash PSD, on a number and mass concentration basis, at the inlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series II – Day 5.

Figure 6-14. Fly ash PSD, on a number and mass concentration basis, at the outlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series II – Day 5.

Figure 6-15. Fly ash PSD, on a number and mass concentration basis, at the inlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series II – Day 6.

Figure 6-16. Fly ash PSD, on a number and mass concentration basis, at the outlet of the wet ESP as measured in near real time using the APS/SMPS instruments for Test Series II – Day 6.

6.2.5 Mercury in the Ammonium Sulfate Product

Although no mercury flue gas samples were taken, the EERC attempted to estimate the mercury associated with the ammonium sulfate product. At the end of Test Series II, a slurry sample was collected, filtered, and the weight of the solids recorded. The solids collected consist of fly ash that escaped the dry ESP and ammonium sulfate. To separate these two solid materials, the soluble ammonium sulfate was redissolved in deionized water. This approach assumed that the fly ash was not soluble. The solution was then filtered, and the mercury concentration of the liquid fraction was measured. Knowing the amount of solid material that goes into solution and assuming that the soluble fraction was ammonium sulfate, the concentration of mercury in ammonium sulfate was $0.00097 \mu\text{g/g}$ which is $<0.001 \text{ g per metric ton}$ of ammonium sulfate product. Assuming a coal generates 2500 ppm SO_2 , the mercury in the ammonium sulfate product represents only 0.05% of the total mercury generated during coal combustion. The remaining 99.95% exits the system via the ESP hopper ash, the stack, the liquid portion of the FGD slurry, and the insoluble portion of the slurry solids. To do a complete Hg balance around the system, a much more detailed study would need to be completed.

7.0 CONCLUSIONS AND RECOMMENDATIONS

For the pilot-scale tests evaluating the ability of a wet ESP to remove particulate matter following an MET NH_3 -based FGD system, the following conclusions/observations were made.

7.1 Test Series I

- The overall particulate removal efficiency of the wet ESP averaged about 70%. From these data, it is clear that the wet ESP configuration used in Test Series I did not achieve the desired 90% control.
- The current density of the wet ESP was lower than expected. Based on this result, modifications to the wet ESP electrodes and configuration were made prior to Test Series II.
- There was an increase in flue gas particulate concentration across the MET NH_3 -based FGD system. Based on the sulfate and ammonia concentrations and the overall mass balance, the increase in particulate matter across the MET NH_3 -based FGD system is due to the reaction of SO_3 with NH_3 .
- The mass balance ratios between NH_3 and SO_3 indicated that the particulate matter at the exit of the MET NH_3 -based FGD system is mostly $(\text{NH}_4)_2\text{SO}_4$, but reactions resulting in the formation of NH_4HSO_4 are also occurring.
- As a result of the small design SCA, the particle collection efficiency of the dry ESP was low.
- The particulate matter at the outlet of the MET NH_3 -based FGD system is extremely small, with a great percentage of the particles $<0.3 \mu\text{m}$. This, again, indicates that the particulate matter was formed as a result of reaction products.

- Vapor-phase SO₃ concentration was at or near zero at the outlet of the MET NH₃-based FGD system.
- Virtually all of the vapor-phase chlorides in the flue gas were removed by the MET NH₃-based FGD system.
- The SO₂ and NO_x removal efficiency across the MET NH₃-based FGD system was 88% and 13%, respectively.
- There was about a 25% air leak across the dry ESP.
- The wet ESP wall heaters needed to be turned off to prevent a temperature increase across the unit, resulting in wall drying.
- Overall conditions (flue gas composition, pressures, and temperatures) were relatively stable during the test.
- The mercury speciation concentration in the flue gas was 92% oxidized mercury. As a result, 92% of the total mercury was removed by the MET NH₃-based FGD system, with an additional 7% removed by the wet ESP.
- The dry ESP inlet dust loading was lower firing the SFS compared to a standard pc-fired boiler when the Robinson Run coal was fired. The dust loading was approximately one-fourth of what would be expected.

7.2 Test Series II

Many of the same operational conclusions or observations made in Test Series I also were true for Test Series II. For example, the air leakage across the dry ESP and the dry ESP inlet dust loading were about the same. Conclusions and observations reached as a result of Test Series II are as follows:

- After modification of the wet ESP electrode mast and the wet ESP fields, much higher current levels were obtained compared to Test Series I.
- For all tests during which the wet ESP did not spark/trip, >90% particulate removal efficiency was obtained.
- The coal and petroleum coke were the same as used for Test Series I based on the analysis of the two fuels.
- With humidification, particulate removal efficiency across the dry ESP was improved, and as a result, the overall particulate removal efficiency of the system was greatly enhanced.

- The average particle size of the bulk fly ash was increased as a result of humidification. This may explain the increase in particulate removal efficiency of the dry ESP.
- As was the case for Test Series I, the particulate matter exiting the MET NH₃-based FGD system appears to be NH₃ and SO₃ reaction products.
- Based on very limited data, the mercury concentration in the (NH₄)₂SO₄ solids appears to be very low.
- Although a much more complete evaluation needs to be done, corrosion in the wet ESP may be a problem. The pH of the wash solution was very low, ~1 or less.

8.0 REFERENCES

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