EXHIBIT 1

Table ES-4: Capital and Operating Cost Summary – Including Unit 1

Control Systems (Units 1-3)	Capital Requirement[1, 4]		First –Year Costs			Levelized Cost[3]
			Fixed O&M[1]	Variable O&M[2]	Fixed Charges[1]	
	$1,000	$/kW	$1,000/yr	$1,000/yr	$1,000/yr	$/ton rem.
LSFO – relined[5]	$377,180	$530	$16,600	$720	$78,260	$4,250
LSFO – new[5]	$412,600	$580	$17,110	$720	$85,610	$4,580
Advatech[6]	N/A	N/A	N/A	N/A	N/A	N/A
LSD+FF	$410,460	$580	$14,140	$1,620	$85,170	$4,640
CFB+FF	$399,440	$560	$12,060	$1,950	$82,880	$4,360
DSI+FF	$280,440	$400	$7,210	$8,910	$58,190	$5,610
SCR (U1)	$45,660	$390	$670	$910	$9,470	$11,610
Mobotec (U2)	$11,260	$40	$380	$840	$2,340	$4,790

1 = Cost based on design coal. $/kW based on 707 net MW.

2 = Cost based on operating coal.

3 = Total First Year and Total Levelized cost is the sum of fixed charges, fixed O&M cost, and variable O&M cost. "Tons removed" is based on operating coal and are for SO_2 for all cases except SCR and Mobotec, which is based on NO_X. Levelized cost represent an annualized cost over the life of the plant.

4 =Capital costs include a new chimney for Unit 1 for all FGD technologies.

5 = Relined Unit 3 chimney to discharge flue gas from Units 2 and 3. New chimney to discharge flue gas from Units 2 and 3.

6 = Advatech did not supply cost for all three units.

Table ES-4: Capital and Operating Cost Summary for 6-Unit AQCS Options

Alternative		Total Capital Requirement[1]		First Year Fixed Charges[1]	First Year Fixed O&M[1]	First Year Variable O&M[2]	Total First Year Cost[3]	Total Levelized Cost[3]
		$1000	$/kW	$1000	$1000	$/MWh	$/ton removed	$/ton removed
Cost Year Basis		2011	2011	2011	2011	2011	2011	20 Year Life
LSFO: Pre-gnd	6 Units	$404,500	$400	$77,800	$18,000	$0.62	$3,390	$3,130
LSFO: Crushed	6 Units	$418,600	$410	$80,500	$18,500	$0.37	$3,420	$3,200
Advatech	6 Units							
SDA+FF	6 Units	$459,300	$450	$88,400	$18,700	$0.99	$3,980	$3,690
CFB + FF	6 Units	$415,100	$410	$79,900	$15,100	$1.08	$3,510	$3,270
FDA + FF	6 Units	$392,600	$380	$75,500	$13,600	$1.00	$3,440	$3,230
DSI + FF	6 Units	$344,500	$300	$66,300	$9,000	$3.50	$6,500	$6,390
ReACT	6 Units	$410,000	$400	$78,900	$18,200	$0.90	$3,400	$3,200
SCR	6 Units	$271,800	$270	$52,300	$3,800	$0.46	$20,800	$18,300

1) Cost based on Design Coal
2) Cost based on Operating Coal
3) Total First Year and Total Levelized dollars is sum of Fixed Charges, Fixed and Variable O&M costs. Tons removed is based on Operating Coal conditions for $/ton removed calculation. For all except SCR, based on tons of SO_2 removed. SCR based on tons of NOx removed.

Table ES-2: Capital and Operating Cost Summary for 3-Unit AQCS Options

Alternative		Total Capital Requirement[1]		First Year Fixed Charges[1]	First Year Fixed O&M[1]	First Year Variable O&M[2]	Total First Year Cost[3]	Total Levelized Cost[3]
		$1000	$/kW	$1000	$1000	$/MWh	$/ton removed	$/ton removed
	Cost Year Basis	2011	2011	2011	2011	2011	2011	20 Year Life
LSFO: Pre-ground	3 Units	$228,300	$450	$43,900	$10,500	$0.60	$3,820	$3,570
LSFO: Crushed	3 Units	$236,500	$460	$45,500	$10,900	$0.35	$3,880	$3,570
Advatech	3 Units							
SDA + FF	3 Units	$228,000	$450	$43,900	$10,000	$0.97	$4,010	$3,760
CFB + FF	3 Units	$204,100	$400	$39,300	$8,200	$1.06	$3,500	$3,300
FDA + FF	3 Units	$195,100	$380	$37,500	$7,400	$1.00	$3,480	$3,260
ReACT	3 Units	$218,700	$430	$42,100	$10,400	$0.90	$3,650	$3,470
SCR	2 Units	$101,000	$300	$19,500	$1,500	$0.46	$23,400	$20,600

1) Cost based on Design Coal
2) Cost based on Operating Coal
3) Total First Year and Total Levelized dollars is sum of Fixed Charges, Fixed and Variable O&M costs. Tons removed is based on Operating Coal conditions for $/ton removed calculation. For all except SCR, based on tons of SO_2 removed. SCR based on tons of NOx removed.

EXHIBIT 2

Electric Energy, Inc.

The Shaw Group Inc.®

Joppa Generating Station

EEI Joppa Generating Station Dry Sorbent Injection Test Program

Draft Final Report

September 8, 2010

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Abbreviations and Acronyms

AH	Air heater
ASTM	American Society for Testing and Materials
Btu	British Thermal Units
CEM	Continuous emission monitor
CFR	Code of Federal Regulations
CO_2	Carbon dioxide
CPM	Condensable particulate matter
CTM	Conditional Test Method
d.d.	Duct diameter
DI	Distilled or deionized
dNm^3	Dry normal cubic meter
DSI	Dry sorbent injection
ESP	Electrostatic precipitator
ft^3 or cu ft	Cubic foot
h or hr	Hour
HCl	Hydrochloric acid
HF	Hydrogen fluoride
Hg	Mercury
Hg OHM	Mercury Ontario hydro method
Hg App K	Mercury appendix K (method)
Hgp	Particle-bound mercury
Hg^0	Elemental mercury
Hg^{2+}	Oxidized mercury
HNO_3	Nitric acid
H_2O_2	Hydrogen peroxide
H_2SO_4	Sulfuric acid
ICR	Information collection request
KCl	Potassium chloride
$KMnO_4$	Potassium permanganate
lb	Pound
LCS	Laboratory control sample
M5	Test Method 5
mg	Milligram
min	Minute
mL	Milliliter
mm	Millimeter
mmacf	Million actual cubic feet

MMBtu	Million BTUs
MWh or MW-hr	Megawatt hour
cu m or m^3	Cubic meter
ug	Microgram
NaOH	Sodium hydroxide
NCASI	National Council for Air and Stream Improvement
NH_3	Ammonia
NO_2	Nitrogen dioxide
O_2	Oxygen
PAC	Powdered activated carbon
PJFF	Pulse-jet fabric filter
PM	Particulate matter
PM10	Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 microns as measured by applicable test or monitoring methods
PM2.5	Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns as measured by applicable test or monitoring methods
ppmv	Parts per million by volume
PRB	Powder River Basin (coal)
QC	Quality control
reps	Replicates
RPD	Relative percent difference
SBC	Sodium bicarbonate
Shaw E&I	Shaw Environmental & Infrastructure, Inc.
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
TAL	Target analyte list
TCLP	Toxic characteristic leaching procedure
TM	Test method
tsf	Ton per square foot

Executive Summary

Electric Energy, Inc (EEI) commissioned The Shaw Group (Shaw Power and Shaw Environmental & Infrastructure, collectively Shaw) to determine whether Dry Sorbent Injection (DSI) in front of the existing electrostatic precipitators (ESP)s would be successful in removing 50% or more of the SO_2 in the gas stream without detrimentally impacting the operation of the ESPs and fly ash handling system.

The scope of work presented a 10 day test program to determine the optimum location of DSI (before or after the air heaters), the condition the DSI (Trona or sodium bicarbonate) should be injected as (milled or un-milled), and the DSI rate (lbs/hr needed to achieve 50% SO_2 removal).

Study objectives included:

- whether continuous 50% or better SO_2 reduction and continuous 90% mercury removal can be achieved during normal plant operations including turn down of the units due to market demands;
- whether the use of a dry sorbent will impact the level of acid gases and heavy metals in the flue gas;
- whether there is an impact to the air heaters if the selected DSI point was located upstream of the air heaters;
- whether there is an impact to the ESP from either DSI reagent
- whether there is an impact to the operation of the fly ash handling system, and;
- whether there are any issues in the handling of DSI that would cause undue hardship on the plant operation.

The study was a collaborative effort among several entities. Overall direction was provided by EEI with support from Shaw who provided flue gas testing, solids testing, program coordination support, and data analyses and reporting. Solvay provided the dry sorbent, and NolTec provided the dry sorbent unloading and feed equipment and equipment operators.

The conduct of the study occurred over a three week period from June 1 – 16, 2010. Changes to the original program design were made as the program progressed in the field. Changes were judged necessary given data as it was reviewed, or in some cases changes were made because it was judged that results would not be meaningful. These changes are highlighted in the report.

From the data collected the following general conclusions can be made:

- **SO_2 removal of 50% can be achieved using DSI**
    - Greater than 50% SO_2 removal was obtained with un-milled Trona and milled Trona before the air heater and with sodium bicarbonate (SBC) before or after the air heater.
    - 50% removal was not seen with milled Trona injecting after the air heater.

- **SBC was more efficient than Trona for removing SO_2**
    - SBC had a better utilization efficiency than Trona whether milled or un-milled with a 0.158 lbs SO2 removed per lb of dry sorbent versus 0.100 lbs SO2 removed per lb of dry sorbent for milled Trona when injection was before the air heaters.
    - Milled Trona was marginally more efficient than un-milled Trona in SO_2 removal (ratio averages 0.100 vs. 0.093, lbs SO2 removed per lb of dry sorbent respectively) when injected before the air heater.

- **Injection upstream of the air heaters improves sorbent utilization**
    - The injection location (whether before or after the air heater) impacts the efficiency of Trona and SBC utilization, with injection before the air heater having a greater utilization efficiency.
    - When using SBC for 50% SO_2 removal, a utilization rate of about 0.12 lbs SO_2 removed per lb of SBC is needed with injection after the air heater and a significantly greater utilization (>0.158 lbs SO2 removed per lb of dry sorbent) if injection is before the air heater.
    -
- **DSI will reduce acid gases but no impact on heavy metals was seen**
    - About 80% removal was seen for HCl and HF

- **DSI will trigger PSD**
    - The addition of a dry sorbent to the flue gas trains will result in an increase in the particulates (both total PM and PM10) leaving the stack, to the point that Prevention of Significant Deterioration (PSD) regulations would be applied to the plant modification due to exceeding the “significant net emission” threshold for particulate emissions. Upgrades to the plant ESPs would be required to offset this increase in particulates.

- **DSI by-product can be landfilled but will require system upgrades**
    - The increase in fly ash generated with DSI will require increased capacity of the fly ash handling system’s daily operation, and/or additional storage.
    - The by-product handling operation and landfill operation will require the following:
        - The by-product should be wetted in a two stage approach where a portion of the water is added at the dustless unloader for dust

control and the remaining water needed for optimum compaction be added at the landfill via a water truck or like conveyance system.

- The runoff pH will likely be high enough to require neutralization of the landfill pond runoff prior to discharge.
- The landfilled material will need to be managed (covered) to minimize standing water on the by-product due to its potential dissolution. The dissolution will increase the total dissolved solids in the landfill runoff potential to a point impacting its discharge permit and potentially the landfill integrity over the life of the landfill.

- **No significant impact on the air heaters or ESPs observed**
  - No increase in air heater pressure drop was observed when injecting either SBC or Trona upstream of the air heaters.
  - ESP % removal performance and stack opacity did not change when injecting either sorbent and firing East Thunder coal. Some affect was observed when firing Belle Ayr coal. Due to increased inlet loading, the additional outlet loading was enough to trigger PSD.

- **DSI will significantly increase O&M costs**
  - Based on a delivered cost of \$175/ton for Trona and \$200/ton for SBC the annual reagent cost assuming that the plant were to operate at 90% capacity factor burning a 0.61 lb/MMBtu SO_2 coal with 50% SO_2 removal and DSI before the air heater is about \$16,000,000/yr. See the summary cost table below for relative cost of Trona and alternative injection locations.

Estimated Annual Cost of Dry Sorbent For 50% SO2 Removal

Dry Sorbent	Injection Location	Dry Sorbent Cost (\$/ton)	Lb SO_2 removed per lb of Dry Sorbent	Yearly Cost of Dry Sorbent (1)
Un-milled Trona	Before Air heater	\$ 175	0.093	\$ 23,483,829
Milled Trona	Before Air heater	\$ 175	0.10	\$ 21,839,961
Milled Trona	After Air heater	\$ 175	0.049 (2)	\$ 44,571,349 (2)
SBC	Before Air heater	\$ 200	0.16 (3)	\$ 15,599,972 (3)
SBC	After Air heater	\$ 200	0.12	\$ 20,799,963

Notes:

1. Based on 50% SO_2 removal with plant burning PRB coal with 0.61 lbs of SO_2/MMBtu and a yearly plant capacity factor of 0.90
2. The data for milled Trona injection after the air heater is minimal. This utilization rate achieved an average of 42.6% SO_2 removal. The utilization rate would likely be higher to achieve 50% removal, so the yearly estimated cost would likely be higher than shown to achieve 50% SO_2 removal.

3. The data for SBC injection before the air heater is minimal. This utilization rate achieved an average of 67% SO_2 removal. The utilization rate would likely be lower to achieve 50% removal, so the yearly estimated cost would be lower than shown to achieve 50% SO_2 removal

The following recommendations can also be made:

- **Estimate the cost of particulate control upgrades for DSI options**
    - Evaluate unmilled Trona injected before the air heater with ESP upgrades to address current regulations and not trigger PSD (high risk alternative), since un-milled Trona may have less of an impact on particulate emissions than other dry sorbents.
    - Evaluate other DSI options and address future utility MACT rules by adding a helper ESP or a fabric filter downstream of the existing ESP.

- **Perform economic engineering evaluation of SO_2 control technologies for the Joppa Station**
    - Design criteria in line with expected utility MACT regulations for evaluating different options:
        - DSI with helper ESPs and fabric filters
        - Wet flue gas desulfurization
        - Dry flue gas desulfurization
        - ReACT

If the use of DSI at Joppa is still viable after the review of ESP efficiency upgrades, then additional testing is warranted that would include:

- Prolonged injection of each reagent upstream of the air heaters to determine potential long term impacts
- Testing on both Units 5 and 6 so that the stack CEMs can be utilized versus induct sampling.
- Additional mercury testing should be included

- It would be beneficial for Joppa to conduct a full PSD analysis at the conclusion of CY2010 operation using the latest emission data.

1 Introduction

Electric Energy, Inc (EEI) commissioned The Shaw Group (Shaw Power and Shaw Environmental & Infrastructure, collectively Shaw) to determine whether Dry Sorbent Injection (DSI) in front of the existing electrostatic precipitators (ESP)s would be successful in removing 50% or more of the SO_2 in the gas stream without detrimentally impacting the operation of the ESPs and fly ash handling system.

The scope of work developed jointly by EEI and Shaw was a high level test program. It presented a 10 day test program to determine the optimum location of DSI (before or after the air heaters), the condition the DSI (Trona or sodium bicarbonate) should be injected as (milled or un-milled), and the DSI rate (lbs/hr needed to achieve 50% SO_2 removal).

At the completion of parametric testing on Unit 6, Units 5 and 6 were tested with flue gas testing being performed in the combined stack. This performance testing was to last up to 5 days on a continuous 24 hour basis to determine:

- whether continuous 50% or better SO_2 reduction and continuous 90% mercury removal can be achieved during normal plant operations including turn down of the units due to market demands;
- whether there is an impact to the air heaters (if upstream of the air heaters was the selected DSI point);
- whether there is an impact to the ESP from either DSI reagent
- whether there is an impact to the operation of the fly ash handling system, and;
- whether there are any issues in the handling of DSI that would cause undue hardship on the plant operation.

1.1 Joppa Station

The Joppa Generating Station is a six unit coal fired power plant located at 2100 Portland Road, in Joppa Illinois. The station is located on the Ohio River. Each unit is rated for 181 MW. The plant was commissioned between 1953 and 1955. The plant is currently burning various Powder River Basin Coals.

The Joppa station is operated by Electric Energy Inc., an independent power producer, and is owned by Ameren (80%) and Kentucky Utilities (20%).

The plant’s capacity factor is historically greater than 92% inclusive of all planned and forced outages. Normally, all six units are continuously operating at or near their capacity. Therefore, it is imperative that any backend environmental controls implemented at the site are robust and the designs are redundant so as to be highly reliable and not cause forced outages of the plant technology.

The plant is currently equipped with a SO_3 injection systems for flue gas conditioning (fly ash resistivity treatment) and activated carbon injection systems for mercury removal. (The SO_3 injection system was not active during this test program.)

1.2 Division of Responsibility

The study was a collaborative effort among several entities. Overall direction was provided by EEI with support from Shaw, Solvay, and NolTec. The general Division of Responsibilities was as follows:

EEI

- Overall program management
- Plant operations
- Obtain permits / approvals from IEPA
- Obtain reagents and arrange delivery
- Obtain experimental injection equipment and operating services
- Provide plant tie-ins including injection sites, electrical power and trailer space
- Provide office space, conference room and sanitary facilities
- Obtain coal and byproduct samples
- Provide PI data output

Shaw (Shaw Power and Shaw E&I)

- Assist EEI with test program development
- Perform flue gas testing
- Obtain laboratory analysis of solid media
- Perform a characterization study of byproduct materials
- Provide assistance with overall coordination
- Data analysis
- Draft and final reports

NolTec Systems

- Provide, install and demobilize DSI storage, milling and injection equipment
- Provide operators for their equipment
- Record feed rates
- Analyze reagents

Solvay Chemicals

- Arrange for the procurement and delivery of reagents
- Provide consultation on use of reagents

2 Conduct of the Study

2.1 Experimental Design

The study objectives were:

- demonstrate 50% SO_2 removal using DSI
- determine effect of DSI on mercury removal
- determine effect on ESP performance and outlet particulate emissions and opacity
- quantify any changes in certain pollutants including acid gases and some metals
- determine byproduct characteristics to assist with landfill operations; and
- assess the impact of overall operation on plant equipment and infrastructure.

The conduct of the study as it was performed over portions of three weeks is shown in Table 2-1. Some changes were made from the original design as the program progressed in the field. Changes were judged necessary given data as it was reviewed or in some cases, changes were made because it was judged that results would not be meaningful.

Sample point locations consisting of single point sampling included the following locations:

- Economizer Outlet - consisted of two parallel ducts (Duct A & B) each with a cross sectional area of 230 square feet at the sampling location.
- ESP Inlet - consisted of two parallel ducts (Duct A & B) each with a cross sectional area of 230 square feet at the sampling location.
- ESP Outlet - consisted of two parallel ducts (Duct A & B) each with a cross sectional area of 250 square feet at the sampling location.
- Common #3 Tall Stack - single annular stack with an 18 foot diameter at the sampling location.

Selection of the sampling point at each location was based on first traversing each location taking flow and temperature readings and selecting the point most representative for that location. This sampling methodology, though not totally consistent with EPA sampling protocols, was chosen based on cost considerations and the comparative analyses needed for this engineering study.

All CEMS (e.g. O_2, CO_2, NO_X) measurements were conducted at a single point centrally located inside Duct A of each designated sampling location, simultaneously with each wet chemistry method (e.g. PM, Hg). Wet chemistry sampling trains were located at the common #3 Tall Stack and a single centralized location inside Duct B of each sampling location .

Table 2-1 - DSI Test Program
(as performed)
Units 5 and 6 - Joppa Station

Date	Test Day	Purpose	Injection location	Reagent Injected	Sampling	Additional Information
June 1,2,3 Tuesday		Travel and mobilization, Setup injection and test equipment	NA	NA	NA	NA
June 4 Friday	1	Baseline testing.	NA	None	Two runs. Unit 6. CEMs in/out; OHM in/out; PM in/out; stack-OHM, TM29, TM26A, TM8A; TM30B. Coal, ash, byproduct.	Test coal at ~1 lb SO_2/MMBtu . 5 lb AC/Macf. No DSI. No SO_3 injection.
June 5 Saturday	2	Baseline testing.	NA	None	Two runs. Unit 6. CEMs in/out; OHM in/out; PM in/out; stack-OHM, TM29, TM26A, TM8A; TM30B. Coal, ash, byproduct.	Test coal at ~1 lb SO_2/MMBtu . 5 lb AC/Macf. No DSI. No SO_3 injection.
June 7 Monday	3	Un-milled Trona injection	Upstream of air heater	Trona	Three runs. CEMs in/out; OHM in/out; PM in/out.	Determine un-milled Trona injection rate for 50% reduction.
June 8 Tuesday	4	Milled Trona injection	Upstream of air heater	Trona	Three runs. CEMs in/out; OHM in/out; PM in/out.	Determine milled Trona injection rate for 50% reduction. Onsite milling.
June 9, Wednesday	5	Milled Trona Injection	Down-stream of air heater	Trona	Morning runs. CEMs (only) in/out	Determine milled Trona injection rate for 50% reduction. Onsite milling.

Table 2-1 - DSI Test Program
(as performed)
Units 5 and 6 - Joppa Station

Date	Test Day	Purpose	Injection location	Reagent Injected	Sampling	Additional Information
June 9, Wednesday	5	Pre-milled SBC injection	Down-stream of air heater	SBC	Afternoon runs. CEMs (only) in/out	Determine SBC injection rate for 50% reduction
June 10 Thursday	6	Pre-milled SBC injection	Upstream of air heater	SBC	Three runs. CEMs in/out; OHM in/out; PM in/out.	Determine SBC injection rate for 50% reduction.
June 11, Friday	7	Pre-milled SBC injection	After air heater	SBC	Units 5 & 6. Three runs. CEMs (only) in/out	Parametric study to determine SO_2 reduction at varying feed rates.
June 14, Monday	8	Pre-milled SBC injection	After air heater	SBC	Units 5 & 6. Three runs. CEMs (only) in/out (stack CEMs)	Determine SBC injection rate for 50% reduction, two unit injections.
June 15 Tuesday	9	Pre-milled SBC injection	After air heater	SBC	Three runs. Unit 5&6. CEMs in/out; OHM in/out; PM in/out; stack-OHM, TM29, TM26A, TM8A; TM30B. TM5 and 202; Coal, ash, byproduct (5 x 5 gallons).	
June 16, Wednesday		Testing terminated due to Unit 5 tube leak outage.				

2.2 Reagent Characteristics

2.2.1 Trona

Trona is derived from sodium sesquicarbonate rock. Its formula is $Na_2CO_3.NaHCO_3.2H_2O$. The rock is typically milled and delivered at a fineness of 30 – 35 microns. Typical moisture of delivered product is 0.03%. (SOLVAY, 2010). Delivery sheets are found in Attachment 5.

Trona materials were secured from Solvay Chemicals, Inc, Houston, Texas. The product is identified as: SOLVAir Select 200 BULK (Material Code 60178). Customer Specification Number is SS200-0108. Characteristics of Trona as delivered comes from truck invoices, as follows:

Table 2-2 – Trona Characteristics as Delivered

Rail Car ACFX045644 – Two loads reported				
	Result	Unit	Minimum	Maximum
Wet Trona	97.3	%	95.0	
Free Moisture	0.02	%		0.07
D(50)	31	Micron		46
+70 Micron	27	%		
Rail Car ACFX051251 – Two loads reported				
	Result	Unit	Minimum	Maximum
Wet Trona	97.6	%	95.0	
Free Moisture	0.03	%		0.07
D(50)	39	Micron		46
+70 Micron	32	%		
Rail Car SHPX450385 – One load reported				
	Result	Unit	Minimum	Maximum
Wet Trona	96.9	%	95.0	
Free Moisture	0.02	%		0.07
D(50)	41	Micron		46
+70 Micron	33	%		
Rail Car ACFX045451 – One load reported				
	Result	Unit	Minimum	Maximum
Wet Trona	97.8	%	95.0	
Free Moisture	0.02	%		0.07
D(50)	46	Micron		46
+70 Micron	36	%		

On certain days, onsite milled Trona was used for injection. Particle size analysis was conducted by Sturtevant from samples provided by NolTec. Laboratory data are provided in Attachment 5. The "as delivered" Trona had a D50 of 39 microns. The milled Trona had a measured D50 of 26 microns.

2.2.2 Sodium Bicarbonate (SBC)

Sodium bicarbonate is a downstream product made from Trona. Its formula is $NaHCO_3$. Pre-milled materials are delivered at D_{90} of < 40 microns. In literature, Solvay recommends onsite milling to <20 microns prior to injection (Solvay, 2010. Dry Sorbent Injection of Sodium Sorbents. Emissions Control and Measurement Workshop. March 24-25, 2010).

The pre-milled SBC materials were secured from Solvay Chemicals, Inc, Houston, Texas. The product is identified as: BIR SOLVAIR SELECT 350 HNM BULK (Solvay Material Code 65591) also known as SOLVAIR 350 BULK. The trucks delivering the product were loaded from bulk bags which had been storing the pre-milled SBC.

Material Certifications provided with each delivery had descriptions –

Customer Material Specification:
Sodium, as Na >= 27.00 %
Sodium Bicarbonate, as $NaHCO_3$ = 99.0 – 100.50%
Screen Analysis % Retained…
US 200 (75 micron) 20 – 100%
US 325 % (45 micron) 60 - 100%
.

It should be noted that much of the delivered SBC had clumps of material within the delivered bulk causing unloading problems. These clumping and unloading problems were not seen with the delivered un-milled Trona. Certifications are provided in Attachment 5.

2.3 NolTec DSI Feed Equipment

The DSI system was "Sorb-N-Ject" provided by NolTec Systems, Lino Lakes, MN. (Drawings and additional information on the NolTec provided system can be found in Attachment 3.) The system had one portable free standing storage silo. The silo capacity was 1450 cu ft. The silo had load cells for monitoring weight loss of materials. Weight loss as a function of time was used in the field to quantify the feed rate. When filling, a bin vent filter controlled dust from displaced air and material transport air. Feed was controlled by dual-speed adjustable rotary feeders. The silo was filled, as needed, by bulk carrier trucks. Trucks generally contained 45,000 – 50,000 pounds of material. Silo fill time was about one hour when there was no reagent clumping.

A portable blower trailer was also provided. The design capacity of the sorbent feed system was 20,000 lb/hr. The blowers were positive displacement rotary blowers driven by a 40 HP motor. Each blower was capable of providing 500 scfm at 11.5 psig. The system included a heat exchanger, conveying piping and injection lances. The trailer also housed control and electric supply equipment and operator space.

The in-line milling system was designed for use with Trona. The Sturtevant Simpactor was a centrifugal, pin-type impact mill. The system had dual plate rotor with one row of pins.

NolTec provided lances were inserted above the air heater (one unit) and below the air heater (two units). They were straight pipes with flat, cutoff ends. Lances were inserted at staggered lengths before the air heater The lances after the air heater were all the same length..

2.4 Coal

During the performance of the test program, the plant burned two Powder River Basin (PRB) coals; East Thunder (Jacobs Ranch) and Belle Ayr. The significant difference between these two coals was sulfur content with the Jacobs Ranch coal having almost twice the sulfur content with 1.07 lbs/MMBtu SO_2 versus 0.58 lb/MMBtu SO_2 for the Belle Ayr coal. The mercury concentration in the Jacobs Ranch coal was also higher. Table 2-3 presents the analyses of the daily samples of the coals. It should be noted that for coal utilization, the sample was taken near the end of that day’s testing.

Table 2-3 - Coal Analyses Results

Coal Source	Sample day	Btu/lb	Ash %	Ash lb/ MMBtu	S %	SO_2 lb/ MMBtu	Cl %	As ppm	Ba ppm	Cd ppm	Cr ppm	Pb ppm	Se ppm	Ag ppm	Hg ppm	Hg lb/ TBtu
Jacobs Ranch	6/2/10	8420	5.96	14.16	0.48	1.14	0.02	3.01	302	<1	6.65	3.16	<2	1.5	0.129	15.32
Jacobs Ranch	6/3/10	9150	6.79	14.84	0.49	1.07	0.02	2.48	307	<1	6.5	2.43	<2	1.5	0.097	10.60
Jacobs Ranch	6/4/10	8420	5.85	13.90	0.5	1.19	0.01	<2	308	<1	6.21	2.14	<2	1.49	0.098	11.64
Jacobs Ranch	6/5/10	8370	5.5	13.14	0.48	1.15	0.02	<2	315	<1	6.0	3.2	<2	1.47	0.099	11.83
Jacobs Ranch	6/6/10	8710	5.64	12.95	0.44	1.01	0.02	<2	300	<1	5.91	1.65	<2	1.8	0.111	12.74
Jacobs Ranch	6/7/10	8630	5.7	13.21	0.49	1.14	0.01	2.21	344	<1	5.92	2.29	<2	1.68	0.081	9.39
Jacobs Ranch	6/8/10	7840	5.17	13.19	0.35	0.89	0.01	<2	377	<1	6.54	2.61	<2	1.59	0.131	16.71
Jacobs Ranch	6/9/10	8390	6	14.30	0.43	1.03	0.02	<2	321	<1	6.38	2.27	<2	1.46	0.103	12.28
Jacobs Ranch	6/10/10	8470	5.63	13.29	0.45	1.06	0.02	<2	311	<1	6.24	2.72	<2	1.27	0.113	13.34
Jacobs Ranch	6/11/10	8430	5.79	13.74	0.45	1.07	0.02	<2	330	<1	5.9	2.49	<2	1.7	0.164	19.45
Combination?	6/12/10	8390	5.02	11.97	0.36	0.86	<0.01	<2	307	<1	5.52	2.05	<2	1.42	0.151	18.00
Belle Ayr	6/13/10	8380	5.04	12.03	0.24	0.57	<0.01	<2	355	<1	4.94	1.66	<2	1.4	0.085	10.14

Table 2-3 - Coal Analyses Results

Coal Source	Sample day	Btu/lb	Ash %	Ash lb/ MMBtu	S %	SO_2 lb/ MMBtu	Cl %	As ppm	Ba ppm	Cd ppm	Cr ppm	Pb ppm	Se ppm	Ag ppm	Hg ppm	Hg lb/ TBtu
Belle Ayr	6/14/10	8350	5.11	12.24	0.23	0.55	0.02	<2	319	<1	4.63	1.72	<2	1.62	0.083	9.94
Belle Ayr	6/15/10	8510	4.59	10.79	0.26	0.61	0.01	<2	295	<1	4.31	2.19	<2	1.42	0.071	8.34
Averages																
Jacobs Ranch		8483	5.80	13.67	0.46	1.07	0.017	<2.17	322	<1	6.23	2.50	<2	1.55	0.113	13.27
Belle Ayr		8413	4.91	11.69	0.24	0.58	<0.013	<2	323	<1	4.63	1.86	<2	1.48	0.080	9.47
Percent Belle Ayr of Jacobs Ranch		99.18	84.7	85.5	53.4	53.84	76.47	92.2	100.5	100	74.3	74.4	100	95.7	70.75	71.34

3 Test Program Results

The experimental design for the program is described in Section 2.1. The program considered two reagents, Trona and Sodium Bicarbonate (SBC). Trona was injected into duct work at as delivered particle size and after onsite milling. SBC was injected as received. SBC was milled prior to shipping to the site. However, there was some clumping of the SBC in the bulk delivery vehicles. Trona was injected both upstream (un-milled and milled) and downstream (milled) of the air heater (AH). SBC was also injected both upstream and downstream of the air heater. The feed rates of the DSI were varied throughout the test program with the general intent to achieve 50% SO_2 removal and to determine DSI utilization trends versus SO_2 removal. Table 3-1 provides the average DSI feed rates used throughout the tests. These average feed rates are based on the NolTec DSI storage cell load cell readings which are provided in Attachment 6. It should be noted that during some of the test runs DSI was added to the storage cell resulting in unusable load cell readings. During these occasions airlock speeds were used to estimate average DSI rates based on available data near the time of the silo feeding event..

Table 3-1 - Average Dry Sorbent Injection Rates Per Test Event

Date	Run	Start time	End Time	DSI	Injection Location	Average Injection Rate (LB/Hr)	Comments
4-Jun				None	NA	NA	Baseline Testing
5-Jun				None	NA	NA	Baseline Testing
7-Jun	1	12:00	13:00	Un milled Trona	Before air heater – Unit 6	5,971	
7-Jun	2	15:15	17:00	Un milled Trona	Before air heater – Unit 6	11,659	
7-Jun	3	18:00	18:34	Un milled Trona	Before air heater – Unit 6	10,219	
8-Jun	1	9:45	10:47	Milled Trona	Before air heater – Unit 6	8,838	
8-Jun	2	12:29	13:35	Milled Trona	Before air heater – Unit 6	8,561	
8-Jun	3	15:21	16:21	Milled Trona	Before air heater – Unit 6	8,688	
9-Jun	1	10:52	12:31	Milled Trona	After air heater – Unit 6	14,237	
9-Jun	2	15:27	16:00	Pre-milled SBC	After air heater – Unit 6	11,643	
10-Jun	1	10:00	11:03	Pre-milled SBC	Before air heater – Unit 6	7,733	
10-Jun	2	12:45	13:50	Pre-milled SBC	Before air heater – Unit 6	7,275	

Table 3-1 - Average Dry Sorbent Injection Rates Per Test Event							
Date	**Run**	**Start time**	**End Time**	**DSI**	**Injection Location**	**Average Injection Rate (LB/Hr)**	**Comments**
10-Jun	3	15:20	16:27	Pre-milled SBC	Before air heater – Unit 6	6,921	
11-Jun	1	11:23	11:52	Pre-milled SBC	After air heater - Units 5 and 6	5,882	
11-Jun	2	12:14	13:31	Pre-milled SBC	After air heater - Units 5 and 6	11,077	
11-Jun	3	16:14	17:31	Pre-milled SBC	After air heater - Units 5 and 6	14,665	SBC added to silo during test, usage estimates were based on feed valve speed
14-Jun	1	9:53	12:38	Pre-milled SBC	After air heater - Units 5 and 6	9,284	SBC added to silo during test, usage estimates were based on feed valve speed
14-Jun	2	13:05	17:07	Pre-milled SBC	After air heater - Units 5 and 6	9,683	SBC added to silo during test, usage estimates were based on feed valve speed
15-Jun	1	8:50	9:50	Pre-milled SBC	After air heater - Units 5 and 6	10,200	SBC added to silo during test, usage estimates were based on feed valve speed
15-Jun	2	12:15	13:33	Pre-milled SBC	After air heater - Units 5 and 6	9,956	
15-Jun	3	14:59	16:08	Pre-milled SBC	After air heater - Units 5 and 6	10,438	

3.1 Air Emissions Test Results

This section presents summary results of air emissions test data. Details of the test performed are found in Attachment 1. The plant's SO_3 injection flue gas conditioning system was taken out of service for all tests. Trona, like SO_3, is also used to increase the conductivity of fly ash for removal in ESPs. Trona would also remove the SO_3 before it would be effective. The plant's PAC injection mercury control system remained in operation. PAC was injected at a minimum of 5 lb of PAC/mmacf. At the time of the DSI Test Program, PAC was injected upstream of the air heaters on Units 5 and 6. Plant PI data records were secured during all tests to document plant loads and performance during the test date.

3.1.1 Baseline program

The purpose of the base line program was to document emissions and plant operating characteristics prior to reagent injections. The results from the test injections are compared to the baseline as appropriate.

Baseline testing occurred June 4 and 5. Two test runs were performed on each of the two days. The plant was burning Powder River Basin (PRB) coal with approximate 0.9 to 1.2 lb SO_2/MMBtu content (East Thunder – Jacobs Ranch coal). This is a somewhat higher sulfur content than what the plant normally fires.

At Unit 5, particulate and mercury were measured before the ESP. At Unit 6, SO_2, mercury and particulate were measured before the ESP and particulate, mercury, SO_2 after the ESP. At the combined stack, particulate, mercury, metals, acid gases and SO_3 were measured. Coal was sampled during baseline testing and a five gallon ash sample was secured for comparison to mixed ash/spent reagent.

Plant PI data records were secured during all tests to document plant loads and performance during testing.

Summary SO2 data are shown in Table 3-2. The values presented are the averages of four runs taken over two days.

Table 3-2 - Baseline Summary SO_2 Data
June 4-5, 2010

Measurement	Unit	Value
SO_2 (Unit 6), Economizer Outlet	Lb/hr	1701.95
SO_2 (Unit 6), Economizer Outlet	Lb/MMBtu	0.980
SO_2 (Unit 6), ESP Outlet	Lb/hr	1652.87
SO_2 (Unit 6), ESP Outlet	Lb /MMBtu	0.958

These results were compared to the #3 Tall Stack (units 5 and 6) CEMs data for confirmation. The average SO2 emission from #3 Tall Stack during these test runs was 3,756 lb/hr or based on the assumption that emissions from Unit 5 equal Unit 6 the emission from Unit 6 would be 1,878 lb/hr or about 12% higher than what was read at the ESP outlet. The difference in the results is likely the result of non-uniformed sampling in the duct due to stratification of the flue gas path. Because of this apparent bias between CEMs readings a decision was made to compare sulfur dioxide removal against the stack CEMs readings.

Particulate matter emissions data are shown in Table 3-3. The values presented are the averages of four runs taken over two days. Data indicate overall ESP efficiency of 98.88 percent. The removal efficiency is used in comparing baseline operation with operation during DSI.

Table 3-3 - Baseline Summary Particulate Matter Data
June 4-5, 2010

Measurement	Unit	Value
ESP Inlet (Unit 5 & 6)	Lb/hr	13,685
Combined Outlet	Lb/hr	152.87
Removal Efficiency	Percent	98.88

Total mercury emissions data are shown in Table 3-4. The values presented are the averages of four runs taken over two days for #3 Tall Stack (units 5 and 6). Data indicate overall removal efficiency of 93 percent (based on coal mercury concentration) using the plant's installed PAC injection system. The removal efficiency is used in comparing baseline operation with operation during DSI.

Table 3-4 - Baseline Summary Mercury (Total) Data
June 4-5, 2010

Measurement	Unit	Value
Coal	Lb/hr	0.0468
Coal	Lb/TBtu	11.22
Stack	Lb/hr	0.0033
Stack	Lb/TBtu	0.97
Removal Efficiency	Percent	93

3.1.2 Trona, Un-milled Upstream of the Air Heater

The purpose of this program segment was to document emissions and plant operating characteristics injecting un-milled (D50 of 39 microns) (not milled on site) Trona upstream of the AH. The Trona size analysis is shown in Section 2.2.

The test occurred on 7 June. Three test runs were performed on the test date. The plant was burning coal from the East Thunder (Jacobs Ranch) mine with an approximate 0.9 – 1.2 lb SO_2/MMBtu content. During the performance of the tests one of the DSI blowers tripped on overheat for about 20 minutes (15:35 – 15:55) which reduced the injection of Trona by one/half for that period of time.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

In accordance with the test program no measurements were made on Unit 5. On Unit 6, SO_2 and mercury were measured at the economizer outlet "before injection". Particulate matter (TM5) was measured before the ESP and fine particulate (PM_{10} and $PM_{2.5}$), mercury and SO_2 after the ESP. Coal was sampled during testing.

Summary SO_2 data are shown in Table 3-5. Un-milled Trona was injected from 8:45 to 18:55 at varying rates (~3,000 - >13,000 lb/hr). The Trona injection information was compared to the Stack CEMs data to discern a trend. The Unit 6 SO_2 concentration before DSI was estimated based on the SO_2 concentration in the stack before and after DSI with one half of the SO_2 assumed to come from Unit 6. The results were graphed and are shown in Figure 3-1.

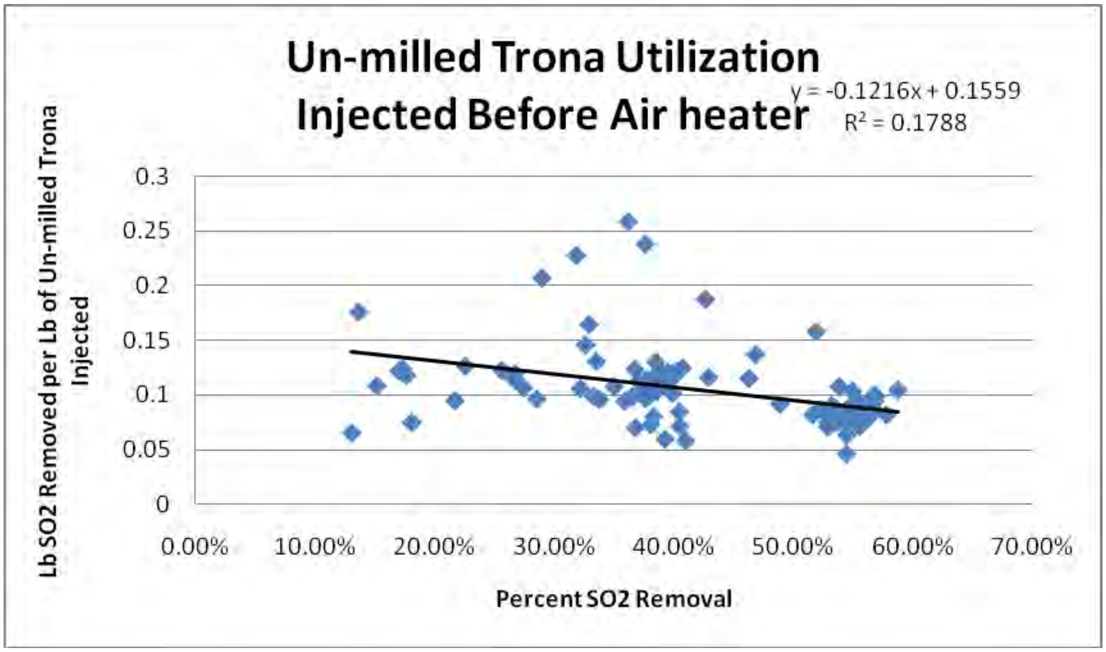

Figure 3-1 – Unmilled Trona Injection Utilization

The results indicate an overall removal efficiency range of 13 – 59% percent and with an efficiency ratio of 0.093 lb SO_2 removed per lb of sorbent injected at 50% SO2 removal.

Table 3-5 - Summary SO_2 Data, Un-milled Trona Injection Upstream of Air Heater June 7, 2010		
Measurement	**Unit**	**Value**
Average SO_2 Units 5 and 6 Before DS Injection during test	Lb/hr	3786
Average SO_2 (Unit 6), before DSI	Lb/hr	1893
Maximum Removal Efficiency Seen	Percent	59
Lb SO_2 Removed/Lb Sorbent at 50% removal	Ratio	0.093

Summary particulate matter emissions data are shown in Table 3-6. The values presented are the averages of three one-hour runs. Data indicate overall ESP efficiency of 99.44 percent, somewhat better than the baseline efficiency.

Table 3-6 - Summary Particulate Matter Data, Un-milled Trona Injection Upstream of Air Heater June 7, 2010		
Measurement	**Unit**	**Value**
ESP Inlet (Unit 6)	Lb/hr	15,062
ESP Outlet	Lb/hr	84.70
Removal Efficiency	Percent	99.44

Total mercury emissions data are shown in Table 3-7. The values presented are the averages of three runs. Calculations, discussed in Attachment 1, indicate overall removal efficiency of 87.7 percent (based on coal mercury concentration). This removal efficiency is not necessarily comparable to the baseline since this is based on Unit 6 only and a comparison requires the assumption that unit 6 equals Unit 5 in emissions.

Table 3-7 - Summary Mercury (Total) Data, Un-milled Trona Injection Upstream of Air Heater June 7, 2010		
Measurement	**Unit**	**Value**
Coal	Lb/hr	0.0223
Coal	Lb/TBtu	9.4
ESP Outlet Unit 6	Lb/hr	0.00273
ESP Outlet Unit 6	Lb/TBtu	
Removal Efficiency	Percent	87.7

3.1.3 Trona, Milled Upstream of the Air heater

The purpose of this program segment was to document emissions and plant operating characteristics injecting milled (D50 of 26 microns) (milled on site) Trona upstream of the AH. Laboratory size analysis for the milled Trona can be found in Attachment 5.

The test occurred on 8 June. milled Trona was injected from 9:10 to 16:40 at an average uniform rate of 8600 lb/hr+/-. The plant was burning coal from the East Thunder (Jacobs Ranch) mine with an approximate 0.9 – 1.2 lb SO_2/MMBtu content.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

In accordance with the test program no measurements were taken on Unit 5. On Unit 6, SO_2 and mercury were measured at the economizer outlet "before injection". Particulate matter (TM5) was measured before the ESP and fine particulate (PM_{10} and $PM_{2.5}$), mercury and SO_2 after the ESP. Coal was sampled during testing.

Summary SO_2 data are shown in Table 3-8. The Trona injection information was compared to the Stack CEMs data. The Unit 6 SO_2 concentration before DSI was estimated based on the SO_2 concentration in the stack before and after DSI with one half of the SO_2 assumed to come from Unit 6. The values presented are the average of the injection throughout the day. The values indicate an overall removal efficiency of 52.6 percent and with an efficiency ratio of 0.10 lb SO_2 removed per lb of sorbent injected. The ratio shows an improvement in removal efficiency over un-milled Trona.

Table 3-8 - Summary SO_2 Data, Milled Trona Injection Upstream of Air Heater June 8, 2010

Measurement	Unit	Value
Average SO_2 Units 5 and 6 Before DS Injection during test	Lb/hr	3273
Average SO_2 (Unit 6), before DSI	Lb/hr	1637
Removal Efficiency	Percent	52.6
Lb SO_2 Removed/Lb Sorbent	Ratio	0.10

Summary particulate matter emissions data are shown in Table 3-9. The values presented are the averages of three one-hour runs. Data indicate overall ESP efficiency of 98.68 percent, not quite as good as the baseline efficiency or that for un-milled Trona.

Table 3-9 - Summary Particulate Matter Data, Milled Trona Injection Upstream of Air Heater June 8, 2010

Measurement	Unit	Value
ESP Inlet (Unit 6)	Lb/hr	12,774
ESP Outlet	Lb/hr	168.09
Removal Efficiency	Percent	98.68

Total mercury emissions data are shown in Table 3-10. The values presented are the averages of three runs. Calculations, discussed in Attachment 1, indicate overall removal efficiency of 84.1 percent (based on coal mercury concentration). This removal efficiency is not necessarily comparable to the baseline since this is based on Unit 6 only and a comparison requires the assumption that unit 6 equals Unit 5 in emissions..

Table 3-10 - Summary Mercury (Total) Data, Milled Trona Injection Upstream of Air Heater
June 8, 2010

Measurement	Unit	Value
Coal	Lb/hr	0.0387
Coal	Lb/TBtu	16.7
ESP Outlet Unit 6	Lb/hr	0.00615
ESP Outlet Unit 6	Lb/TBtu	3.8
Removal Efficiency	Percent	84.1

3.1.4 Trona, Milled Downstream of the Air Heater

The purpose of this program segment was to document the SO_2 emissions and plant operating characteristics injecting milled (D50 of 26 microns) (milled on site) Trona downstream of the AH.

The test occurred on morning of 9 June. milled Trona was injected from 8:50 to 12:30 at an average injection rate of 14,493 lb/hr once the injection rate was stabilized. The plant was burning coal from the East Thunder (Jacobs Ranch) mine with an approximate 0.9 – 1.2 lb SO_2/MMBtu content.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

In accordance with the test program no measurements were taken on Unit 5. On Unit 6, SO_2 was measured at the economizer outlet “before injection”, and after the ESP. Coal was sampled during testing.

Summary SO_2 data are shown in Table 3-11. The Trona injection information was compared to the Stack CEMs data. The Unit 6 SO_2 concentration before DSI was estimated based on the SO_2 concentration in the stack before and after DSI with one half of the SO_2 assumed to come from Unit 6. The values presented are from the morning run. The values indicate an average removal efficiency of 42.6 percent and with an efficiency ratio of 0.049 lb SO_2 removed per lb of sorbent injected. The ratio shows this scenario, injecting downstream of the AH, to be the least efficient of the Trona test alternatives.

Table 3-11 - Summary SO_2 Data, Milled Trona Injection Downstream of Air Heater
June 9, 2010

Measurement	Unit	Value
Average SO_2 Units 5 and 6 Before DS Injection during test	Lb/hr	3,339
Average SO_2 (Unit 6), before DSI	Lb/hr	1,670
Removal Efficiency	Percent	42.6
Lb SO_2Removed/Lb Sorbent	Ratio	0.049

It was anticipated that this test scenario would be no be better, and probably worse than the injection before the AH due to the lower temperature of the flue gas. Thus no additional parameters were sampled. This was a CEMs only test.

3.1.5 Sodium Bicarbonate Downstream of the Air Heater

The purpose of this program segment was to document the SO_2 emissions and plant operating characteristics injecting SBC downstream of the AH.

The test occurred on afternoon of 9 June. SBC was injected from 14:40 to 16:00 with the feed rate ramping up from about 7000 lb/hr up to 11,750 lb/hr. The plant was burning coal from the East Thunder (Jacobs Ranch) mine with an approximate 0.9 – 1.2 lb SO_2/MMBtu content.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

In accordance with the test program no measurements were taken on Unit 5. On Unit 6, SO_2 was measured at the economizer outlet “before injection”and after the ESP. Coal was sampled during testing.

Summary SO_2 data are shown in Table 3-12. The SBC injection information was compared to the Stack CEMs data. The Unit 6 SO_2 concentration before DSI was estimated based on the SO_2 concentration in the stack before and after DSI with one half of the SO_2 assumed to come from Unit 6. The results indicate an overall removal efficiency of 60 percent and with an efficiency ratio of 0.084 lb SO_2 removed per lb of sorbent injected. The ratio and removal efficiency values were based on average 11,750 lb/hr reagent injection.

Table 3-12 - Summary SO_2 Data, SBC Injection Downstream of Air Heater June 9, 2010

Measurement	Unit	Value
Average SO_2 Units 5 and 6 Before DS Injection during test	Lb/hr	3,288
Average SO_2 (Unit 6), before DSI	Lb/hr	1,644
Removal Efficiency @11,750 lb/hr feed rate	Percent	60
Lb SO_2Removed/Lb Sorbent	Ratio	0.084

3.1.6 Sodium Bicarbonate Upstream of the Air Heater Testing

The purpose of this program segment was to document emissions and plant operating characteristics injecting SBC upstream of the AH.

The test occurred on 10 June. SBC was injected from 8:30 to 16:55 at an average injection rate of 7,380 lb/hr The plant was burning coal with an approximate 0.9 – 1.2 lb SO_2/MMBtu content.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

In accordance with the test program no measurements were taken on Unit 5. On Unit 6, SO_2 and mercury were measured at the economizer outlet "before injection". Particulate matter (TM5) was measured before the ESP and fine particulate (PM_{10} and $PM_{2.5}$), mercury and SO_2 after the ESP. Coal was sampled during testing.

Summary SO_2 data are shown Table 3-13. The SBC injection information was compared to the Stack CEMs data. The Unit 6 SO_2 concentration before DSI was estimated based on the SO_2 concentration in the stack before and after DSI with one half of the SO_2 assumed to come from Unit 6. The results indicate an average removal efficiency of 67.1 percent and with an efficiency ratio of 0.16 lb SO_2 removed per lb of sorbent injected. The ratio shows an improvement in removal efficiency over Trona and SBC injection after the air heater.

Table 3-13 - Summary SO_2 Data, SBC Injection Upstream of Air Heater June 10, 2010

Measurement	Unit	Value
Average SO_2 Units 5 and 6 Before DS Injection during test	Lb/hr	3,474
Average SO_2 (Unit 6), before DSI	Lb/hr	1,737
Removal Efficiency	Percent	67.1
Lb SO_2Removed/Lb Sorbent	Ratio	0.16

Summary particulate matter emissions data are shown Table 3-14. The values presented are the averages of three one-hour runs. Data indicate overall ESP efficiency of 97.80 percent, not quite as good as the baseline efficiency.

Table 3-14 - Summary Particulate Matter Data, SBC Injection Upstream of Air Heater
June 10, 2010

Measurement	Unit	Value
ESP Inlet (Unit 6)	Lb/hr	10,401
ESP Outlet	Lb/hr	228.96
Removal Efficiency	Percent	97.80

Total mercury emissions data are shown Table 3-15. The values presented are the averages of three runs. Data indicate overall removal efficiency of 85.8 percent (based on coal mercury concentration. This removal efficiency is not necessarily comparable to the baseline since this is based on Unit 6 only and a comparison requires the assumption that Unit 6 equals Unit 5 in emissions.

Table 3-15 - Summary Mercury (Total) Data, SBC Injection Upstream of Air Heater
June 10, 2010

Measurement	Unit	Value
Coal	Lb/hr	0.0321
Coal	Lb/TBtu	16.7
ESP Outlet Unit 6	Lb/hr	0.00455
ESP Outlet Unit 6	Lb/TBtu	2.33
Removal Efficiency	Percent	85.8

3.1.7 Sodium Bicarbonate Downstream of the Air Heater Parametric Testing

The purpose of this program segment was to document emissions and plant operating characteristics injecting SBC downstream of the AH. The amount of SBC added was adjusted throughout the day (9:10 - 19:35) to obtain a trend between SO_2 removal and SBC injected. The SBC was added to both Units 5 and 6 from 3500 to about 16,000 lbs/hr (or from 1,750 – about 8,000 lb/hr/unit)

The test occurred on 11 June. The plant was burning coal from the East Thunder (Jacobs Ranch) mine with an approximate 0.9 – 1.2 lb SO_2/MMBtu content. During the performance of the tests Both units 5 and 6 had temporary coal feeder issues that resulted in temporary minor reductions in plant output.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

In accordance with the test program no measurements were taken on Unit 5. On Unit 6, SO_2 was measured at the economizer outlet “before injection”and after the ESP. Coal was sampled during testing.

The SBC injection information was compared to the Stack CEMs data to discern a trend. The Unit 5 and 6 SO_2 amount before DSI was estimated based on the SO_2 concentration in the stack before and after DSI. The results were graphed and are shown in Figure 3-2.

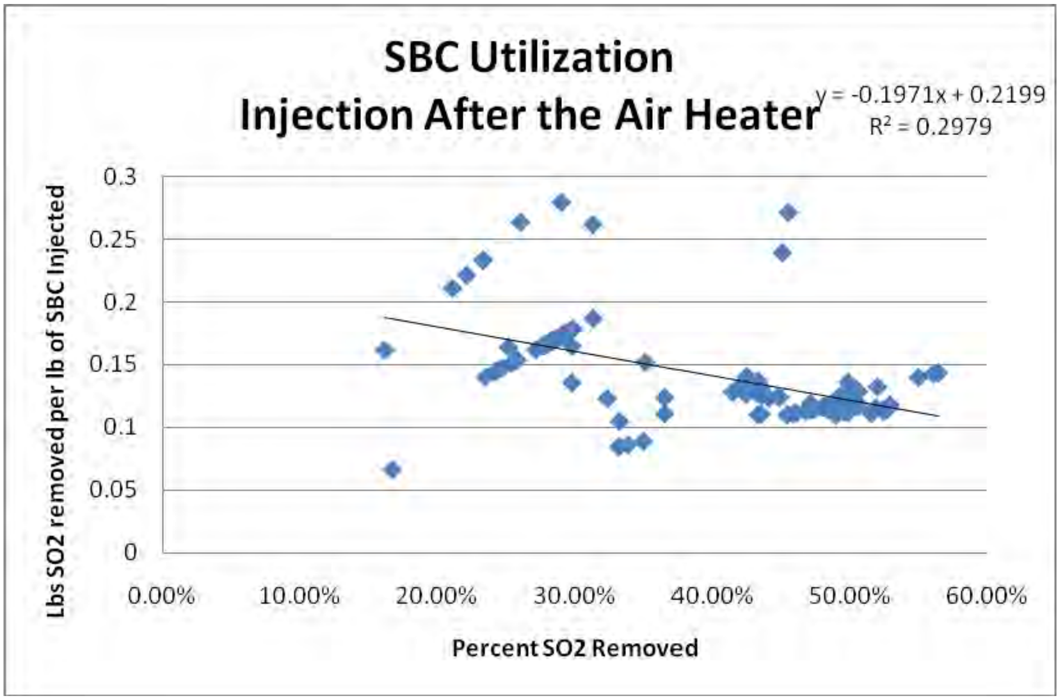

Figure 3-2 – SBC Utilization, Injection After the Air Heater

Summary SO_2 data are shown Table 3-16. The removal efficiency range of 16 - 53 percent was seen and with an efficiency ratio of 0.121 lb SO_2 removed per lb of sorbent injected at 50% SO2 removal.

Table 3-16 - Summary SO_2 Data, SBC Injection Downstream of Air Heater Units 5 and 6, June 11, 2010

Measurement	Unit	Value
Average SO_2 Before DS Injection during test	Lb/hr	1983.3
Maximum Removal Efficiency Seen	Percent	53
Lb SO_2Removed/Lb Sorbent at 50% SO_2 removal	Ratio	0.121

3.1.8 Sodium Bicarbonate Downstream of the Air Heater Units 5 and 6 Steady State Testing

The purpose of this program segment was to document emissions and plant operating characteristics injecting SBC downstream of the AH on a continuous basis.

The test occurred on 14 June. The plant was burning coal from the Belle Ayr mine with an approximate 0.6 lb SO_2/MMBtu content. This is a coal with a lower sulfur content than what the plant was burning during earlier test days. SBC was injected into both Units 5 and 6 from 10:00 – into June 15 at an average injection rate of 9,980 lb/hr after initial ramp up. The operation of the ESPs were impacted by the combination of the Belle Ayr coal and the SBC injection with lower power levels and an initial increase of 4-5% in opacity. This spike stabilized and the opacity trended down as the tests continued.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

CEMs measurements were taken on Unit 5 and Unit 6, at the economizer outlet, before injection. The plant CEMs in #3 Tall Stack was used to measure SO_2 emissions. Coal was sampled during testing.

Summary SO_2 data are shown Table 3-17. The results indicate an overall removal efficiency of 54.7 percent and with an efficiency ratio of 0.112 lb SO_2 removed per lb of sorbent injected.

Table 3-17 - Summary SO_2 Data, SBC Injection Downstream of Air Heater Units 5 and 6, June 14, 2010

Measurement	Unit	Value
Average SO_2 Before DS Injection during test	Lb/hr	2,036
Average SBC injection	Lb/hr	9,980
Removal Efficiency	Percent	54.7
Lb SO_2Removed/Lb Sorbent	Ratio	0.112

3.1.9 Continued Sodium Bicarbonate Downstream of the Air Heater Units 5 and 6 Steady State Testing

The purpose of this program segment was to to continue to document emissions and plant operating characteristics injecting SBC downstream of the AH on a continuous basis.

The test occurred on 15 June and into 16 June. The plant was burning coal from the Belle Ayr mine with approximate 0.6 lb SO_2/MMBtu content. This is a coal with a lower sulfur content than was burned in the first two weeks of tests.

SBC was injected into Units 5 and 6 for all of June 15 and into June 16. Full load operation of Units 5 and 6 began about 6:25. The average SBC injection rate was about 9,960 lb/hr for both units during full load operation. This testing was curtailed when Unit 5 developed a tube leak resulting in the unit being taken out of service around 5:00.

Attachment 3 shows the arrangement of the NolTec injection equipment and lances into the plant ductwork.

On Unit 5 and Unit 6, CEMs measurements and mercury were sampled at the economizer outlet. On both units, particulate matter (TM5) was used at the ESP inlet. Mercury, metals, acid gases, SO_3 and particulate were measured at the common #3 Tall Stack.

Summary SO_2 data are shown Table 3-18. The values indicate an overall removal efficiency of 54.7 percent and with an efficiency ratio of 0.113 lb SO_2 removed per lb of sorbent injected. This feed rate and removal efficiency continued into June 16 until Unit 5 was brought down at about 5 am. SBC injection continued at a reduced rate with just Unit 6 in operation with an average feed rate for Unit 6 of 4,950 lb/hr, with 52.9% SO_2 removal efficiency and a 0.109 Lb SO_2Removed/Lb Sorbent utilization.

Table 3-18 - Summary SO_2 Data, SBC Injection Downstream of Air Heater Units 5 and 6, June 15, 2010

Measurement	Unit	Value
Average SO_2 Units 5 and 6 Before DS Injection during test	Lb/hr	1055.7
Average SBC injection Rate	Lb/hr	9,960
Removal Efficiency	Percent	54.7
Lb SO_2Removed/Lb Sorbent	Ratio	0.113

Summary particulate matter emissions data are shown Table 3-19. The values presented are the averages of three one-hour runs. Data indicate overall ESP efficiency of 99.02 percent, better than baseline efficiency. Although the efficiency is somewhat better than the baseline, the real problem is the total particulate is 75 lb/hr more than measured with the baseline testing.

Table 3-19 - Summary Particulate Matter Data, SBC Injection Downstream of Air Heater June 15, 2010

Measurement	Unit	Value
ESP Inlet (Unit 5)	Lb/hr	10,367
ESP Inlet (Unit 6)	Lb/hr	12,822
Stack	Lb/hr	227.70
Removal Efficiency	Percent	99.02

Total mercury emissions data are shown Table 3-20. The values presented are the averages of three runs. Data indicate overall removal efficiency of 93.7 percent (based on coal mercury concentration), which is consistent with the baseline efficiency. The removal efficiency represents the combined removal of the DSI and PAC injection system.

Table 3-20 - Summary Mercury (Total) Data, SBC Injection Downstream of Air Heater
June 15, 2010

Measurement	Unit	Value
Coal	Lb/hr	0.0186
Coal	Lb/TBtu	8.34
Stack	Lb/hr	0.00235
Stack	Lb/TBtu	0.65
Removal Efficiency	Percent	93.7

3.1.10 Comparison of Certain Metals Emissions, During Baseline and SBC Injection

Ten metals were measured in the stack during the baseline sampling and again when injecting SBC on the final day of testing. Different coals were burned between the two test days. Table 2-3 shows the analyses of the two coals during the test period.. From a visual review of the data, it is not evident that SBC had an impact on metals emissions, either positive or negative. There is some indication that SBC may have decreased the amount of nickel or selenium in the emissions. .

3.1.11 Comparison of Acid Gas Emissions, During Baseline and SBC Injection

Hydrochloric acid and hydrofluoric acid gases were measured in the stack during baseline sampling and when injecting SBC on the final day of testing. The average emission rates are shown in Table 3-21. Different coals were burned between the two test days. Table 2-3 shows that the Jacobs Ranch coal had on average slightly greater concentrations of chlorine than Belle Ayr coal, however, on the days tested the chlorine concentrations were similar. Fluorine concentrations were not sampled.

Assuming the Belle Ayr coal had similar concentrations of chlorine and the same or higher concentrations of fluorine, a minimum of about 80% removal of the acid gases when comparing the baseline test results with the SBC injection results.

Table 3-21 - Comparison of Acid Gas Emissions

Date	Test	Average HCl Lb/hr	Average HF Lb/hr
4-5-Jun (1)	Baseline	2.335	6.21
15-Jun(2)	SBC after the air heater	<0.53	1.23
	Removal (3)	>77.3%	80.2%

Notes:

1. Burned East thunder (Jacobs Ranch) PRB Coal
2. Burned Belle Ayr PRB Coal
3. Based on the assumption that the two coals have the same concentrations of chlorine and fluorine

3.1.12 DSI Impacts on NOx Emissions

The NOx emissions between the baseline sample dates and the DSI dates were reviewed to see if there was a discernable impact of DSI on NOx emissions. The data is included in Attachment 1. Little to no reduction in NOx emissions was seen with the injection of dry sorbent.

3.2 Comparison of Dry Sorbent Utilization

3.2.1 Dry Sorbent Utilization versus SO_2 Removal

A comparison of the amount of SO_2 removed against the amount and type of DSI was made to delineate the utilization efficiency of each of the dry sorbents used. Since the SO_2 concentration in the flue gas varied with time over the test runs a comparison of the dry sorbent utilized needs to be compared on an amount of SO_2 removed to amount of dry sorbent used. It should be noted that the SBC utilized during the test program was pre-milled. However, when it arrived portions of the SBC had clumped together resulting in unloading problems. This clumping may be indicative of a general degradation in the particle size (increase in particle size from the milled state) that could impact the SBC performance.

Table 3-22 provides a tabular comparison of the dry sorbent injected versus SO_2 removed.

The test results for SBC injection were graphed as provided in Figure 3-3 below.

Some general conclusions can be made from reviewing the comparisons provided in Table 3-22 and in Figure 3-3:

- Greater than 50% SO_2 removal was obtained with un-milled Trona, and milled Trona before the air heater and with SBC before or after the air heater
- 50% removal was not seen with milled Trona after the air heater
- SBC had a better utilization efficiency than Trona whether milled or un-milled with a 0.158 lbs SO2 removed per lb of dry sorbent versus 0.100 lbs SO2 removed per lb of dry sorbent for milled Trona when injection was before the air heaters
- Milled Trona was more efficient than un-milled Trona in SO_2 removal (ratio averages 0.100 vs. 0.093, lbs SO2 removed per lb of dry sorbent respectively) when injected before the air heater
- The injection location (whether before or after the air heater) impacts the efficiency of Trona and SBC utilization, with injection before the air heater having a significantly greater utilization efficiency
- The trend line for SBC utilization shows that the SBC utilization efficiency decreases with increased % SO_2 removal
- When using SBC for 50% SO_2 removal, an utilization rate of about 0.12 lbs SO_2 removed per lb of SBC is needed with injection after the air heater and a significantly greater utilization(>0.158 lbs SO2 removed per lb of dry sorbent) if injection is before the air heater
- Dry sorbent injection will reduce acid gases; 80+% removal was seen in these tests

Table 3-22 - SO_2 Removed Versus DSI Utilization (1)						
Date	**Injection Duration W/ Plant at Full Load**	**DSI**	**Injection Location**	**Average Injection Rate (LB/Hr)**	**SO_2 Removal Efficiency**	**Lbs SO_2 Removed per Lb DSI**
7-Jun	8:45 – 18:35	Un milled Trona	Before air heater – Unit 6	3,000 - >13,000	13 – 59	0.093 @ 50% SO_2 removal
8-Jun	9:10 – 16:40	Milled Trona	Before air heater – Unit 6	8,600 +/-	52.6	0.10
9-Jun	8:50 – 12:30	Milled Trona	After air heater – Unit 6	14,493	42.6	0.049
9-Jun	14:40 – 16:00	Pre-milled SBC	After air heater – Unit 6	11,750	60	0.84
10-Jun	8:30 – 16:55	Pre-milled SBC	Before air heater – Unit 6	7,380	67.1	0.158
11-Jun	9:10 – 19:35	Pre-milled SBC	After air heater - Units 5 and 6	3,500 – 16,000	16 – 53	0.121 @ 50% SO_2 removal
14-Jun	10:00 – 24:00	Pre-milled SBC	After air heater - Units 5 and 6	9,980	54.7	0.112
15 - 16-Jun	6:25 - 4:55 (6-16)	Pre-milled SBC	After air heater - Units 5 and 6	9,960	54.7	0.113
16-Jun	5:35 – 6:30	Pre-milled SBC	After air heater - Unit 6	4,950	52.9	0.109

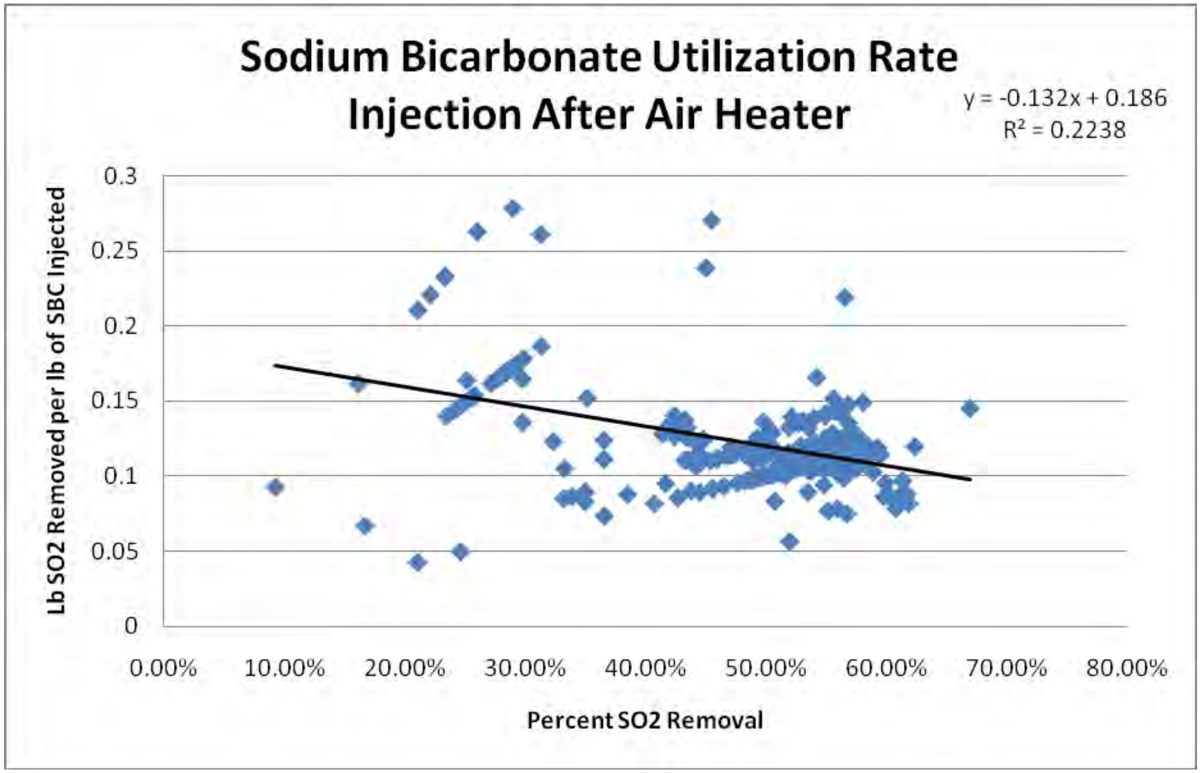

Figure 3-3 – Efficiency of SO_2 Removal Using SBC After The Air heater

3.2.2 Impacts of Dry Sorbent Utilization on Particulate Emissions

A comparison of the Unit 5 and 6 stack total particulate emissions during baseline testing (June 4-5, 2010) versus total particulate emissions during steady state SBC injection (June 15, 2010) are shown in Table 3-23. This comparison shows an increase in total particulates of 74.83 lbs/hr with the injection of dry sorbent. This equates to increase in total particulates of 295 tons/yr from Units 5 and 6 assuming a 90% capacity factor.

Table 3-23 - Comparison of Total Particulate Emissions

Test Date	DSI	Injection Location	Total Particulate Inlet to ESP (lb/hr)		#3 Tall Stack Total Particulate Emissions (lb/hr)	ESP Collection Efficiency (Percent)	Outlet Particulate Emissions (lb/MMBtu)
6/4-5/2010 (1)	Baseline	NA	Unit 5	6,822			
			Unit 6	6,863			
			Total	13,685	152.87	98.88%	0.046
6/15/2010 (2)	Steady-State SBC @ 10,159 lb/hr avg)	Down Stream of Air Heater	Unit 5	10,294			
			Unit 6	12,822			
			Total	23,116	227.70	99.01%	0.060
Deltas				9,431	74.83	0.13%	0.014

Notes:

1. East Thunder PRB Coal burned
2. Belle Ayr PRB coal with approximately 15% lower ash than the East Thunder average burned on 6/4-5/2010

The type of dry sorbent utilized also affected the type of particulate emissions from the existing ESPs. Table 3-24 provides a comparison of the particulate emissions by size of particulate versus the June 4-5 baseline test data. In all cases the Unit was burning Jacobs Ranch coal. Table 3-24 also provides the average DSI rate.

Table 3-24 - Review of Average Particulate Emissions versus DSI on Unit 6

Test Date	DSI	Average DSI Rate (lb/Hr)	Injection Location	Total Particulate Emissions (lb/hr)	PM>10 (lb/hr)	PM<10 (lb/hr)	PM<2.5 (lb/hr)
6/5/10	Base Test	NA	NA	81.32	13.48	67.84	17
6/7/10	Un-milled Trona	8,502	Upstream of Air Heater	84.7	5.14	79.56	13.63
6/8/10	Milled Trona	8,696	Upstream of air heater	163.99	9.14	154.85	31.75
6/10/10	Pre-milled SBC	7,150	Down Stream of Air Heater	228.96	8.61	220.35	20.69

Reviewing the results provided in Tables 3-23 and 24 show that the addition of DSI to the flue gas stream increases the total particulates leaving the ESP with the majority of increase being PM<10 microns. Injecting milled dry sorbent has the most impact on the increase of fine particulates with the pre-milled SBC having a greater impact than the milled Trona, though the results from the testing on June 10 are suspect since they are greater than what was measured on June 15 for the combined Unit 5 and 6 emissions with SBC injection. The least impact on particulate emissions was the injection of un-milled Trona which had the largest particle size of all of the test runs. It should be noted that with the addition of dry sorbent no impacts on the operation of the ESP or opacity were observed when firing Jacobs Ranch coal. The Opacity and ESP performance (i.e. spark rates, secondary current, etc.) did change with SBC injection when firing the Belle Ayr coal with an increase in opacity of several percent. This increase did not cause the plant any issues with meeting theplant’s opacity limits.

3.2.3 Impacts of DSI Utilization on Mercury Emissions

The removal efficiency of mercury during injection of DSI was reviewed and is included in Attachment 1. The results indicate a baseline removal efficiency of 93% with the injection of a minimum of 5 lbs activated carbon per million acf. During DSI the mercury removal varied from 84.1 – 93.7% with 93.7% removal occurring during SBC injection to both units. This removal efficiency is based on the concentration of mercury in the coal burned. Throughout the DSI test the activated carbon injection rate was unchanged. Based on the low values of mercury analyzed and the 10% variability of removal during injection, it is difficult to state whether DSI had any real impact on mercury removal.

3.3 Byproduct Characterization

The characterization of the DSI by-products is included in Attachment 2.

3.3.1 Current Byproduct Operations

On 15 June, a Shaw and EEI representative went to the ash handling area approximately ½ mile north of the plant. The current operation is contracted.

An interview with the operators indicated ash production over a 60 hour operating weekend was approximately 1500 tons for the six units. The ash handling area has storage for 1800 tons in three silos. This calculates to approximately 4.16 tph per unit of ash produced (PRB coal).

Ash is pneumatically blown into the silos. Ash is dropped into trucks using a dustless unloader, supplied by DustMaster, Turbin Mixer XL Series II (Pewaukee, WI). The operators currently add approximately 10.5 to 10.7 % water (lb of water/lb of water plus ash). Mixed byproduct loading rates were 77 – 81 tons/hour. For the DSI testing, EEI's contracted ash plant operator processed the ash/sorbent mix in the DustMaster. The waste material was shipped to a municipal landfill approximately an hour distant. At this time, EEI is in the process of completing the development of a dedicated nearby landfill. Plans would be to add the new mixed byproduct to the new landfill.

EEI (17 June) reported an increase in LOI with DSI. Ash materials were generally reported at a LOI near 2.0% when injecting activated carbon, but LOI increased to up to 8.1% with DSI. The mixed byproduct also had a slightly higher moisture in the silo.

During the test program, the operators reported that when wet, the mixed byproduct generated considerable heat. This finding is consistent with the Shaw E&I materials lab results, discussed below.

On the day of the interview, 25 gallons of mixed byproduct were secured in plastic shipping containers. The mixed byproduct was sent to the Shaw E&I materials laboratory in Knoxville TN for characterization testing.

3.3.2 Byproduct Characterization Testing

At the Shaw E&I materials laboratory, a number of tests and characterization studies were performed. The work was performed to describe for operators the expected characteristics of mixed byproduct.

Among the byproduct characterization tests performed were:

- Bulk density, percent solid content, pH
- Dry sieve particle size analysis to 75 micron
- Atterberg limits
- Screening Moisture Addition

- Dissolution in water
- Total and toxic characteristic leaching procedure (TCLP) Analyzed for Expanded EPA target analyte list (TAL)
- Harvard Miniature Proctor Test
- Standard Proctor Test
- Temperature rise with water addition
- 7-Day Unconfined Compressive Strength (UCS)
- Dissolution of 7-day cured material at approximately optimum water content, 2 point ANSI 16.1
- Permeability of 7-day cured material at approximately optimum water content with ICP analysis of effluent
- Direct Shear, Normal/Residual
- California Bearing Ratio (CBR)
- Consolidation, One-Dimensional
- Triaxial Shear, Unconsolidated, Undrained

3.3.3 Highlights of Laboratory Results

When comparing of SBC byproduct vs. baseline ash, the reader should remember that the plant was burning different coals when the samples were collected. The physical characteristics of the two products are likely more comparable, than metals content or leachate.

Densities - Bulk density testing indicated that the densities of the two byproducts are similar. The bulk densities of the dry, as received baseline fly ash and the SBC byproduct were 69.0 and 61.9 lb/ft^3, respectively. When water was added to the byproduct samples, the densities increased to a maximum of 126 lb/ft^3 with 15 percent water addition for the baseline fly ash. Similarly, the SBC byproduct density generally increased to a maximum of 120 lb/ft^3 with water addition of up to about 25 percent. During screening water addition tests, the SBC byproduct freely released water after reaching 25% water addition. At 26 % water addition the SBC ash became a flowable paste. The maximum density measured in the Harvard Miniature proctor tests was at about 25% water addition; however, liquid was released when pressure was applied at the optimum moisture addition rate.

Sieve Analysis. Analysis of the dry sieve results shows that the SBC byproduct is mostly fine sand and silt size particles. Analysis of the Atterberg results shows that ash behaves like slightly cohesive silt. The fines become cohesive and liquefy at 22 and 26 percent geotechnical moisture content (w/d), respectively.

Characteristics with Water Addition - From initial SBC byproduct screening water addition tests, when all the water was added at once and the wetted byproduct is compacted, it will rapidly adsorb water into the compacted samples beyond its ability to hold the liquid when pressure is applied. With many of the formulations, when the standing water was removed and the material allowed to cure for about 48 hrs, a friable crust on top of the compacted material was formed (water was only removed for testing, then added back to the sample; therefore any free water remained on the sample for the whole testing period).

At lower water addition rates, the SBC byproduct set and self hardened at a slightly slower rate than the baseline ash. The rate of SBC byproduct setting, self hardening and heat release can somewhat be controlled by the amount of water added to it. The baseline ash hardened to > 4.5 tsf resistance at all moisture addition rates within 30 minutes. The SBC byproduct hardened to > 4.5 tsf with ≥ 11 percent moisture addition rates within 30 minutes. At < 9 % water addition rates to the SBC ash, the product is harder to mix (water into the ash).

As a compromise between rate of set, rate of heat released, ease of mixing, compacted wet density, liquid release and liquefaction, water additions were separated into two steps. First 9% water was added to simulate dust control processes at the site. In this step about 60% of the heat was released. The remaining water was added and the wetted ash compacted which simulates water addition and compaction at the landfill. At a total water addition rate of 19, 21 and 23 percent, the densities were slightly lower than at optimum moisture content of 25%; however, at these lower water addition rates the compacted samples did not release liquid or liquefy. The UCS, modified ANS/ANSI 16.1, leaching tests and permeability tests used this two step water addition and compaction process. In addition, at 21 and 23 percent water additions, the amount of water that would adsorb into the compacted SBC byproduct was limited when compared to lower water addition rates.

At the three selected total water additions, the SBC byproduct, after compaction, self hardened to UCS values in excess of 98 psi at 7 days. This is well in excess of the commonly recommended UCS values for landfills of 10, 25 or 50 psi. The duplicate UCS results vary more than is normally seen for soils that are treated with pozzolonic materials or Portland cement. Submersion in water for 7 days caused about a 10% loss in UCS strength for the 21% water addition sample. This loss may be within the accuracy of the tests for SBC byproduct.

Even though the monolithic material maintained its physical shape and UCS values, about 16% of its mass dissolved during the 7 day immersion study. The pH remained high (>12.5) during the immersion test. Thus, the soluble components of the byproduct material may dissolve if water is allowed to set on top of it and percolate through the treated material.

PH - The high pH of SBC byproduct is likely the result of CaO, Ca(OH)2, CaCO3, NaOH, Na2CO3 and NaHCO3 contents. The leachate pH values exceed typical site discharge criterion of about 8.5. The pH of the baseline sample is similarly high and, therefore, any leachate from the landfill may need to be neutralized or flow diluted with other precipitation to lower the pH to meet discharge requirements. It should be noted that leachate at the landfill will pumped to two above-ground steel tanks. The liquid will then be transported off-site for treatment and disposal.

Temperature - Samples at varying water additions were subjected to monitoring for heat increase. With total water added between 9 and 23 % (weight basis), temperature rise between 47 and 60 °F occurred. Time elapsed to arrive at a maximum temperature was 29 to 88 minutes. Byproduct heat generation upon addition of water is consistent with observations of EEI during the test program.

Stabilization Testing - SBC byproduct was mixed with other materials to test for enhanced stabilization characteristics. The byproduct was mixed with Portland Cement, Blast Furnace Slag and Terrabond. Results indicate a greater UCS value where Portland Cement is added in as little as 5% by weight.

Metals Analysis - Total metal analyses show that most metals concentrations in the SBC byproduct range from 65 to 78% of that of the baseline ash. Notable exceptions include sodium and sulfur which are, understandably at much higher concentrations in the SBC byproduct. Mercury and selenium are somewhat higher in the SBC byproduct. Barium was an order of magnitude higher in the baseline ash. As mentioned above, the coals used in baseline tests and used in SBC tests were different and their metals content are not directly comparable.

Leachate Testing – Leachate testing was run on both the base line ash and the ash/SBC byproduct. The results of this testing show:

- That both the baseline and SBC ashes do not exceed the US EPA Toxicity Characteristics criteria for RCRA hazardous waste.
- It is expected that the landfill leachate will need pH neutralization before discharge. The leachate, based on the lab results, should also have high TDS.
- Even though the landfill water will not be discharged to groundwater, the leachate values were analyzed against the IL groundwater standard as a point of reference. Several metals and an anion sulfate (based on the sulfur results) exceed the state groundwater standards.

Permeability Testing - Permeability testing was performed on the water treated and compacted SBC ash and the solidified and stabilized SBC ash formulations. After greater than 30 days, permeability results could not be obtained due to gas generation within the permeable chamber. GC analysis indicates the gas is hydrogen gas when the SBC ash is contacted with water for sufficient time.

Following permeability testing sample specimens were tested for changes in UCS and dimensional degradation. These tests indicated no reduction in strength or degradation due to short term water permeation into the sample matrices.

Effluent testing of the permeation liquids indicated elevated pH of permeate waters, containing high levels of sodium and sulfur as well as lower levels of various metals.

3.4 Impacts on Operation

3.4.1 Utilization of DSI at Joppa

From this set of tests the decision of whether to use Trona (milled on-site) or SBC (milled on-site) would become one of economics if injection before the air heater is not considered an issue. One point for consideration is if SBC addition after the air heater is selected; what is the temperature of the flue gas during partial load operation. If the air heater gas outlet temperature drops to below the recommended Solvay low temperature for SBC utilization of 275 ^{o}F the utilization efficiency will drop. The PI data provided as part of this study showed the lowest temperature measured over the eight days was 284.7 ^{o}F in Unit 5 which occurred in the morning during the ramp up from partial load to full load. All of the SBC runs feeding SBC after the air heater were at temperatures in the 330 ^{o}F range. Partial loads at night or for an extended period of time with a resultant low temperature out of the air heaters may adversely impact the utilization rate of SBC especially when that temperature approaches 275 ^{o}F and given the spread of temperatures across air heater outlet due to rotary design.

As seen in the results, the addition of DSI adversely impacts the amount of particulates that leaves the ESP. This increase in particulates would impact the plant’s air permit as discussed below. The least impact on particulate emissions resulted from the use of un-milled Trona though there still was an increase in PM10. Significant modifications to the plant’s ESPs would be required to limit the additional particulate emissions.

3.4.2 Air Permit Considerations

The Joppa Generating Station operates of six (6) coal-fired boilers for electric generation and is a “major” source under the Clean Air Act (CAA) Title V operating permit program. The boilers also have the ability to burn fuel oil or natural gas. As discussed above, the injection of dry sorbent would increase particulate emissions. The Station would like to retain the existing electrostatic precipitators (ESP) for particulate control. The Station would also like to avoid applicability of Prevention of Significant Deterioration (PSD) due to exceeding the “significant net emission” threshold for particulate emissions.

Shaw conducted a preliminary PSD analysis for this project. This is not intended as a complete and final PSD analysis for the project due to several assumptions that had to be made to complete the analysis.

An existing major stationary source (i.e. the facility) is applicable to PSD if it undergoes a major modification. Major modifications are physical or operational changes at an existing major stationary source that causes a significant “net emissions increase”. Table 3-25 below lists the signification net emissions increase thresholds for particulate emissions. The PSD analysis is based on total particulate emissions which is the sum of filterable (Method 5) plus condensable (Method 202) emissions.

Table 3-25 - Particulate Significant Net Emissions Increase

Pollutant	Significant Net Emissions Increase (ton/yr)
PM	25
PM10	15
PM2.5	10

A netting analysis is done to determine if any pollutants trigger the significant net emissions increase. The netting analysis includes all changes to the pollutant in the facility. For this preliminary analysis, Shaw considered the changes to the boilers emissions based on the DSI and material handling of the DSI only. For a full PSD analysis, all changes in pollutant emissions across the facility are included in the netting analysis.

Shaw conducted a netting analysis to determine the various options that would not trigger PSD for the Joppa facility due to DSI. The netting analysis included comparing the baseline emission prior to the modification to the projected actual emissions after the modification. The baseline emission was determined as the representative actual emission over a 5 year look back period. Projected actual emissions after the modification were based on the projected comparable particulates with SBC injection and associated material handling operations. The SBC injection data generated in these tests were used assuming a 50% SO_2 removal.

Shaw conducted several different PSD analyses based on different baselines and emission factor sources. These analyses were done on Unit 5 and Unit 6 only since those are the only boilers that were tested during the SBC injection. In a full scale PSD analysis, all other units expected to use SBC injection will need to be included in the calculations. These analyses assume the plant will operate in the future as it has operated in the past. Not reviewed are alternate scenarios such as reduced load operation or replacement of a portion of the coal with alternate fuels such as natural gas.

The analyses and results are discussed in the following sections.

Scenario 1: PSD Analysis Using the Most Recent Baseline Period (Q3-Q4 2009 and Q1-Q2 2010)

For this analysis, Shaw considered the baseline period to be equal to the last four quarters of operation (Q3-Q4 of 2009 and Q1-Q2 of 2010). The baseline emissions from Q3-Q4 2009 were calculated based on the Unit 5 and Unit 6 emission factors and hours of operation reported in the CY2009 air emission inventory. The baseline emissions from Q1-Q2 2010 were calculated based on the average emission factor measured during the June 4-5, 2010 test (Run 1 was omitted as an outlier). The total particulate emissions were measured at the stack during the baseline test for Unit 5 & 6. This emission rate (152.87 lb/hr) was divided in half to obtain the individual emission factor for Unit 5 and Unit 6, considering the fact that the two units were similar in capacity. PM10 and PM2.5 were not measured at the stack, but were measured at the Unit 6 ESP outlet. Shaw assumed that the speciation of the filterable particulate fraction for Unit 5 was the same as that measured for Unit 6. The June 4-5, 2010 baseline test (i.e. without injection of SBC or Trona) on Unit 6 ESP outlet showed that 83% of filterable particulate was PM10 and 21% was PM2.5, which was considered in the analysis.

The future projected actual emissions included the emissions from material handling of the DSI and the increase in particulate emissions from the boilers emissions. For the material handling, Shaw assumed that DSI would be pneumatically conveyed within the facility and one storage silo would be required for Unit 5 & 6 stack. The storage silo was assumed to be controlled by a baghouse with 99.7% efficiency. No other material handling emissions were considered. It may be noted that in a full PSD analysis, the increase in emissions resulting from the increase in fly ash and spent DSI handling would have to be included.

The projected future emissions of Unit 5 and Unit 6 boilers were calculated based on the emissions measured from the June 15, 2010 SBC injection test. It was assumed that the boilers would operate the same amount of hours as was reported during the baseline period (i.e. no increase in capacity factors over baseline). The total particulate emissions were measured at the stack during the SBC test for Unit 5 & 6. This emission rate (228 lb/hr, 155.1 lb/hr filterable and 72.7 lb/hr condensable) was divided in half to obtain the individual emission factor for Unit 5 and Unit 6 for reasons mentioned earlier. PM10 and PM2.5 were not measured at the stack, but were measured at the Unit 6 ESP outlet. The results of the test conducted on June 10, 2010 (SBC injection) at the ESP outlet did not seem to be consistent with other results. PM10 and PM2.5 were also measured at the Unit 6 ESP outlet for a Milled Trona injection test. Shaw assumed that the particulate speciation for the Milled Trona would be similar to the SBC. Shaw also assumed that the particulate speciation for Unit 5 was the same as that measured for Unit 6. The June 8, 2010 Milled Trona test on Unit 6 ESP outlet showed that 94% of filterable particulate was PM10 and 19% was PM2.5, which was considered in the analysis.

The results of the Scenario 1 analysis are shown in Table 3-26.

Table 3-26 - Scenario 1 PSD Analysis Results						
	Pollutant	**Units**	**Value**	**Increase from Baseline**	**Federal Threshold for Significant Emissions Increase (1)**	**Exceeds Significant Emissions Increase Thresholds? Y/N**
Baseline Actual Emissions Unit 5 and 6 Only (ton/yr)	PM	ton/yr	574.72	-	-	-
	PM10	ton/yr	293.34	-	-	-
	PM2.5	ton/yr	105.77	-	-	-
Future Projected Emissions Unit 5 and 6 Only (ton/yr)	PM	ton/yr	934.37	359.65	25	Y
	PM10	ton/yr	600.17	306.83	15	Y
	PM2.5	ton/yr	123.06	17.29	10	Y

Notes:

(1) This is the total plant threshold limit. If all six boilers are retrofitted then this limit would be reduced to a third of what is shown for the emissions from Units 5 and 6.

The analysis showed that the facility could trigger PSD due to increase in particulate emissions over the significant emission rates threshold. The main reason for the increase was the higher emission from the ESP as a consequence of SBC loading. The material handling emissions were not significant in the calculations when compared to the increase in emissions from the boilers.

One option for Joppa to avoid triggering PSD would be to improve the efficiency of the existing ESP such that there will be no net significant increase in particulate emissions. There is no data available to speciate the inlet particulate, so Shaw assumed that the inlet particulate speciation was equal to the outlet particulate speciation. Considering the assumed future hours of operation, inlet particulate loading (from the June 15, 2010 Unit 5 and 6 ESP inlet test), and the assumed particulate speciation, Shaw calculated that the control efficiency would have to be 99.515% (based on PM10). The PM10 emissions would then be:

Unit 5: 10,294 lb/hr * (1-0.99515) * 8381 hr/yr / 2000 lb/ton * 94% (ratio filterable PM to PM10) * 155.1/228= 133.78 ton/yr
Unit 6: 12,822 lb/hr * (1-0.99515) * 8008 hr/yr / 2000 lb/ton * 94% (ratio filterable PM to PM10) * 155.1/228 = 159.22 ton/yr

Total emissions will be approximately 293.0 tpy from the two boilers and the net emissions increase from the boilers would be close to zero (accounting for rounding).

Scenario 2: PSD Analysis Assuming CY2010 as the Baseline Period

For this analysis, Shaw considered the baseline period to be equal to calendar year 2010 as if the PSD application was being submitted sometime in 2011. Shaw obtained the operating data from Joppa for the first two quarters of 2010. Shaw assumed that the total hours of operation for CY2010 would be equal to the total hours of operation for the baseline period of Q3-Q4 2009 through Q1-Q2 2010. The baseline emissions were calculated based on the average emission factor measured during the June 4-5, 2010 test (Run 1 was omitted). The total particulate emissions were measured at the stack during the baseline test for Unit 5 & 6. This emission rate (152.87 lb/hr) was divided in half to obtain the individual emission factor for Unit 5 and Unit 6. PM10 and PM2.5 were not measured at the stack, but were measured at the Unit 6 ESP outlet. Shaw assumed that the particulate speciation for Unit 5 was the same as that measured for Unit 6. The June 4-5, 2010 baseline test on Unit 6 ESP outlet showed that 83% of particulate was PM10 and 13% was PM2.5.

The future projected emissions from material handling of the SBC and the increase in particulate emissions from the boilers does not change from Scenario 1. The results of the Scenario 2 analysis are shown in Table 3-27.

Table 3-27 - Scenario 2 PSD Analysis Results

	Pollutant	Units	Value	Increase from Baseline	Federal Threshold for Significant Emissions Increase (1)	Exceeds Significant Emissions Increase Thresholds? Y/N
Baseline Actual Emissions Unit 5 and 6 Only (ton/yr)	PM	ton/yr	626.35	-	-	-
	PM10	ton/yr	469.54	-	-	-
	PM2.5	ton/yr	117.66	-	-	-
Future Projected Emissions Unit 5 and 6 Only (ton/yr)	PM	ton/yr	934.37	308.02	25	Y
	PM10	ton/yr	600.17	130.63	15	Y
	PM2.5	ton/yr	123.06	5.40	10	N/Y (2)

Notes:

(1) This is the total plant threshold limit. If all six boilers are retrofitted then this limit would be reduced to a third of what is shown for the emissions from Units 5 and 6.

(2) If all six units were retrofitted this increase would exceed the threshold in total plant emissions.

Although the facility would still trigger PSD in Scenario 2, the baseline emissions are higher because the emission factors measured during the baseline test are higher than the emission factors used for the previous year's emission inventories. Joppa may consider improving the efficiency of the particulate control so that there is no change in emissions due to the SBC loading. The same analysis that was done for Scenario 1 was done for this scenario. Since the baseline emissions are higher in this scenario, the control efficiency required to avoid PSD is 99.34% (based on PM). The PM emissions would then be:

Unit 5: 10,294 lb/hr * (1-0.9934) * 8381 hr/yr / 2000 lb/ton) = 284.70 ton/yr
Unit 6: 12,822 lb/hr * (1-0.9934) * 8008 hr/yr / 2000 lb/ton) = 338.84 ton/yr

Total emissions from the two boilers will be approximately 623.54 tpy and the net emissions increase from the boilers would be zero.

3.4.3 ESP Upgrade Considerations

The following presents a discussion of the existing electrostatic precipitators (ESP) at the Joppa Station, and a discussion of generic methods typically considered to reduce particulate matter (PM) emissions from generic existing ESPs when Trona or sodium bicarbonate (SBC) sorbent is injected upstream of an ESP to reduce sulfur dioxide (SO_2) emissions.

Joppa Existing ESP Description

Attachment 9, provided by EEI Joppa Station, presents information concerning the existing ESPs at the Joppa Station. As shown, in Attachment 9, the units burn PRB coals, and each unit employs a cold-side ESP, originally provided by Research-Cottrell (R-C), and subsequently modified by Environmental Elements and BHA in the 1990's, with a total specific collection area (SCA) of approximately 170 (ft2/kacfm, based on flue gas at ~ 330 deg F avg). Each ESP has two chambers, plate to plate spacing of 9 inch, with five electrical fields, three mechanical fields, five transformer rectifier sets (TRs), operating at 60 Hz, with R-C TRs on the first three fields, and NWL TRs on the last two fields, smooth wire discharge electrode, and Magnetic Impulse Gravity Impact (MIGI) type rappers (plate and wire). The ESPs employ flue gas conditioning (FGC) based on injection of sulfur trioxide (SO_3) in the flue gas upstream of the ESP. The ESP hoppers arrangement is first row (under fields 1&2) and second row (under fields 3 to 5) configuration, with a primary fly ash removal system of the dry pressure pneumatic type (United Conveyor Company, UCC Dry, Nuva Feeder Pressure Pneumatic) and a secondary fly ash removal of the wet vacuum type (UCC, Wet Vacuum). As described in Attachment 9, the total secondary power to ESP is typically consistent within the range of 249 to 269 kW, with consistent total secondary current density within the range of 44 to 48 mA/1000 ft^2. Per Attachment 9, typically, all the TRs are functioning properly, which is indicative of good operations and maintenance procedures. It has been reported that the ESP are routinely inspected and maintained properly during plant outages. As described in Attachment 9, ESP fields 1 and 2 employ Variable Inductance-Current Limiting

Reactors (VI-CLRs). Also, the ESPs employ BHA provided SQ-300 controllers, which are a type of automatic voltage control, that typically also includes performance monitoring and/or enhancement features, based on microprocessors, computing, and other techniques. As indicated, the existing ESPs employ a combination of original components plus relatively recent upgrades.

As shown in Attachment 9, the ESP systems typically achieve 99^{+}% PM removal, which is considered an impressive high value, considering the aforementioned relatively low SCA value of the ESPs (i.e. 170), and the highly resistive fly ash from PRB coals. The use of the FGC system (SO_3 injection) has been found useful in minimizing stack PM emissions and stack opacity.

It is apparent that much successful work has already been done on the design and the modifications of the ESPs to achieve the currently good levels of PM removal at Joppa Station. Since modifications have already been performed on the ESPs, along with high standards of operation and maintenance (O&M), with routine inspections and repairs that have maximized the efficiencies of the existing ESPs, future improvements in the performance of the existing ESPs will require additional upgrades. The following is a list and description of potential improvements/replacements to the existing ESPs. It is likely that many of these potential changes will not be technically or commercially suitable for Joppa.

Generic ESP Upgrade Considerations

With regard to upgrading a generic existing cold-side ESP that is to employ Trona or SBC dry sorbent injection upstream of the ESP for SO2 reduction, this section provides wide-range of concepts that are generally considered. Typically in a site specific ESP analysis, this general list is evaluated technically and economically to develop a shorter list that may be applicable for a given ESP.

As discussed earlier in the report, the use of Trona or SBC injection upstream of an ESP represents a significant amount of sorbent solids increased loading (lb/hr) relative to the normal amount of PRB coal fly ash that enters an ESP. Typically, the use of Trona or SBC would increase the electrical conductance of the total solids entering the ESP (flyash plus sorbent), which in general is good for ESP performance (up to a point), but to high of particle conductance is not considered good for overall ESP performance. Other potential negative attributes of Trona or SBC sorbent injection with regard to potential degraded ESP performance typically include the relatively large quantity of sorbent solids injected (lb/hr sorbent), the possible influence on particle size distribution of solids entering the ESP, the possible mal-distribution of sorbent injection across the inlet face of the ESP, and other factors. Therefore, it is possible that as a result of Trona or SBC sorbent injection (for the purpose of SO_2 reduction) the net result on ESP performance could be an increase in ESP outlet mass flow (lb/hr) of total PM and possible increase in fine PM emissions.

Table 3-28 presents a typical list of generic categories of concepts that could be considered for technical and economic attribute evaluation, at a generic ESP that is to employ Trona and/or SBC sorbent injection for SO_2 reduction. These ideas are not presented in order of preference, since it is shown as examples for a generic ESP scenario. Additional study is required to determine applicability or specific costs of these concepts for a given ESP. Later in this section, generic rough budgetary cost estimates are provided for some of these concepts at a generic 180 MW cold side ESP with PRB coal and Trona/SBC sorbent injection for SO_2 reduction.

Table 3-28 - General List of Concepts for Existing Generic Cold-Side ESP Upgrades

Generic Concept Name	Generic ESP Potential Upgrade Concept	Summary Description of General Concept
A	*Upgrading Standard TRs to High Frequency Power Supplies*	In certain cases, high frequency power supplies increase average power into the ESP, and have a faster control response. For an example, in a generic ESP, some or all TR's can be replaced by high frequency power supplies to improve performance in all fields. This approach employs a source power and controls with a much higher frequency than line frequency. These supplies rectify the 60 Hz line voltage, filter it to DC, then convert the DC power to a much higher frequency before it passing through the high-voltage step-up transformer. This conversion to a higher frequency allows for a smaller transformer and core, saving weight and size, which could avoid or minimize the need to increase the capability of the foundation during a rebuild of a generic ESP. High-frequency power supplies are presented here for information; whether they improve ESP performance would need to be determined. In some applications, it may produce improved performance because the average voltage approaches the peak voltage; and hence, these supplies may increase the effective power level in the generic ESP.
B	*Additional Sectionalization*	By sectionalizing a generic ESP, individual electrical fields are able to operate at an optimal level required for that section. In general more electrical sectionalization allows a generic ESP to react better to various flue gas conditions. This concept includes additional sectionalization along with new high frequency power supplies to further improve performance of a generic ESP.
C	*Additional Rapping*	If required, for a generic ESP, additional rapping points may help clean the plates which will fill up faster due to the higher inlet loading caused by the Trona/SBC sorbent injection. Obviously, evaluation and/or internal inspection may be required to determine the required rapping density.

Table 3-28 - General List of Concepts for Existing Generic Cold-Side ESP Upgrades		
Generic Concept Name	**Generic ESP Potential Upgrade Concept**	**Summary Description of General Concept**
D	*CFD Model Study*	Computational Fluid Dynamic (CFD) model studies of flow through a generic ESP can be performed. A model study of an existing generic ESP could indicate areas of possible re-entrainment, high velocity, and non-uniform flow distribution. Correcting these issues with vaning and perforated plate modifications could improve generic ESP performance.
E	*Discharge Electrode Design*	Retrofit of new discharge electrodes with custom configuration could be considered. Various discharge electrode designs are available for evaluation to potentially improve performance of a generic ESP.
F	*Rebuild ESP with Wide Space Spacing*	Conversion of a generic ESP from 9 inch plate to plate spacing to wider spacing such as 12 inch and/or 16 inch spacing could be considered. This can be coupled with a change in discharge electrode design to optimize performance. Generic advantages may include reduced weight of the ESP internals; improved plate alignment because allowable tolerances are greater; more uniform current density distribution; and possible improvement in collecting high-resistivity particles. In some cases, rebuilding with wider plate spacing may not require replacing the foundation. The high-voltage distribution system must be redesigned and installed. Obviously, this is a major project.
G	*Rebuild ESP – As Is*	Rebuilding an ESP is a generic concept that may be considered if the ESP was originally well-designed and is now in need of a re-build. Often, this concept alone may not be chosen, because typically an upgrade of the ESP is also required for generic scenarios. Obviously, this would be a major project.
H	*ReBuild ESP with Increased Collecting Electrode Area*	Rebuilding a generic ESP with increased collecting electrode area could be considered, through installing taller collecting plates and/or adding an extra collecting field. Even though some original generic ESP designs may have included space to install an extra field in the original casing and accounted for the extra weight this would entail, a rebuild for increased collection efficiency will usually require a major overhaul possibly including a new foundation for the new portion of the generic ESP and auxiliary equipment as needed. Obviously, this is a major project.

Table 3-28 - General List of Concepts for Existing Generic Cold-Side ESP Upgrades

Generic Concept Name	Generic ESP Potential Upgrade Concept	Summary Description of General Concept
I	*Build Additional ESP downstream of Existing ESP*	Building an additional ESP downstream of the existing generic ESP could be considered. Obviously, this is a major project. The new additional ESP would be tied-in during a unit outage.
J	*Agglomerator Concept*	Particulate matter particle agglomerator concepts, such as provided by Indigo or others, could be considered. The Indigo Agglomerator technology uses a combination of electrostatic and fluidic processes to remove the fine particles from the gas stream immediately prior to entering an ESP. The fine particles are attached to the larger particles, which are more easily collected in the generic ESP. The Indigo Agglomerator has two sections, the bipolar charger followed by the mixing section. The gas flow is split into a number of streams, each of which enters a passage in the charger section of the Agglomerator. Alternate passages are positive or negative charging. That is, the even passages may be positive and the odd passages negative, or visa versa. Following the charger a mixing process takes place, such that the fine particles leaving the positive passages are diverted into the stream of large particles leaving the negative passage and the fine particles from the negative passage are diverted into the stream of large particles leaving the positive passage. Thus the oppositely charged particles are brought within close proximity of each other causing them to electrostatically attach to each other. These agglomerates then enter the generic ESP where it is collected. This would be considered a major project.
K	*Pulse or Intermittent Energization Concepts*	The concept of using pulse energization (PE) or intermittent energization (IE) could be considered for a generic ESP. PE and IE energization are intended to provide the highest value for the product of the peak and average value of electric field at the permissible current density allowed by the ash resistivity when the resistivity is relatively high. PE provides for a more uniform current density distribution along the corona (discharge) electrode, but would require an extra power supply for each electrical field. IE does not provide a more uniform current density distribution; rather, IE applies one cycle of the input waveform, then skips several cycles on a repetitive basis to yield a product of peak and average voltages that is greater than for conventional full wave or double half-wave energization. In some cases, PC-based

Table 3-28 - General List of Concepts for Existing Generic Cold-Side ESP Upgrades

Generic Concept Name	Generic ESP Potential Upgrade Concept	Summary Description of General Concept
		control can be programmed to operate in IE mode. PE or IE is may be investigated for highly resistive ash, and may or may not be considered for the more conductive ash resulting from Trona/SBC injection.
L	*Convert ESP (COHPAC)*	Conversion of a generic ESP to a Compact Hybrid Particulate (COHPAC) design could be considered. This EPRI-developed technology uses a small pulse-jet fabric filter (PJFF) as a polishing unit downstream of the ESP. The low ash loading to the baghouse allows it to use a higher gas velocity than is needed for a baghouse operating alone. There are two ways to apply the concept. COHPAC I retains the existing ESP and adds the PJFF downstream on its own foundation, whereas COHPAC II replaces the outlet field of the ESP with the PJFF. Obviously, these are considered major projects.
M	*Build Wet ESP Downstream of Existing ESP*	Building a wet ESP (WESP) downstream of the existing generic cold-side dry ESP could be considered. WESP employs a flowing sheet of water to entirely cover the collecting plates in the ESP. Since the film of water serves as the collecting electrode, there is no significant re-entrainment and the detrimental effects of high resistivity are eliminated. The collected material flows down the plate with the water film to a drain system. The wet system can be installed either as a conversion of the outlet field of the generic existing ESP or as a separate housing downstream from the primary generic ESP collector. If the wet unit is installed in the existing housing, the existing dry field will have to be removed and replaced with a field made of corrosion-resistant materials. WESP could be considered as a polishing unit. Obviously, this is a major project.
N	*Replace Existing ESP with a Larger Cold Side ESP*	The demolition and replacement of the generic existing ESP could be considered if site conditions are limited. Again, obviously, this is a major project.
O	*Build a Fabric Filter System Downstream of Existing ESP*	Building a pulse jet fabric filter (PJFF) downstream of the existing generic ESP could be considered. The PJFF would be tied-in during unit outage. This would be a major project.
P	*Convert the Existing ESP to a Fabric Filter System*	Conversion of the existing generic ESP to a PJFF could be considered. This would require a major unit outage and would be a significant project.

Table 3-28 - General List of Concepts for Existing Generic Cold-Side ESP Upgrades

Generic Concept Name	Generic ESP Potential Upgrade Concept	Summary Description of General Concept
R	*Other Concepts*	It is possible that other generic concepts could be conceived to improve the performance of a generic ESP associated with Trona or SBC sorbent injection for SO_2 reduction.

As a means of developing rough cost estimates for some of the Table 3-28 ESP improvement concepts, Shaw contacted Hamon Research Cottrell to obtain their typical rough budgetary indicative cost estimates, expressed on an installed basis, for a generic 180 MW cold side ESP (not for any specific ESP application) that will employ Trona or SBC injection for SO_2 reduction. The client name, power plant name, or location were not identified to the ESP vendor, but instead described as a confidential generic study scenario.

Concept A - Upgrading Standard TRs to High Frequency Power Supplies
As discussed, in certain cases, high frequency power supplies may increase average power into the ESP, and have a faster control response. For an example, if all the TR's are assumed replaced by high frequency power supplies to improve performance in all fields, the budgetary indicative price could be approximately $100,000 per high frequency power supply installed. For a generic 180 MW unit existing cold-side ESP with a total of five TR sets, the ESP vendor generic price may be **$500,000 per ESP** (installed basis), not including generic Owner costs, or contingency.

Concept B - Additional Sectionalization
As indicated in Table 3-28, by sectionalizing a generic ESP, individual electrical fields may be able to operate at an optimal level required for that section. In general more electrical sectionalization allows a generic ESP to react better to various flue gas conditions. This concept includes additional sectionalization along with new high frequency power supplies to further improve performance of a generic ESP. For example, the budgetary indicative cost estimate could be approximately $80,000 pr high frequency power supply installed. For a generic 180 MW unit existing cold-side ESP, desiring to employ two new smaller high frequency power supplies (per each original larger TR set) for the sectionalization, there could be a total of ten high frequency power supplies installed, resulting in a ESP vendor generic price of approximately **$800,000 per ESP** (installed basis) for sectionalization with new high frequency power supplies, not including generic Owner costs, or contingency.

Concept C - Additional Rapping
If required, at a generic ESP, additional rapping points may help clean the plates which will fill up faster due to the higher inlet loading caused by the Trona/SBC sorbent injection. As indicated, evaluation and/or ESP internal inspection may be required to determine the required rapping density. Depending on the specifics of generic ESP, depending on the exact rapper configuration and the envil beam arrangement, the

budgetary indicative price could be approximately $3,000 per rapper, depending on control requirements. For an example of a generic "maximum case scenario", one could assume doubling the number of existing rappers. For a generic 180 MW existing cold-side ESP, with 100 plate rappers and 30 wire rappers, the ESP vendor generic price could between **$300,000 per ESP** if only the plate rappers are doubled in quantity or if wire build-up is indentified as a potential issue, it could be approximately **$390,000 per ESP** if both the plate and wire rappers are doubled in quantity. This does not include generic Owner costs, or contingency.

Concept D – CFD Modeling

As discussed in Table 3-28, Computational Fluid Dynamic (CFD) model studies of flow through a generic ESP can be considered. A model study of an existing generic ESP could indicate areas of possible re-entrainment, high velocity, and non-uniform flow distribution. Correcting these issues with vaning and perforated plate modifications could improve generic ESP performance. A generic ESP vendor price for such an initial CFD model could be approximately **$40,000 per generic cold-side ESP** sized at 180MW, depending on the complexity of the CFD model. As indicated, this does not include generic Owner costs, contingency, or potential follow-up work.

As stated, this section has presented a typical list of generic categories of concepts that could be considered for technical and economic attribute evaluation, at a generic ESP that is to employ Trona and/or SBC sorbent injection for SO_2 reduction. Additional study is required to determine applicability, degree of improvement (if any), or specific costs of these concepts for a given ESP.

3.4.4 Byproduct Handling and Landfill Considerations

Information from the current plant ash handling contractor indicates that approximately 4.1 tons of ash/hr/plant is typically received in silos over a 60 hour weekend period. That equates to approximately 1500 tons of ash accumulated in the silos with a maximum current facility capacity of 1800 tons. If, for example, a DSI rate of 5000 lb/hr is chosen, then an additional 2.5 tons of by-product would be generated per hour per plant. Thus up to an additional 900 tons per weekend need to be planned for in the by-product area. One large silo or two of current size would possibly need to be added. Alternately, the byproduct handling operation would need to expand to a six day week for disposal.

We note that during the testing with up to 12,000 lb/hr being injected into one unit, there were no reports of adverse impact on the pneumatic by-product transport system.

The characterization of the resultant ash/DS mixture indicates that the ash produced with DSI should be suitable for disposal at the new station landfill. Care will need to be taken concerning the addition of water for dust suppression at the dustless unloader and additional water added at the landfill to obtain the desired mechanical properties of the compacted ash.

The pH of the runoff from the Ash/SBC byproduct will likely be higher than what is acceptable for discharge so that a pH neutralization system may be required to treat landfill runoff prior to discharge.

Dissolution of a portion of the compacted flyash/SBC mixture was seen during the testing. Dissolution of the product will result in higher total dissolved solids (primarily sodium and sulfate) in the landfill runoff and possibly loss of structural integrity of the landfill over the long term. Adequate cover of this material will be required to minimize this dissolution in the landfill so that it maintain its structural integrity. Continued contact of the ash/SBC mixture with water produced hydrogen gas. Gas generation would be controlled with adequate cover of this material.

3.4.5 General Impacts on Plant Operation

The injection of DSI did not have any discernable impacts on the operation of Units 5 and 6. One of the questions that this study wanted to address was the potential impacts DSI would have on the air heater if injected before the air heater. However, the majority of DSI was after the air heater. No impact to the air heater performance from the limited amount of dry sorbent injected upstream of the air heater could be discerned from available data.

An inspection of A side of Unit 5 ESP after the testing was completed showed a lighter shade of ash on the internals, but no operational problems.

Though the plant did not have problems with the increased amount of ESP ash during the tests, the ESP ash removal equipment is likely undersized. The plant could not have continued dry sorbent injection around the clock for an extended period of time due to the buildup of ash within the ESP hoppers. Based on the time required to evacuate the ESP hoppers, the plant would have fallen behind based on the existing system capacity.

The delivery of pre-milled SBC did have unloading problems due to the clumping of the SBC caused by humidity and age of the pre-milled SBC. If SBC were to be used, on-site milling should be considered.

The operation of a DSI system would likely result in the plant needing additional personnel to off-load the rail delivered dry sorbent and to maintain the operation of the injection systems.

3.5 Cost Issues

3.5.1 Capital Cost Issues

If the plant were to install a DSI system at Joppa, installed equipment would likely include:

- A rail car unloading system potentially with additional trackage required to accept rail delivery of the Dry sorbent located on the north side of the plant with a pneumatic feed system to transfer the DSI to Unit-pair specific storage silos
- Upgrade of the ESP ash handling systems
- Three dry sorbent feed systems, one for each set of two units including:
    - Storage silo
    - 2- 100% (unit basis) mills located in a sound enclosure
    - 3 - 100 % (unit basis) feed valves (one spare per pair of units)
    - Compressed air system located in a sound enclosure
    - Cross connection piping within each system to feed the units for redundancy
    - Injection piping and lances

Additional capital costs would be required to increase the efficiency of the ESPs to control particulate emissions or to add additional particulate removal systems so that the plant does not trigger PSD.

3.5.2 Operating Cost Considerations

The major operations and maintenance costs for a DSI system will be the purchase of DSI.

Based on the following economic factors the annual costs for the 6 unit plant associated with DSI purchase was estimated for the various Dry Sorbent options examined in this study; the results are shown in Table3-29:

- Plant capacity factor of 90%
- Average coal SO_2 content of 0.61 lb SO_2/MMBtu
- 50% SO_2 removal required
- Trona delivered price of $175/ton, SBC delivered price of $200/ton

Table 3-29 - Estimated Annual Cost of Dry Sorbent

Dry Sorbent	Injection Location	Dry Sorbent Cost ($/ton)	Lb SO_2 removed per lb of Dry Sorbent	Yearly Cost of Dry Sorbent (1)
Un-milled Trona	Before Air heater	$ 175	0.093	$ 23,483,829
Milled Trona	Before Air heater	$ 175	0.10	$ 21,839,961
Milled Trona	After Air heater	$ 175	0.049 (2)	$ 44,571,349 (2)
SBC	Before Air heater	$ 200	0.16 (3)	$ 15,599,972 (3)
SBC	After Air heater	$ 200	0.12	$ 20,799,963

Notes:

1. Based on 50% SO_2 removal with plant burning PRB coal with 0.61 lbs of SO_2/MMBtu and a yearly plant capacity factor of 0.90
2. The data for milled Trona injection after the air heater is minimal. This utilization rate achieved an average of 42.6% SO_2 removal. The utilization rate would likely be higher to achieve 50% removal, so the yearly estimated cost would likely be higher than shown to achieve 50% SO_2 removal.
3. The data for SBC injection before the air heater is minimal. This utilization rate achieved an average of 67% SO_2 removal. The utilization rate would likely be lower to achieve 50% removal, so the yearly estimated cost would likely be lower than shown to achieve 50% SO_2 removal.

Additional O&M costs will occur for additional plant personnel, the lost revenue of fly ash sales, the additional costs associated with disposal of the mixed ash/DSI product and additional electrical parasitic load.

4 Conclusions and Recommendations

As stated in the beginning of this study there were several key issues that this study tried to answer. These included:

- whether continuous 50% or better SO_2 reduction and continuous 90% mercury removal can be achieved during normal plant operations including turn down of the units due to market demands;
- whether the use of a dry sorbent will impact the level of acid gases and heavy metals in the flue gas;
- whether there is an impact to the air heaters (if upstream of the air heaters was the selected DSI point);
- whether there is an impact to the ESP from either DSI reagent;
- whether there is an impact to the operation of the fly ash handling system, and;
- whether there are any issues in the handling of DSI that would cause undue hardship on the plant operation.

4.1 Conclusions

4.1.1 Plant Emissions Impacts

- Greater than 50% SO_2 removal was obtained with un-milled Trona, milled Trona before the air heater and with SBC before or after the air heater.
- 50% removal was not seen with milled Trona after the air heater
- SBC had a better utilization efficiency than Trona whether milled or un-milled with a 0.158 lbs SO2 removed per lb of dry sorbent versus 0.100 lbs SO2 removed per lb of dry sorbent for milled Trona when injection was before the air heaters
- Milled Trona was more efficient than un-milled Trona in SO_2 removal (ratio averages 0.100 vs. 0.093, lbs SO2 removed per lb of dry sorbent respectively) when injected before the air heater
- The injection location (whether before or after the air heater) impacts the efficiency of Trona and SBC utilization, with injection before the air heater having a significantly greater utilization efficiency
- Dry sorbent injection will reduce acid gases; 80+% removal was seen in these tests
- For mercury emissions, baseline testing showed a greater than 90% mercury removal. Mercury removal in the final SBC testing on Units 5 and 6 was also greater than 90%. However, mid 80% mercury removals were seen during other portions of the test program, which results in uncertainty regarding the effects of DSI on mercury removal
- The addition of DSI will increase the amount of particulate matter leaving the stacks. The Joppa facility will trigger PSD due to injection of the dry sorbent and DSI material handling unless the control efficiency of the existing particulate control is increased.

- There was also a slight increase in opacity when burning Belle Ayr coal, but the increase did not affect the plant's permit compliance.

4.1.2 Plant Operational Impacts

- The majority of DSI occurred after the air heaters. The limited amount of DSI before the air heaters did not cause any noticeable operational impact. Whether long term injection of dry sorbent before the air heaters will cause degradation of plant performance is unknown. Visual inspection of a portion of the Unit 5 ESP after the tests did not show any issues with DSI. Long term effects on the ESPs that may result from DSI are unknown.
- The only operational issue concerning the handling of the DSI was the clumping of the pre-milled SBC which caused extended unloading durations. If SBC were to be used in a future DSI system, then the on-site system should include a milling operation.
- In addition to capital cost requirements to install the DSI system and supporting infrastructure and to increase the efficiency of the existing ESPs or install new particulate control measures, the annual cost for the dry sorbent will be at least $16,000,000 per year and possibly higher depending on dry sorbent selected

4.1.3 By-Product Handling Impacts

- The increase in fly ash generated with DSI will require increased capacity of the fly ash handling system's daily operation, and/or additional storage
- The resultant byproduct is landfillable. However the fly ash handling operation and landfill operation will require the following:
    - The by-product should be wetted in a two stage approach where a portion of the water is added at the dustless unloader for dust control and the remaining water needed for optimum compaction be added at the landfill via a water truck or like conveyance system
    - The runoff pH will likely be high enough to require neutralization of the landfill pond runoff prior to discharge
    - The landfilled material will need to be managed (covered) to minimize standing water on the by-product due to its potential dissolution. The dissolution will increase the total dissolved solids in the landfill runoff potential to a point impacting its discharge permit and potentially the landfill integrity over the life of the landfill
    - The increase in total byproduct produced by the plant will reduce the life of the landfill (use up available capacity faster)

4.2 Recommendations

The following recommendations can be made:

- **Estimate the cost of particulate control upgrades for DSI options**
    - Evaluate unmilled Trona injected before the air heater with ESP upgrades to address current regulations and not trigger PSD (high risk alternative), since un-milled Trona may have less of an impact on particulate emissions than other dry sorbents.
    - Evaluate other DSI options and address future utility MACT rules by adding a helper ESP or a fabric filter downstream of the existing ESP.

- **Perform economic engineering evaluation of SO_2 control technologies for the Joppa Station**
    - Design criteria in line with expected utility MACT regulations for evaluating different options:
        - DSI with helper ESPs and fabric filters
        - Wet flue gas desulfurization
        - Dry flue gas desulfurization
        - ReACT
- If the use of DSI at Joppa is still viable after the review of ESP efficiency upgrades, then additional testing is warranted that would include:

    - Prolonged injection of each reagent upstream of the air heaters to determine potential long term impacts
    - Testing on both Units 5 and 6 so that the stack CEMs can be utilized versus induct sampling.
    - Additional mercury testing should be included
- It would be beneficial for Joppa to conduct a full PSD analysis at the conclusion of CY2010 operation using the latest emission data.

Attachment 1

Draft Report
Source Emissions Sampling Report
For Units 5 and 6 at Electric Energy, Inc.
Joppa Station
Project Number: 139424
Shaw E & I

Shaw®
a world of Solutions™

September 1, 2010

Mr. Bruce McCampbell
Shaw Power, Fossil and Renewables
100 Technology Center
Stoughton, MA 02072

Subject: Source Emissions Sampling Report for EEI at Joppa Station

Dear Mr. McCampbell:

Shaw Environmental, Inc. (Shaw) is pleased to submit this source emission sampling report to Shaw Power - Fossil and Renewables for emissions testing of the Unit 5 and Unit 6 emission source(s) at the Electric Energy, Inc. Joppa Station facility. The enclosed report details the results of the emission testing for this identified emission source, and also contains all pertinent backup field data to support the results and/or conclusions.

We appreciate the opportunity to provide our services to Shaw Power - Fossil and Renewables, and we look forward to continuing to work closely with you. If you have any questions or concerns regarding the contents of this proposal, please contact me at your convenience at 865-690-3211, or by email at russell.bryson@shawgrp.com.

Sincerely,

Russell Bryson

Russell D. Bryson, PE
Project Manager
Shaw Environmental, Inc.

312 Directors Drive, Knoxville, TN 37923
865-690-3211 / FAX: 865-694-7497

Electronic Filing - Received, Clerk's Office, 08/15/2012

Final Report

Source Emissions Sampling Report For Units 5 and 6 at Electric Energy, Inc. Joppa Station

Project Number: 139424

Submitted to:

Mr. Bruce McCampbell
Project Manager
Shaw Power - Fossil and Renewables
100 Technology Center
Stoughton, MA 02072

Date: September 1, 2010

Submitted by:

Shaw® Shaw Environmental, Inc.
Integrated Emissions Solutions Development (IESD)
312 Directors Drive
Knoxville, TN 37923

Source Emissions Sampling Report
For Sources Units 5 and 6
Electric Energy, Inc. Joppa Station

Draft Report

Certification

September 1, 2010

I certify that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to be the best of my knowledge and belief, true, accurate, and complete.

Russell Bryson

September 1, 2010

Russell D. Bryson, PE
Project Manager
Shaw Environmental, Inc.

Date

Table of Contents

Appendices:

List of Tables

List of Chemicals / Elements

SYMBOLS AND ABBREVIATIONS	ELEMENT, CHEMICAL,R CHEMICAL CONSTITUENT
Al	Aluminum
Ag	Silver
As	Arsenic
Ba	Barium
Be	Beryllium
C	Carbon
Cd	Cadmium
Cr	Chromium
Cl	Chlorine
Co	Cobalt
CO / CO_2	Carbon monoxide / dioxide
Cu	Copper
F	Fluorine
Fe	Iron
H	Hydrogen
Hg	Mercury
Hg^{2+}	Oxidized mercury
Hg_T	Total mercury
I	Iodine
K	Potassium
Mg	Magnesium
Mo	Molybdenum
Mn	Manganese
Na	Sodium
Ni	Nickel
NO	Nitric Oxide
NOx	Nitrous Oxides
O	Oxygen
P	Phosphorus
Pb	Lead
S	Sulfur
Se	Selenium
Sn	Tin
SO_2 / SO_3	Sulfur dioxide / sulfur trioxide
Tl	Thallium
Zn	Zinc

Common Acronyms

ACRONYM	DEFINITION
A	Amps
AA	Atomic Absorption
ACI	Activated Carbon Injections
AF	Atomic Fluorescence
APCD	Air Pollution Control Device
APH	Air Pre-Heater
ASTM	American Society of Testing & Materials
AQS	Air Quality Services
CEMS	Continuous Emissions Monitoring Systems
CFR	Code of Federal Regulations
CPM	Condensable Particulate Matter
CVAAS	Cold-Vapor Atomic Absorption Spectroscopy
CVAFS	Cold-Vapor Atomic Fluorescence Spectroscopy
EHS	Environmental Health & Safety
EPA	Environmental Protection Agency (U.S.)
ESP	Electrostatic Precipitator
FFBH	Fiber-Filter Baghouse
FGD	Flue Gas Desulphurization
GFAA	Graphite Furnace Atomic Absorption
ICAP	Inductively Coupled Argon Plasma
IESD	Integrated Emissions Solutions Development
IC	Ion Chromatography
LOI	Loss on Ignition
M30B	EPA Test Method 30B
NCASI	National Council for Air & Stream Improvement
OHM	Ontario Hydro Method
PM	Particulate Matter
PSA	PS Analytical
QA/QC	Quality Assurance/Quality Control
RATA	Relative Accuracy Test Audit
RCRA	Resource Conservation & Recovery Act
RFP	Request for Proposal
SCEM	Semi-Continuous Emissions Monitor
SCR	Selective Catalytic Reduction
SI	Sorbent Injections
SOW	Scope/Statement of Work
TAP	Toxic Air Pollutant
TCLP	Toxicity Characteristics Leaching Procedure
TAT	Turn-Around Time (analytical)
V	Volt
VOC	Volatile Organic Compound

1.0 Introduction

Shaw Power, Fossil and Renewables, contracted Shaw Environmental and Infrastructure (E&I) to perform emissions testing associated with permitted emission sources. This report presents the results of the tests conducted on June 4th through 15th, 2010 at the Electric Energy, Inc. (EEI) facility located in Joppa, Illinois. The primary objective of the testing was to determine the emissions of target air pollutants and to ascertain removal efficiencies across the air pollution control system during baseline and parametric testing conditions. Section 2.0 of this report provides the detailed emissions summaries for the target pollutants.

1.1 Testing Matrices

Emissions sampling was performed under the following conditions:

- Baseline: Emissions sources (Units 5 and 6) operating at normal maximum production
- Parametric: Emission sources continuing to operate at normal maximum production, with the addition of the following dry sorbent injection materials:
  - Trona (milled and unmilled)
  - Pre-Milled Sodium bicarbonate (SBC)

The testing matrix for each condition is shown in Table 1-1. Field sampling of the measured parameters conformed to the reference test methods cited in the governing regulations listed in Table 1-2.

Table 1-1
Test Schedule Matrix

			Trona Injection			SBC Injection	
			Type		Location	Location	
Date	**Task**	**Condition**	**Milled**	**Unmilled**	**U6**	**U5**	**U6**
6/4/2010	Testing	Baseline	No Injections				
6/5/2010	Testing	Baseline	No Injections				
6/6/2010	No Testing	Weekend - EEI off					
6/7/2010	Testing	Parametric		X	Before Air Heater		
6/8/2010	Testing	Parametric	X		Before Air Heater		
6/9/2010	Testing	Parametric CEMS Only	X		After Air Heater – **(a.m. only)**		After Air Heater **(p.m. only)**
6/10/2010	Testing	Steady-State					Before Air Heater
6/11/2010	Testing	Steady-State CEMS Only				After Air Heater	After Air Heater
6/12/2010	No Testing	Weekend – EEI off					
6/13/2010	No Testing	Weekend – EEI off					
6/14/2010	Testing	Steady-State CEMS Only				After Air Heater	After Air Heater
6/15/2010	Testing	Parametric				After Air Heater	After Air Heater
6/16/2010	No Testing	Unit 5 down due to steam tube malfunction – EEI halted testing					
6/17/2010	Packing and demobilization						
6/18/2010	Return travel						

Table 1-2
Reference Sampling and Analytical Methods

Sample Parameter	Citation	Sampling Method
Sampling Traverse Locations	40 CFR 60, Appendix A	Method 1
Gas Stream Volumetric Flow rate	40 CFR 60, Appendix A	Method 2
Oxygen (O_2)	40 CFR 60, Appendix A	Method 3A
Carbon Dioxide (CO_2)	40 CFR 60, Appendix A	Method 3A
Gas Stream Moisture	40 CFR 60, Appendix A	Method 4
Particulate Matter (PM as TSP)	40 CFR 60, Appendix A	Method 5
Sulfur Dioxide (SO_2)	40 CFR 60, Appendix A	Method 6C
Nitrogen Oxides (NOx)	40 CFR 60, Appendix A	Method 7E
Vapor Phase Sulfuric Acid	NCASI	Method 8A
Vapor Phase Halogen Content	40 CFR 60, Appendix A	Method 26A
Fuel Sample (Ultimate Analysis)	40 CFR 60, Appendix A	Method 19
Total Vapor Hg	40 CFR 60, Appendix A	Method 30B
Particulate Matter PM10/PM2.5	EPA	OTM-27
Condensable Particulate Matter (CPM)	40 CFR 51, Appendix M	Method 202
Hg Speciation	ASTM	D6784-02
Coal and Ash Hg Content	ASTM	D3684-01 or D6414-01
Coal Ultimate Analysis	ASTM	D3176-89, et al.
Coal Proximate Analysis	ASTM	D3172-07, et al.
Gross Calorific Value	ASTM	D5865-07
Ash Loss on Ignition (LOI)	ASTM	D7348-07

Sampling was performed on the individual combustion exhaust gas streams from Units 5 and 6 and the shared exhaust stack (Stack 3). Table 1-3 (following page) details the sampling matrix for each sample location.

1.2 Facility Description

Units 5 and 6 of the EEI Joppa Station are both 180 MW pulverized coal (PC) boilers that are fueled by Powder River Basin (PRB) coal. During the testing, the units use either Thunder River (Jacobs Ranch) or Belle Ayr PRB coal. A separated over-fire air system (SOFA) is used to control NO_X, and particulate is controlled with an electrostatic precipitator (ESP). The layout of the process equipment at the Joppa Station is shown in Figure 1-1 (see page 3).

The combustion gas stream from each unit exhausts from the boiler, through the economizer section, and through the air pre-heater prior to entering the electrostatic precipitator. The inlet duct after the economizer splits into two parallel gas streams entering the ESP. The ESP outlet consists of parallel ducting then recombines before entering the induced draft fan. The gas streams from Units 5 and 6 are combined to exit through a common shared stack.

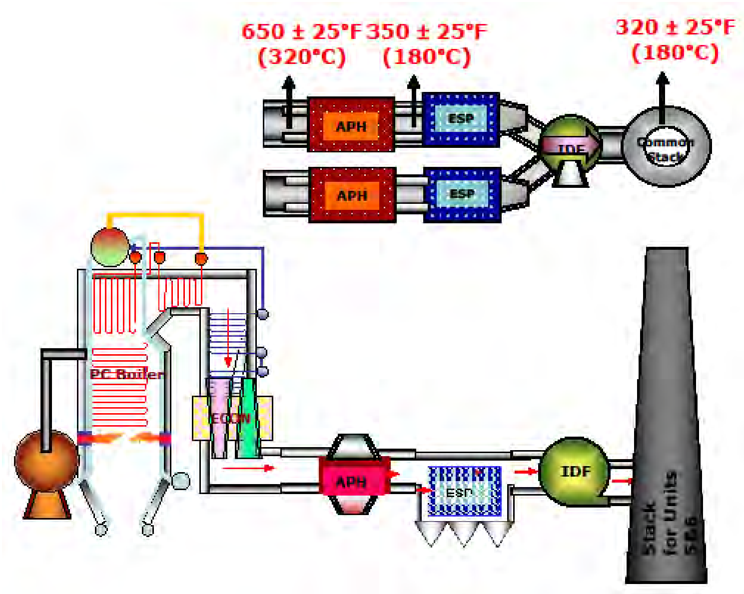

Figure 1-1 General Arrangement for Units 5 and 6

Notes:
(1) – Actual arrangement consists of two I.D. fans per unit prior to entering the common stack
(2) – Vertical flow through each APH

1.3 Sampling Locations

All single point sampling was conducted on each unit at the following locations:

- Economizer Outlet - consisted of two parallel ducts (Duct A & B) each with a cross sectional area of 230 square feet at the sampling location.
- ESP Inlet - consisted of two parallel ducts (Duct A & B) each with a cross sectional area of 230 square feet at the sampling location.
- ESP Outlet - consisted of two parallel ducts (Duct A & B) each with a cross sectional area of 250 square feet at the sampling location.
- Common Stack - single annular stack with an 18 foot diameter at the sampling location.

All CEMS (e.g. O_2, CO_2, NO_X) measurements were conducted at a single point centrally located inside Duct A of each designated sampling location (see Table 1-3), simultaneously with each wet chemistry method (e.g. PM, Hg). Wet chemistry sampling trains were located at the common stack and a single centralized location inside Duct B of each sampling location (see Table 1-3).

1.4 Operating Conditions

During the testing program, the facility operated under the following conditions, and noted in Table 1-4 (see page 5).

Table 1-3
Emissions Sample Train Location Matrix

				Shaw Sample Trains								
Date	**Unit**	**Location**	**Condition**	**M5**	**OHM**	**CEMS**	**M29**	**M26A**	**M8A**	**M30B**	**M5/202**	**OTM-27**
6/4/2010	5	ESP Inlet	Baseline	✓								
	6	Econ Outlet			✓	✓						
		ESP Inlet		✓								
		ESP Outlet			✓	✓						✓
	Units 5&6	Stack 3			✓		✓	✓	✓	✓	✓	
6/5/2010	Unit 5	ESP Inlet	Baseline	✓								
	Unit 6	Econ Outlet			✓	✓						
		ESP Inlet		✓								
		ESP Outlet			✓	✓						✓
	Units 5&6	Stack 3			✓		✓	✓	✓	✓	✓	
6/7/2010	Unit 6	Econ Outlet	Trona-Unmilled		✓	✓						
		ESP Inlet		✓								
		ESP Outlet			✓	✓						✓
6/8/2010	Unit 6	Econ Outlet	Trona-Milled		✓	✓						
		ESP Inlet		✓								
		ESP Outlet			✓	✓						✓
6/9/2010	Unit 6	Econ Outlet	Trona-Milled			✓						
		ESP Inlet				✓						
6/9/2010	Unit 6	Econ Outlet	SBC			✓						
		ESP Inlet				✓						
6/10/2010	Unit 6	Econ Outlet	SBC		✓	✓						
		ESP Inlet		✓								
		ESP Outlet			✓	✓						✓
6/11/2010	Unit 6	Econ Outlet	SBC			✓						
		ESP Outlet				✓						
6/14/2010	Unit 5	Econ Outlet	SBC			✓						
	Unit 6	ESP Outlet				✓						
6/15/2010	Unit 5	Econ Outlet	SBC		✓	✓						
	Unit 5	ESP Inlet		✓								
	Unit 6	Econ Outlet			✓	✓						
		ESP Inlet		✓								
	Units 5&6	Stack 3			✓	✓	✓	✓	✓	✓	✓	

Table 1-4
Units 5 and 6 Operating Conditions (PI Data)

Date	Run #	Unit 5 Load MW	Unit 6 Load MW	Units 5 & 6 Total Load MW	Total Flow @ Stack mmscfh	DSI Type	Injection Location	Average Injection Rate (lb/hr)
6/4/2010	1	174.5	181.91	356.4	54.18	Baseline	N/A	N/A
6/4/2010	2	175	182.4	357.35	54.43	Baseline	N/A	N/A
6/5/2010	3	171.2	180.56	351.75	53.68	Baseline	N/A	N/A
6/5/2010	4	174.1	180.46	354.54	53.91	Baseline	N/A	N/A
6/7/2010	1	172.5	181.86	354.38	53.94	un milled Trona	before air heater	5,971
6/7/2010	2	172.5	182.28	354.82	53.94	un milled Trona	before air heater	11,659
6/7/2010	3	171.1	182.5	353.63	53.73	un milled Trona	before air heater	10,219
6/8/2010	1	180.4	183.51	363.89	54.63	milled Trona	before air heater	8,838
6/8/2010	2	179.8	183.58	363.38	54.88	milled Trona	before air heater	8,561
6/8/2010	3	176	183.9	359.9	54.11	milled Trona	before air heater	8,688
6/9/2010	1	177.6	185.14	362.79	54.45	milled Trona	after air heater	14,237
6/9/2010	2	177.7	184.63	362.31	54.29	SBC	after air heater	11,643
6/10/2010	1	175.6	182.67	358.22	53.91	SBC	before air heater	7,733
6/10/2010	2	176.4	182.06	358.49	53.99	SBC	before air heater	7,275
6/10/2010	3	178.5	182.13	360.63	54.21	SBC	before air heater	6,921
6/11/2010	1	173.3	181.74	355.06	54.01	SBC	after air heater	5,882
6/11/2010	2	173.7	178.42	352.14	53.61	SBC	after air heater	11,077
6/11/2010	3	173.7	180.96	354.64	53.84	SBC	after air heater	14,665
6/14/2010	1	173	181.43	354.4	53.95	SBC	after air heater	9,284
6/14/2010	2	173	181.21	354.21	53.77	SBC	after air heater	9,683
6/15/2010	1	175.5	182.21	357.69	53.1	SBC	after air heater	10,200
6/15/2010	2	175.6	182.15	357.71	54.12	SBC	after air heater	9,956
6/15/2010	3	174.3	183.28	357.62	54.36	SBC	after air heater	10,438

2.0 Summary of Results

As noted in Section 1.0 of this report, the primary objective of these tests was to determine the emission rates of target air pollutants and to ascertain removal efficiencies across the air pollution control system during baseline and parametric testing conditions. Therefore, emissions sampling was performed under the following conditions:

- Baseline: Emissions sources (Units 5 and 6) operating at normal maximum production
- Parametric: Emission sources continuing to operate at normal maximum production, with the addition of the following dry sorbent injection materials:
  - Trona (milled and unmilled)
  - Sodium bicarbonate (SBC)

The specific pollutants and data parameters determined from the testing were:

- Sulfur dioxide/sulfur trioxide (SO_2/SO_3) – mass emission rates, removal efficiency
- Oxides of nitrogen (NO_X) – mass emission rates
- Total particulate matter (PM), speciated PM (PM10/PM2.5), and condensable particulate matter (CPM) – mass emission rates, removal, and control efficiency
- Mercury speciation [total mercury (HgT), elemental mercury (Hg^0), and oxidized mercury (Hg^{+2})] – mass emission rates, removal efficiency
- Halogens and hydrogen halides (Cl_2, HCl, HF) – mass emission rates and concentrations
- Air toxic metals – mass emission rates

The following sections provide pollutant-specific results and observations.

2.1 Sulfur Dioxide (SO_2)

Using EPA Method 6C, sulfur dioxide (SO_2) concentrations were measured in the gas stream at the selected sample location. The SO_2 emission rates were calculated and are reported here in units of *lb/hr* and *lb/MMBtu*. Gas stream concentrations are reported in parts per million by volume, dry basis *(ppmvd)*. In addition to the mass emission rates, the test data was used in conjunction with the dry sorbent injection (DSI) feed rates to determine removal efficiencies in units of pounds of SO_2 removed per pound of DSI *(lb SO_2/lb DSI)*. Secondary removal efficiency was estimated based on the mass emission rates determined from the economizer (ECON) outlet, electrostatic precipitator (ESP) outlet, and stack. Table 2-1 shows the SO_2 test results.

Table 2-1
SO_2 Concentrations, Mass Emission Rates and Removal Efficiency

Date	Sample Location	Run	Shaw CEMS Corrected Concentrations			SO_2 Removal %
			SO_2 ppmvd	SO_2 lb/MMBtu	SO_2 lb/hr	
6/4/2010	U6 ECON Outlet	1	641.1	1.258	1,587.3	
6/4/2010	U6 ESP Outlet	1	442.6	0.970	1,950.8	0.0%
6/4/2010	U6 ECON Outlet	2	442.2	0.867	1,095.6	
6/4/2010	U6 ESP Outlet	2	321.5	0.967	1,420.3	0.0%
6/5/2010	U6 ECON Outlet	3	456.4	0.893	1,221.5	
6/5/2010	U6 ESP Outlet	3	304.3	0.917	1,317.0	0.0%
6/5/2010	U6 ECON Outlet	4	461.6	0.903	1,387.3	
6/5/2010	U6 ESP Outlet	4	436.0	0.976	1,923.4	0.0%
6/7/2010	U6 ECON Outlet	1	529.5	1.037	1,645.0	
6/7/2010	U6 ESP Outlet	1	286.7	0.648	1,253.0	23.8%
6/7/2010	U6 ECON Outlet	2	510.8	1.002	1,678.3	
6/7/2010	U6 ESP Outlet	2	215.4	0.486	980.3	41.6%
6/7/2010	U6 ECON Outlet	3	522.8	1.024	1,711.2	
6/7/2010	U6 ESP Outlet	3	237.3	0.535	1,087.1	36.5%
6/8/2010	U6 ECON Outlet	1	406.7	0.795	1,420.0	
6/8/2010	U6 ESP Outlet	1	195.5	0.445	894.2	37.0%
6/8/2010	U6 ECON Outlet	2	468.9	0.913	1,631.3	
6/8/2010	U6 ESP Outlet	2	154.7	0.432	692.0	57.6%
6/8/2010	U6 ECON Outlet	3	479.4	0.947	1,647.9	
6/8/2010	U6 ESP Outlet	3	160.0	0.451	699.1	57.6%
6/9/2010	U6 ECON Outlet	1	541.8	1.062	2,134.3	
6/9/2010	U6 ESP Outlet	1	271.5	0.626	1,074.5	49.7%
6/9/2010	U6 ECON Outlet	2	475.0	0.933	1,870.1	
6/9/2010	U6 ESP Outlet	2	244.3	0.602	964.3	48.4%
6/10/2010	U6 ECON Outlet	1	478.1	0.937	1,590.3	
6/10/2010	U6 ESP Outlet	1	187.1	0.430	847.0	46.7%
6/10/2010	U6 ECON Outlet	2	442.2	0.864	1,407.6	
6/10/2010	U6 ESP Outlet	2	161.1	0.370	705.1	49.9%

Date	Sample Location	Run	Shaw CEMS Corrected Concentrations			SO_2 Removal %
			SO_2 ppmvd	SO_2 lb/MMBtu	SO_2 lb/hr	
6/10/2010	U6 ECON Outlet	3	486.2	0.949	1,470.2	
6/10/2010	U6 ESP Outlet	3	203.8	0.471	889.4	39.5%
6/11/2010	U6 ECON Outlet	1	511.3	0.999	1,992.1	
6/11/2010	U6 ESP Outlet	1	307.1	0.716	1,199.7	39.8%
6/11/2010	U6 ECON Outlet	2	514.3	1.004	1,977.0	
6/11/2010	U6 ESP Outlet	2	332.2	0.761	1,282.4	35.1%
6/11/2010	U6 ECON Outlet	3	510.9	0.997	1,980.7	
6/11/2010	U6 ESP Outlet	3	297.9	0.741	1,167.2	41.1%
6/14/2010	U5 ECON Outlet	1	230.7	0.504	859.0	46.6%
6/14/2010	U6 ECON Outlet	1	268.4	0.525	1,046.0	
6/14/2010	U5 ECON Outlet	2	227.5	0.498	847.7	50.7%
6/14/2010	U6 ECON Outlet	2	270.3	0.527	1,049.5	
6/15/2010	U5 ECON Outlet	1	224.9	0.509	1,201.7	41.0%
6/15/2010	U6 ECON Outlet	1	267.3	0.530	850.5	
6/15/2010	U5 ECON Outlet	2	198.7	0.470	980.7	50.7%
6/15/2010	U6 ECON Outlet	2	270.9	0.525	842.1	
6/15/2010	U5 ECON Outlet	3	194.0	0.469	984.6	52.8%
6/15/2010	U6 ECON Outlet	3	268.2	0.525	854.1	

2.1.1 Observations

SO_2 removal efficiencies were calculated as follows:

1. Using data generated in procedure above, SO_2 removal efficiency is calculated as follows, except as noted:

$$\text{Removal Eff\%} = \frac{\left(\text{SO2 mass rate}\left(\text{ECON OUT}, \frac{\text{lb}}{\text{hr}}\right) - \text{SO2 mass rate}\left(\text{ESP OUT}, \frac{\text{lb}}{\text{hr}}\right)\right)}{\text{SO2 mass rate}\left(\text{ECON OUT}, \frac{\text{lb}}{\text{hr}}\right)}$$

2. On 6/14 and 6/15, one of the Shaw CEMSs was relocated to the Unit 5 ECON OUT position. Therefore, SO_2 removal was calculated as follows:

$$\text{Removal Eff\%} = \frac{\left(\text{Unit 6 SO2 mass rate}\left(\text{ECON OUT}, \frac{\text{lb}}{\text{hr}}\right) + \text{Unit 5 SO2 mass rate}\left(\text{ECON OUT}, \frac{\text{lb}}{\text{hr}}\right) - \text{SO2 mass rate}\left(\text{Stack}, \frac{\text{lb}}{\text{hr}}\right)\right)}{\left(\text{Unit 6 SO2 mass rate}\left(\text{ECON OUT}, \frac{\text{lb}}{\text{hr}}\right) + \text{Unit 5 SO2 mass rate}\left(\text{ECON OUT}, \frac{\text{lb}}{\text{hr}}\right)\right)}$$

2.2 Oxides of Nitrogen (NOX)

Using EPA Method 6C, oxides of nitrogen (NO_X as NO_2) concentrations were measured in the gas stream at the selected sample locations. The NO_X mass emission rates were calculated and are reported in units of *lb/hr* and *lb/MMBtu*. Gas stream concentrations are reported in *ppmvd*. Table 2-2 shows the SO_2 test results.

Table 2-2
NO_X Concentrations and Mass Emission Rates

			Shaw CEMS Avg. Concentrations			Emissions By Site CEMS (Measured at Stack 3)		
Date	Sample Location	Run	NO_X ppmvd	NO_X lb/MMBtu	NO_X lb/hr	NO_X ppmvd	NO_X lb/MMBtu	NO_X lb/hr
6/4/2010	U6 ECON Outlet	1	148.3	0.209	349.1			
6/4/2010	U6 ESP Outlet	1	81.7	0.129	258.2	73.00	0.127	471.3
6/4/2010	U6 ECON Outlet	2	100.4	0.141	236.4			
6/4/2010	U6 ESP Outlet	2	61.6	0.133	195.0	72.12	0.126	467.7
6/5/2010	U6 ECON Outlet	3	92.8	0.131	229.0			
6/5/2010	U6 ESP Outlet	3	54.4	0.117	167.7	68.52	0.121	438.2
6/5/2010	U6 ECON Outlet	4	96.2	0.135	255.4			
6/5/2010	U6 ESP Outlet	4	77.7	0.124	244.7	73.36	0.129	471.2
6/7/2010	U6 ECON Outlet	1	99.9	0.141	223.9			
6/7/2010	U6 ESP Outlet	1	73.4	0.121	233.1	69.47	0.122	446.4
6/7/2010	U6 ECON Outlet	2	101.8	0.143	240.6			
6/7/2010	U6 ESP Outlet	2	73.4	0.120	241.7	70.06	0.122	450.2
6/7/2010	U6 ECON Outlet	3	102.7	0.144	241.3			
6/7/2010	U6 ESP Outlet	3	76.2	0.125	252.8	69.45	0.121	444.6
6/8/2010	U6 ECON Outlet	1	86.8	0.123	219.7			

Date	Sample Location	Run	Shaw CEMS Avg. Concentrations NO_x ppmvd	NO_x lb/MMBtu	NO_x lb/hr	Emissions By Site CEMS (Measured at Stack 3) NO_x ppmvd	NO_x lb/MMBtu	NO_x lb/hr
6/8/2010	U6 ESP Outlet	1	73.2	0.121	242.6	67.08	0.117	436.6
6/8/2010	U6 ECON Outlet	2	101.8	0.143	256.8			
6/8/2010	U6 ESP Outlet	2	61.3	0.123	196.8	70.71	0.123	462.4
6/8/2010	U6 ECON Outlet	3	97.0	0.137	238.3			
6/8/2010	U6 ESP Outlet	3	56.3	0.115	177.5	65.77	0.114	424.0
6/9/2010	U6 ECON Outlet	1	112.0	0.158	318.0			
6/9/2010	U6 ESP Outlet	1	71.0	0.119	203.7	67.06	0.116	435.1
6/9/2010	U6 ECON Outlet	2	102.5	0.144	289.5			
6/9/2010	U6 ESP Outlet	2	70.2	0.124	200.8	69.76	0.121	451.3
6/10/2010	U6 ECON Outlet	1	107.3	0.151	256.7			
6/10/2010	U6 ESP Outlet	1	81.2	0.134	264.3	70.02	0.123	449.7
6/10/2010	U6 ECON Outlet	2	98.2	0.138	226.1			
6/10/2010	U6 ESP Outlet	2	73.4	0.121	229.8	67.06	0.117	431.3
6/10/2010	U6 ECON Outlet	3	97.9	0.137	213.6			
6/10/2010	U6 ESP Outlet	3	72.8	0.120	225.9	70.06	0.121	452.5
6/11/2010	U6 ECON Outlet	1	96.5	0.136	272.0			
6/11/2010	U6 ESP Outlet	1	73.1	0.123	205.6	67.61	0.121	435.1
6/11/2010	U6 ECON Outlet	2	101.1	0.143	281.8			
6/11/2010	U6 ESP Outlet	2	79.1	0.133	220.3	68.94	0.122	440.3
6/11/2010	U6 ECON Outlet	3	92.3	0.130	259.7			
6/11/2010	U6 ESP Outlet	3	67.1	0.120	189.2	66.27	0.116	425.1
6/14/2010	U5 ECON Outlet	1	66.0	0.104	177.6	62.83	0.110	403.8
6/14/2010	U6 ECON Outlet	1	86.9	0.122	244.2			
6/14/2010	U5 ECON Outlet	2	69.6	0.110	188.4	62.84	0.109	402.6
6/14/2010	U6 ECON Outlet	2	89.5	0.125	250.2			
6/15/2010	U5 ECON Outlet	1	61.5	0.100	235.8	62.96	0.11	398.3
6/15/2010	U6 ECON Outlet	1	93.2	0.125	201.6			
6/15/2010	U5 ECON Outlet	2	60.1	0.102	213.1	62.63	0.11	403.8
6/15/2010	U6 ECON Outlet	2	88.9	0.123	197.4			
6/15/2010	U5 ECON Outlet	3	57.6	0.100	209.5	62.90	0.11	407.4
6/15/2010	U6 ECON Outlet	3	86.9	0.125	204.2			

2.3 Total Particulate Matter

Emissions data for the specific subsets of particulate matter (PM) were acquired as noted below. Detailed emissions results are shown in Table 2-3.

Using either one or a combination of EPA Method 5, Other Test Method 27 (OTM-27), and/or Method 202, particulate matter (PM) data were acquired per the testing matrix schedule. PM mass emission rates were calculated in units of *lb/hr* and *lb/MMBtu*. EPA Method 19's published fuel factors for sub-bituminous coal were used in calculating the mass emission rate in *lb/MMBtu*. Based on the calculated emission rates for total PM, Shaw estimated the net changes in emission rates by comparing the baseline and parametric data. The estimated total PM removal efficiency of the air pollution control (APC) system (ESP) is shown in Table 2-4.

Table 2-3
Total Particulate Matter (TPM) Mass Emission Rates

Unit	Sampling Location	Test date(s):	Test Condition	Sorbent Injection Rate lb/hr	Combined Unit Load MW	Total Particulate Mass Emission Rate lb/hr	Estimated Mass Emission Rate Change from Baseline	
							lb/hr	ton/yr
Units 5 & 6	Stack	6/4-5/10	Baseline	0	355.27	152.9	-	-
Unit 6	ESP Outlet	6/4-5/10	Baseline	0	181.45	81.3		
Unit 6	ESP Outlet	6/7/2010	Trona - Unmilled	9,283	182.21	84.7	3.39	13.55
Unit 6	ESP Outlet	6/8/2010	Trona - Milled	8,696	183.65	168.1	86.77	347.10
Unit 6	ESP Outlet	6/10/2010	Sodium Bicarbonate (SBC)	7,310	182.30	229.0	147.64	590.57
Units 5 & 6	Stack	6/15/2010	Sodium Bicarbonate (SBC)	10,198	357.67	227.7	74.83	299.32

Table 2-4
Total Particulate Matter (TPM) Removal Efficiency

Unit	Sampling Location	Test Condition	Date	Total PM Mass Emission Rate (lb/hr)
Unit 5	ESP Inlet	Baseline	6/4-5/2010	6,822
Unit 6	ESP Inlet	Baseline	6/4-5/2010	6,863
Combined	ESP Inlet	Baseline	6/4-5/2010	13,685
Units 5 & 6	Stack	Baseline	6/4-5/2010	152.87
Removal Eff%		**Baseline**	**6/4-5/2010**	**98.88%**
Unit 6	ESP Inlet	Trona - Unmilled	6/7/2010	15,062
Unit 6	ESP Outlet	Trona - Unmilled	6/7/2010	84.70
Removal Eff%		**Trona - Unmilled**	**6/7/2010**	**99.44%**
Unit 6	ESP Inlet	Trona - Milled	6/8/2010	12,774
Unit 6	ESP Outlet	Trona - Milled	6/8/2010	168.09
Removal Eff%		**Trona - Milled**	**6/8/2010**	**98.68%**
Unit 6	ESP Inlet	SBC	6/10/2010	10,320
Unit 6	ESP Outlet	SBC	6/10/2010	228.96
Removal Eff%		**SBC**	**6/10/2010**	**97.78%**
Unit 5	ESP Inlet	SBC	6/15/2010	10,367
Unit 6	ESP Inlet	SBC	6/15/2010	12,822
Units 5 & 6	Stack	SBC	6/15/2010	227.70
Removal Eff%		**SBC**	**6/15/2010**	**99.02%**

2.3.1 Observations

On June 4, 2010, Shaw conducted a Method 5 train at sample location Unit 6 ESP Inlet and observed an outlier result for Run 2. Based on the reviews, specific actions were taken to remove/modify outlier data points. Specifically, the resulting PM mass emission rate appeared low compared to the other three sample runs. Shaw reviewed all archived samples and data with no observed inconsistencies. Per standard EPA practices, Shaw discarded this data point from the average.

2.4 Speciated Particulate Matter (PM10/PM2.5)

Emissions data for the specific subsets of particulate matter (PM10 and PM2.5) were acquired as noted below. Detailed emissions results are shown in Table 2-5.

The speciated PM for PM10 and PM2.5 was determined using EPA OTM-27. Mass emission rates were calculated in units of *lb/hr* and *lb/MMBtu*. EPA Method 19's published fuel factors for sub-bituminous coal were used in calculating the mass emission rate in *lb/MMBtu*. Based on the calculated emission rates for each type of PM, Shaw estimated the net changes in emission rates by comparing the baseline and parametric data.

Table 2-5
Speciated Particulate Matter (PM10/PM2.5) Mass Emission Rates

Unit #	Sampling Location	Test Condition	Date	Sorbent Injection Rate lb/hr	Unit Load MW	Mass Emission Rate		
						PM >10 lb/hr	PM<10>2.5 lb/hr	PM<2.5 lb/hr
Unit 6	ESP Outlet	Baseline	6/4-5/2010	N/A	181.45	13.48	50.84	17.00
Unit 6	ESP Outlet	Trona - Unmilled	6/7/10	9,283	182.21	5.14	65.93	13.63
Unit 6	ESP Outlet	Trona - Milled	6/8/10	8,696	183.65	9.14	123.10	35.85
Unit 6	ESP Outlet	Sodium Bicarbonate (SBC)	6/10/10	7,310	182.30	8.61	199.66	20.69

Unit #	Sampling Location	Test Condition	Date	Sorbent Injection Rate lb/hr	Combined Unit Load MW	Estimated Mass Emission Rate Change from Baseline		
						PM >10 lb/hr	PM<10>2.5 lb/hr	PM<2.5 lb/hr
Unit 6	ESP Outlet	Baseline	6/4-5/2010	N/A	181.45	-	-	-
Unit 6	ESP Outlet	Trona - Unmilled	6/7/10	9,283	182.21	-8.3	15.1	-3.4
Unit 6	ESP Outlet	Trona - Milled	6/8/10	8,696	183.65	-4.3	72.3	18.9
Unit 6	ESP Outlet	Sodium Bicarbonate (SBC)	6/10/10	7,310	182.30	-4.9	148.8	3.7

Unit #	Sampling Location	Test Condition	Date	Sorbent Injection Rate lb/hr	Combined Unit Load MW	Estimated Mass Emission Rate Change from Baseline		
						PM >10 ton/yr	PM<10>2.5 ton/yr	PM<2.5 ton/yr
Unit 6	ESP Outlet	Baseline	6/4-5/2010	N/A	181.45	-	-	-
Unit 6	ESP Outlet	Trona - Unmilled	6/7/10	9,283	182.21	-33.4	60.4	-13.5
Unit 6	ESP Outlet	Trona - Milled	6/8/10	8,696	183.65	-17.4	289.1	75.4
Unit 6	ESP Outlet	Sodium Bicarbonate (SBC)	6/10/10	7,310	182.30	-19.5	595.3	14.8

2.4.1 Observations

During the performance of particulate testing, the following observations were made by Shaw. Based on the reviews, specific actions were taken to remove/modify outlier data points:

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- During June 4, 2010, OTM-27 train Run 2 at sample location Unit 6 ESP Outlet, the resulting PM mass emission rate appeared significantly higher compared to the other three sample runs. Shaw reviewed all archived samples and data and concluded that possible contamination was picked up from the inside surface of the sample port. Per standard EPA practices, Shaw discarded this data point from the average.
- During June 7, 2010, OTM-27 train Run 3 at sample location Unit 6 ESP Outlet, the resulting PM mass emission rate appeared significantly higher compared to the other three sample runs. Shaw reviewed all archived samples and data and concluded that possible contamination was picked up from the inside surface of the sample port. Per standard EPA practices, Shaw discarded this data point from the average.

2.5 Condensable Particulate Matter (CPM)

Emissions data for condensable particulate matter (CPM) were acquired as noted below. Detailed emissions results are shown in Table 2-6.

The CPM data was determined using EPA Method 202. Mass emission rates were calculated in units of *lb/hr* and *lb/MMBtu*. EPA Method 19 published fuel factors for sub-bituminous coal were used in calculating the mass emission rate in *lb/MMBtu*. Based on the calculated emission rates for CPM, Shaw estimated the net changes in emission rates by comparing the baseline and parametric data.

Table 2-6
Condensable Particulate Matter (CPM) Mass Emission Rates

						Mass Emission Rate		
Unit	**Location**	**Test Condition**	**Test date**	**DSI lb/hr**	**Combined Unit Load MW**	**Total Particulate lb/hr**	**Filterable PM lb/hr**	**CPM lb/hr**
Unit 5 & 6	Stack	Baseline	6/4-5/2010	N/A	354.52	152.87	137.37	15.5
Unit 5 & 6	Stack	SBC	6/15/10	9135	357.67	227.70	155.08	72.62

Unit	Location	Test Condition	Test date	DSI lb/hr	Combined Unit Load MW	Organic Mass % of Total CPM %	Inorganic Mass % of Total CPM %	Filterable PM % of Total Mass Emission Rate %	CPM % of Total Mass Emission Rate %
Units 5 & 6	Stack	Baseline	6/4-5/2010	N/A	354.52	75.3%	24.7%	90.4%	9.6%
Units 5 & 6	Stack	SBC	6/15/10	9135	357.67	57.1%	42.9%	71.7%	28.3%

						Estimated Mass Emission Rate Change from Baseline			
Unit	**Location**	**Test Condition**	**Test date**	**DSI lb/hr**	**Combined Unit Load MW**	**Filterable PM lb/hr**	**CPM lb/hr**	**Filterable PM ton/yr**	**CPM ton/yr**
Units 5 & 6	Stack	Baseline	6/4-5/2010	N/A	354.52	-	-	-	-
Units 5 & 6	Stack	SBC	6/15/10	9135	357.67	17.7	57.1	70.8	228.5

2.5.1 Observations

During the performance of particulate testing on June 4, 2010, Method 5/202 train Run 1 at Unit 5 & 6 stack sample location, Shaw observed that the resulting PM mass emission rate appeared significantly higher compared to the other three sample runs. Shaw reviewed all archived samples and data and concluded that possible organic material contamination. Based on the reviews, specific actions were taken to remove/modify outlier data points.

2.6 Speciated and Total Mercury [HgT, Hg^0, and Hg^{+2}]

Emissions data for speciated and total mercury were acquired as noted below. Detailed emissions results are shown in Tables 2-7 and 2-8.

Emissions of mercury (total and speciated) were determined using ASTM Method D6784-02. Mass emission rates for total mercury (HgT) were calculated in units of *lb/hr* and *lb/TBtu*. In addition to the emission rates, the removal efficiency of the air pollution control system during baseline and parametric testing was also determined.

Table 2-7
Speciated Mercury (Hg0 & Hg^{2+}) and
Total Mercury (HgT) Concentrations and Emission Rate

Unit	Sampling Location	Test Condition	Sorbent Injection Rate (lb/hr)	Unit Load (MW)	Date	Oxidized Mercury - Hg^{2+}			Elemental Mercury – Hg0		
						Conc. at STP, ug/m3	Mass Emission Rate, lb/hr	Conc. at STP, 3%O2, ug/m3	Conc. at STP, ug/m3	Mass Emission Rate, lb/hr	Conc. at STP, 3%O2, ug/m3
Unit 6	ECON Outlet	Baseline	N/A	181.45	6/4-5/10	1.38	0.00140	1.42	6.60	0.00666	6.80
Unit 6	ESP Outlet	Baseline	N/A	181.45	6/4-5/10	0.25	0.00042	0.34	0.81	0.00139	1.14
Units 5 & 6	Stack	Baseline	N/A	355.27	6/4-5/10	0.32	0.00104	0.43	0.69	0.00226	0.93
Unit 6	ECON Outlet	Trona - Unmilled	9,283	182.21	6/7/10	0.09	0.00012	0.09	0.20	0.00025	0.21
Unit 6	ESP Outlet	Trona - Unmilled	9,283	182.21	6/7/10	0.20	0.00031	0.25	1.69	0.00242	2.04
Unit 6	ECON Outlet	Trona - Milled	8,696	183.65	6/8/10	0.08	0.00012	0.08	0.49	0.00053	0.50
Unit 6	ESP Outlet	Trona - Milled	8,696	183.65	6/8/10	0.38	0.00064	0.56	3.25	0.00551	4.77
Unit 6	ECON Outlet	SBC	7,310	182.30	6/10/10	0.27	0.00033	0.28	4.12	0.00502	4.26
Unit 6	ESP Outlet	SBC	7,310	182.30	6/10/10	0.20	0.00033	0.24	2.49	0.00422	3.02
Unit 5	ECON Outlet	SBC	10,198	182.61	6/15/10	0.42	0.00074	0.43	7.55	0.01385	7.79
Unit 6	ECON Outlet	SBC	10,198	182.61	6/15/10	0.75	0.00064	0.77	1.90	0.00251	1.97
Units 5 & 6	Stack	SBC	10,198	357.67	6/15/10	0.07	0.00023	0.09	0.66	0.00211	0.82

Unit	Sampling Location	Test Condition	Sorbent Injection Rate (lb/hr)	Unit Load (MW)	Date	Total Mercury - HgT			Elemental Hg0 Emission Rate (lb/TBtu)	Total HgT Emission Rate (lb/TBtu)
						Conc. at STP, ug/m3	Mass Emission Rate, lb/hr	Conc. at STP, $3\%O_2$, ug/m3		
Unit 6	ECON Outlet	Baseline	N/A	181.45	6/4-5/10	7.98	0.00806	8.21	4.84	5.86
Unit 6	ESP Outlet	Baseline	N/A	181.45	6/4-5/10	1.06	0.00181	1.48	0.81	1.05
Units 5 & 6	Stack	Baseline	N/A	355.27	6/4-5/10	1.01	0.00330	1.36	0.66	0.97
Unit 6	ECON Outlet	Trona - Unmilled	9,283	182.21	6/7/10	0.29	0.00037	0.30	0.16	0.23
Unit 6	ESP Outlet	Trona - Unmilled	9,283	182.21	6/7/10	1.90	0.00273	2.29	1.02	1.16
Unit 6	ECON Outlet	Trona - Milled	8,696	183.65	6/8/10	0.56	0.00066	0.58	0.30	0.37
Unit 6	ESP Outlet	Trona - Milled	8,696	183.65	6/8/10	3.63	0.00615	5.32	3.40	3.80
Unit 6	ECON Outlet	SBC	7,310	182.30	6/10/10	4.39	0.00535	4.53	3.04	3.23

Unit	Sampling Location	Test Condition	Sorbent Injection Rate (lb/hr)	Unit Load (MW)	Date	Total Mercury - HgT			Elemental Hg0 Emission Rate (lb/TBtu)	Total HgT Emission Rate (lb/TBtu)
						Conc. at STP, ug/m3	Mass Emission Rate, lb/hr	Conc. at STP, 3%O_2, ug/m3		
Unit 6	ESP Outlet	SBC	7,310	182.30	6/10/10	2.69	0.00455	3.26	2.16	2.33
Unit 5	ECON Outlet	SBC	10,198	182.61	6/15/10	7.97	0.01459	8.22	5.29	5.57
Unit 6	ECON Outlet	SBC	10,198	182.61	6/15/10	2.65	0.00315	2.74	1.55	1.95
Units 5 & 6	Stack	SBC	10,198	357.67	6/15/10	0.74	0.00235	0.91	0.58	0.65

Table 2-8
Total Mercury (HgT) Removal Efficiency

Unit	Sampling Location	Test Condition	Avg. DSI (lb/hr)	Test Date	Avg. HgT Inlet, lb/hr (coal)	Avg. HgT Mass Emission Rate, lb/hr	System Removal Efficiency %
Units 5 & 6	Common Coal Feed	Baseline	N/A	6/4-5/2010	0.04683		
Unit s5 & 6	Stack	Baseline	N/A	6/4-5/2010		0.00327	**93.0%**
Units 5 & 6	Common Coal Feed	Trona - Unmilled	9,283	6/7/2010	0.04445		
Units 5 & 6	ESP Outlet	Trona - Unmilled	9,283	6/7/2010		0.00545	**87.7%**
Units 5 & 6	Common Coal Feed	Trona - Milled	8,696	6/8/2010	0.07738		
Units 5 & 6	ESP Outlet	Trona - Milled	8,696	6/8/2010		0.01230	**84.1%**
Units 5 & 6	Common Coal Feed	SBC	7,310	6/10/2010	0.06418		
Units 5 & 6	ESP Outlet	SBC	7,310	6/10/2010		0.00909	**85.8%**
Units 5 & 6	Common Coal Feed	SBC	10,198	6/15/2010	0.03721		
Units 5 & 6	Stack	SBC	10,198	6/15/2010		0.00235	**93.7%**

2.6.1 Observations

During the performance of speciated mercury testing, the following observations were made by Shaw. Based on the reviews, specific actions were taken to remove/modify outlier data points:

- During June 8, 2010, OHM train Run 1 at sample location Unit 6 ESP Outlet, the resulting gas stream moisture was observed to be significantly lower compared to the other sample runs. Shaw reviewed all archived samples and data and concluded that limited physical access to the sample point may have resulted in a non-typical sample probe location. Discussions with EEI personnel in conjunction with standard EPA practices resulted in discarding this data point from the average.
- During June 10, 2010, OHM train Run 1 at sample location Unit 6 ECON Outlet, the resulting gas stream moisture was observed to be significantly lower compared to the other sample runs. Shaw reviewed all archived samples and data and concluded that limited physical access to the

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sample point may have resulted in a non-typical sample probe location. Discussions with EEI personnel in conjunction with standard EPA practices resulted in discarding this data point from the average.

- During June 10, 2010 OHM train Run 1 at sample location Unit 6 ESP Outlet, the resulting gas stream moisture was observed to be significantly lower compared to the other sample runs. Shaw reviewed all archived samples and data and concluded that limited physical access to the sample point may have resulted in a non-typical sample probe location. Discussions with EEI personnel in conjunction with standard EPA practices resulted in discarding this data point from the average.

- Shaw performed OHM sampling at the ECON outlet location, but observed that the resulting Hg data was lower than the corresponding ESP outlet or stack data. Shaw concluded that possible interference from the PAC injection system contributed to the low ECON outlet data. Mercury removal efficiencies were calculated using the Hg inlet rate from the coal feed, and the stack or ESP Outlet OHM train measurements.

2.7 Halogens and Hydrogen Halides (Cl_2, HCl, HF)

Emissions data for chlorine, hydrogen chloride, and hydrogen fluoride were acquired as noted below. Detailed emissions results are shown in Table 2-9.

Emissions of chlorine, hydrogen chloride and hydrogen fluoride were determined using EPA Method 26A. Mass emission rates were calculated in units of *lb/hr*, and concentrations are reported in *ppmvd*.

Table 2-9
Halogens and Hydrogen Halides (Cl_2, HCl, HF) Concentration and Mass Emission Rate

			Analytical Data[1]			Concentration In Stack Gas						Mass Emission Rate[2]		
Sampling Date	Test Condition	Sample Location	Cl_2 ug	HCl ug	HF ug	Cl_2 mg/m3	HCl mg/m3	HF mg/m3	Cl_2 ppmv	HCl ppmv	HF ppmv	Cl_2 lb/hr	HCl lb/hr	HF lb/hr
6/4/2010	Baseline	Stack	N/A	660	2000	N/A	0.45	1.35	N/A	0.68	1.12	N/A	1.52	4.60
6/4/2010	Baseline	Stack	N/A	1200	2900	N/A	0.81	1.96	N/A	1.23	1.63	N/A	2.76	6.67
6/5/2010	Baseline	Stack	N/A	1100	3100	N/A	0.74	2.09	N/A	1.13	1.74	N/A	2.53	7.13
6/5/2010	Baseline	Stack	N/A	1100	2800	N/A	0.74	1.89	N/A	1.13	1.57	N/A	2.53	6.44
6/4/2010	Baseline	Stack	<1200	N/A	N/A	<0.810	N/A	N/A	<1.19	N/A	N/A	<2.76	N/A	N/A
6/4/2010	Baseline	Stack	<1200	N/A	N/A	<0.810	N/A	N/A	<1.19	N/A	N/A	<2.76	N/A	N/A
6/5/2010	Baseline	Stack	<1200	N/A	N/A	<0.810	N/A	N/A	<1.19	N/A	N/A	<2.76	N/A	N/A
6/5/2010	Baseline	Stack	<1200	N/A	N/A	<0.810	N/A	N/A	<1.19	N/A	N/A	<2.76	N/A	N/A
6/15/2010	SBC	Stack	N/A	290	730	N/A	0.20	0.49	N/A	0.30	0.41	N/A	0.67	1.68
6/15/2010	SBC	Stack	N/A	<200	460	N/A	<0.13	0.31	N/A	<0.20	0.26	N/A	<0.46	1.06
6/15/2010	SBC	Stack	N/A	<200	410	N/A	<0.13	0.28	N/A	<0.20	0.23	N/A	<0.46	0.94
6/15/2010	SBC	Stack	<1200	N/A	N/A	<0.810	N/A	N/A	<1.19	N/A	N/A	<2.76	N/A	N/A
6/15/2010	SBC	Stack	3100	N/A	N/A	2.092	N/A	N/A	3.08	N/A	N/A	7.13	N/A	N/A
6/15/2010	SBC	Stack	<1200	N/A	N/A	<0.810	N/A	N/A	<1.19	N/A	N/A	<.76	N/A	N/A

Notes:

(1) - Data with a "<" qualifier are reported as below the Reportable Detection Limit (RDL) - Corresponding concentrations and mass emission rates have been calculated using the reported RDL as the minimum mass

(2) - The total mass for each metal is the sum of the front half and back half results. Standard reporting practice for data with a "<" qualifier includes the RDL in the TOTAL sample and qualifying the Total as "<" the reported quantity

(3) - N/A = Not Applicable

(4) - June 4-5, 2010 - Fuel fired was East Thunder (Jacobs Ranch) PRB Coal

(5) - June 15, 2010 - Fuel fired was Belle Ayr PRB Coal

2.8 *Air Toxic Metals*

Emissions data for targeted air toxic metals were acquired as noted below. Detailed emissions results are shown in Table 2-10.

Emissions of the specific air toxic metals were determined using EPA Method 29. Mass emission rates were calculated in units of *lb/hr*, and concentrations are reported in milligrams per cubic meter (mg/m^3).

Table 2-10
Air Toxic Metals Emissions Summary

Analytical Data Results (1) (3)									
Sampling Date		**6/4/2010**	**6/4/2010**	**6/5/2010**	**6/5/2010**	**6/15/2010**	**6/15/2010**	**6/15/2010**	
COC Number		**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	
Test Condition		**Baseline (4)**	**Baseline (4)**	**Baseline (4)**	**Baseline (4)**	**SBC (5)**	**SBC (5)**	**SBC (5)**	
Run #		**M29-1**	**M29-2**	**M29-3**	**M29-4**	**M29-1**	**M29-2**	**M29-3**	**RDL (2)**
Sample Location		**Stack**	**Stack**	**Stack**	**Stack**	**Stack**	**Stack**	**Stack**	
Sample ID	**Units**	**RUN 1-BL-M29**	**RUN 2-BL-M29**	**RUN 3-BL-M29**	**RUN 4-BL-M29**	**RUN 1-SB-M29**	**RUN 2-SB-M29**	**RUN 3-SB-M29**	
Back Half Antimony (Sb)	ug	<1.00	<1.00	<1.00	<1.00	<1.00	<1.00	<1.00	1.0
Front Half Antimony (Sb)	ug	49.90	48.40	<2.00	<2.00	47.90	48.60	49.50	2.00
Total Antimony (Sb)	ug	<50.90	<49.40	<3.00	<3.00	<48.90	<49.60	<50.50	3.00
Back Half Arsenic (As)	ug	<1.00	1.40	<1.00	<1.00	<1.00	<1.00	<1.00	1.0
Front Half Arsenic (As)	ug	1030.00	964.00	<2.00	4.70	968.00	955.00	992.00	2.00
Total Arsenic (As)	ug	<1031.00	965.40	<3.00	<5.70	<969.00	<956.00	<993.00	3.00
Back Half Beryllium (Be)	ug	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	0.25
Front Half Beryllium (Be)	ug	<0.50	0.53	<0.50	<0.50	<0.50	0.56	<0.50	0.50
Total Beryllium (Be)	ug	<0.75	<0.78	<0.75	<0.75	<0.75	<0.81	<0.75	0.75
Back Half Cadmium (Cd)	ug	0.83	1.13	<0.25	0.53	<0.25	<0.25	<0.25	0.25
Front Half Cadmium (Cd)	ug	0.68	<0.50	<0.50	<0.50	<0.50	<0.50	<0.50	0.50
Total Cadmium (Cd)	ug	1.51	<1.63	<0.75	<1.03	<0.75	<0.75	<0.75	0.75
Back Half Chromium (Cr)	ug	1.45	2.49	1.13	1.14	1.88	1.30	1.94	0.75
Front Half Chromium (Cr)	ug	14.70	30.20	16.90	17.50	7.70	7.60	8.20	1.50
Total Chromium (Cr)	ug	16.15	32.69	18.03	18.64	9.58	8.90	10.14	2.25
Back Half Cobalt (Co)	ug	0.77	1.97	0.62	1.19	1.21	0.44	1.53	0.25
Front Half Cobalt (Co)	ug	2.61	2.82	1.01	0.80	1.56	2.06	2.16	0.50
Total Cobalt (Co)	ug	3.38	4.79	1.63	1.99	2.77	2.50	3.69	0.75
Back Half Lead (Pb)	ug	13.80	11.50	3.83	7.65	4.71	3.41	13.90	0.50
Front Half Lead (Pb)	ug	14.90	13.70	2.70	2.50	12.40	13.40	14.10	1.00
Total Lead (Pb)	ug	28.70	25.20	6.53	10.15	17.11	16.81	28.00	1.50

Analytical Data Results (1) (3)

Sampling Date		6/4/2010	6/4/2010	6/5/2010	6/5/2010	6/15/2010	6/15/2010	6/15/2010	
COC Number		N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Test Condition		Baseline (4)	Baseline (4)	Baseline (4)	Baseline (4)	SBC (5)	SBC (5)	SBC (5)	
Run #		M29-1	M29-2	M29-3	M29-4	M29-1	M29-2	M29-3	RDL (2)
Sample Location		Stack	Stack	Stack	Stack	Stack	Stack	Stack	
Sample ID	Units	RUN 1-BL-M29	RUN 2-BL-M29	RUN 3-BL-M29	RUN 4-BL-M29	RUN 1-SB-M29	RUN 2-SB-M29	RUN 3-SB-M29	
Back Half Manganese (Mn)	ug	26.50	33.80	89.90	37.50	9.00	15.40	13.10	1.30
Front Half Manganese (Mn)	ug	61.40	113.00	18.80	14.20	51.20	55.70	58.60	3.80
Total Manganese (Mn)	ug	87.90	146.80	108.70	51.70	60.20	71.10	71.70	5.10
Back Half Nickel (Ni)	ug	2.10	3.70	1.70	1.50	1.50	<1.30	2.10	1.30
Front Half Nickel (Ni)	ug	16.40	71.00	58.70	15.10	5.00	5.00	5.40	2.50
Total Nickel (Ni)	ug	18.50	74.70	60.40	16.60	6.50	<6.30	7.50	3.80
Back Half Selenium (Se)	ug	11.20	15.80	17.70	9.00	3.20	<2.50	<2.50	2.50
Front Half Selenium (Se)	ug	<5.00	<5.00	<5.00	8.20	<5.00	<5.00	5.10	5.0
Total Selenium (Se)	ug	<16.20	<20.80	<22.70	17.20	<8.20	<7.50	<7.60	7.50

Stack Gas Concentration(1)

Sampling Date		6/4/2010	6/4/2010	6/5/2010	6/5/2010	6/15/2010	6/15/2010	6/15/2010
COC Number		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Test Condition		Baseline (4)	Baseline (4)	Baseline (4)	Baseline (4)	SBC (5)	SBC (5)	SBC (5)
Run #		M29-1	M29-2	M29-3	M29-4	M29-1	M29-2	M29-3
Sample Location		Stack	Stack	Stack	Stack	Stack	Stack	Stack
Sample ID	Units	RUN 1-BL-M29	RUN 2-BL-M29	RUN 3-BL-M29	RUN 4-BL-M29	RUN 1-SB-M29	RUN 2-SB-M29	RUN 3-SB-M29
Back Half Antimony (Sb)	mg/m3	<0.0012	<0.0006	<0.0007	<0.0007	<0.0007	<0.0007	<0.0007
Front Half Antimony (Sb)	mg/m3	0.0578	0.0304	<0.0013	<0.0015	0.0328	0.0331	0.0333
Total Antimony (Sb)	mg/m3	<0.0590	<0.0310	<0.0020	<0.0022	<0.0334	<0.0338	<0.0340
Back Half Arsenic (As)	mg/m3	<0.0012	0.0009	<0.0007	<0.0007	<0.0007	<0.0007	<0.0007
Front Half Arsenic (As)	mg/m3	1.1935	0.6052	<0.0013	0.0034	0.6620	0.6505	0.6682
Total Arsenic (As)	mg/m3	<1.1947	0.6061	<0.0020	<0.0041	<0.6626	<0.6512	<0.6689
Back Half Beryllium (Be)	mg/m3	<0.0003	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002
Front Half Beryllium (Be)	mg/m3	<0.0006	0.0003	<0.0003	<0.0004	<0.0003	0.0004	<0.0003
Total Beryllium (Be)	mg/m3	<0.0009	<0.0005	<0.0005	<0.0005	<0.0005	<0.0006	<0.0005
Back Half Cadmium (Cd)	mg/m3	0.0010	0.0007	<0.0002	0.0004	<0.0002	<0.0002	<0.0002
Front Half Cadmium (Cd)	mg/m3	0.0008	<0.0003	<0.0003	<0.0004	<0.0003	<0.0003	<0.0003
Total Cadmium (Cd)	mg/m3	0.0017	<0.0010	<0.0005	<0.0007	<0.0005	<0.0005	<0.0005

Stack Gas Concentration(1)

Sampling Date		6/4/2010	6/4/2010	6/5/2010	6/5/2010	6/15/2010	6/15/2010	6/15/2010
COC Number		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Test Condition		Baseline (4)	Baseline (4)	Baseline (4)	Baseline (4)	SBC (5)	SBC (5)	SBC (5)
Run #		M29-1	M29-2	M29-3	M29-4	M29-1	M29-2	M29-3
Sample Location		Stack	Stack	Stack	Stack	Stack	Stack	Stack
Sample ID	Units	RUN 1-BL-M29	RUN 2-BL-M29	RUN 3-BL-M29	RUN 4-BL-M29	RUN 1-SB-M29	RUN 2-SB-M29	RUN 3-SB-M29
Back Half Chromium (Cr)	mg/m3	0.0017	0.0016	0.0007	0.0008	0.0013	0.0009	0.0013
Front Half Chromium (Cr)	mg/m3	0.0170	0.0190	0.0112	0.0127	0.0053	0.0052	0.0055
Total Chromium (Cr)	mg/m3	0.0187	0.0205	0.0120	0.0135	0.0066	0.0061	0.0068
Back Half Cobalt (Co)	mg/m3	0.0009	0.0012	0.0004	0.0009	0.0008	0.0003	0.0010
Front Half Cobalt (Co)	mg/m3	0.0030	0.0018	0.0007	0.0006	0.0011	0.0014	0.0015
Total Cobalt (Co)	mg/m3	0.0039	0.0030	0.0011	0.0014	0.0019	0.0017	0.0025
Back Half Lead (Pb)	mg/m3	0.0160	0.0072	0.0025	0.0056	0.0032	0.0023	0.0094
Front Half Lead (Pb)	mg/m3	0.0173	0.0086	0.0018	0.0018	0.0085	0.0091	0.0095
Total Lead (Pb)	mg/m3	0.0333	0.0158	0.0043	0.0074	0.0117	0.0115	0.0189
Back Half Manganese (Mn)	mg/m3	0.0307	0.0212	0.0596	0.0272	0.0062	0.0105	0.0088
Front Half Manganese (Mn)	mg/m3	0.0711	0.0709	0.0125	0.0103	0.0350	0.0379	0.0395
Total Manganese (Mn)	mg/m3	0.1019	0.0922	0.0721	0.0375	0.0412	0.0484	0.0483
Back Half Nickel (Ni)	mg/m3	0.0024	0.0023	0.0011	0.0011	0.0010	<0.0009	0.0014
Front Half Nickel (Ni)	mg/m3	0.0190	0.0446	0.0389	0.0110	0.0034	0.0034	0.0036
Total Nickel (Ni)	mg/m3	0.0214	0.0469	0.0401	0.0121	0.0044	<0.0043	0.0051
Back Half Selenium (Se)	mg/m3	0.0130	0.0099	0.0117	0.0065	0.0022	<0.0017	<0.0017
Front Half Selenium (Se)	mg/m3	<0.0058	<0.0031	<0.0033	0.0060	<0.0034	<0.0034	0.0034
Total Selenium (Se)	mg/m3	<0.0188	<0.0131	<0.0151	0.0125	<0.0056	<0.0051	<0.0051

Mass Emission Rate(1)

Sampling Date		6/4/2010	6/4/2010	6/5/2010	6/5/2010	6/15/2010	6/15/2010	6/15/2010
COC Number		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Test Condition		Baseline (4)	Baseline (4)	Baseline (4)	Baseline (4)	SBC (5)	SBC (5)	SBC (5)
Run #		M29-1	M29-2	M29-3	M29-4	M29-1	M29-2	M29-3
Sample Location		Stack	Stack	Stack	Stack	Stack	Stack	Stack
Sample ID	Units	RUN 1-BL-M29	RUN 2-BL-M29	RUN 3-BL-M29	RUN 4-BL-M29	RUN 1-SB-M29	RUN 2-SB-M29	RUN 3-SB-M29
Back Half Antimony (Sb)	lb/hr	<0.0040	<0.0021	<0.0021	<0.0024	<0.0022	<0.0022	<0.0022
Front Half Antimony (Sb)	lb/hr	0.1981	0.1021	<0.0042	<0.0048	0.1066	0.1051	0.1076
Total Antimony (Sb)	lb/hr	<0.2021	<0.1042	<0.0063	<0.0072	<0.1088	<0.1072	<0.1098
Back Half Arsenic (As)	lb/hr	<0.0040	0.0030	<0.0021	<0.0024	<0.0022	<0.0022	<0.0022
Front Half Arsenic (As)	lb/hr	4.0891	2.0329	<0.0042	0.0113	2.1538	2.0646	2.1571
Total Arsenic (As)	lb/hr	<4.0931	2.0358	<0.0063	<0.0137	<2.1560	<2.0668	<2.1593
Back Half Beryllium	lb/hr	<0.0010	<0.0005	<0.0005	<0.0006	<0.0006	<0.0005	<0.0005

Mass Emission Rate(1)

Sampling Date		6/4/2010	6/4/2010	6/5/2010	6/5/2010	6/15/2010	6/15/2010	6/15/2010
COC Number		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Test Condition		Baseline (4)	Baseline (4)	Baseline (4)	Baseline (4)	SBC (5)	SBC (5)	SBC (5)
Run #		M29-1	M29-2	M29-3	M29-4	M29-1	M29-2	M29-3
Sample Location		Stack	Stack	Stack	Stack	Stack	Stack	Stack
Sample ID	Units	RUN 1-BL-M29	RUN 2-BL-M29	RUN 3-BL-M29	RUN 4-BL-M29	RUN 1-SB-M29	RUN 2-SB-M29	RUN 3-SB-M29
(Be)								
Front Half Beryllium (Be)	lb/hr	<0.0020	0.0011	<0.0010	<0.0012	<0.0011	0.0012	<0.0011
Total Beryllium (Be)	lb/hr	<0.0030	<0.0016	<0.0016	<0.0018	<0.0017	<0.0018	<0.0016
Back Half Cadmium (Cd)	lb/hr	0.0033	0.0024	<0.0005	0.0013	<0.0006	<0.0005	<0.0005
Front Half Cadmium (Cd)	lb/hr	0.0027	<0.0011	<0.0010	<0.0012	<0.0011	<0.0011	<0.0011
Total Cadmium (Cd)	lb/hr	0.0060	<0.0034	<0.0016	<0.0025	<0.0017	<0.0016	<0.0016
Back Half Chromium (Cr)	lb/hr	0.0058	0.0053	0.0024	0.0027	0.0042	0.0028	0.0042
Front Half Chromium (Cr)	lb/hr	0.0584	0.0637	0.0354	0.0422	0.0171	0.0164	0.0178
Total Chromium (Cr)	lb/hr	0.0641	0.0689	0.0378	0.0449	0.0213	0.0192	0.0220
Back Half Cobalt (Co)	lb/hr	0.0031	0.0042	0.0013	0.0029	0.0027	0.0010	0.0033
Front Half Cobalt (Co)	lb/hr	0.0104	0.0059	0.0021	0.0019	0.0035	0.0045	0.0047
Total Cobalt (Co)	lb/hr	0.0134	0.0101	0.0034	0.0048	0.0062	0.0054	0.0080
Back Half Lead (Pb)	lb/hr	0.0548	0.0243	0.0080	0.0184	0.0105	0.0074	0.0302
Front Half Lead (Pb)	lb/hr	0.0592	0.0289	0.0057	0.0060	0.0276	0.0290	0.0307
Total Lead (Pb)	lb/hr	0.1139	0.0531	0.0137	0.0245	0.0381	0.0363	0.0609
Back Half Manganese (Mn)	lb/hr	0.1052	0.0713	0.1884	0.0904	0.0200	0.0333	0.0285
Front Half Manganese (Mn)	lb/hr	0.2438	0.2383	0.0394	0.0342	0.1139	0.1204	0.1274
Total Manganese (Mn)	lb/hr	0.3490	0.3096	0.2278	0.1246	0.1339	0.1537	0.1559
Back Half Nickel (Ni)	lb/hr	0.0083	0.0078	0.0036	0.0036	0.0033	<0.0028	0.0046
Front Half Nickel (Ni)	lb/hr	0.0651	0.1497	0.1230	0.0364	0.0111	0.0108	0.0117
Total Nickel (Ni)	lb/hr	0.0734	0.1575	0.1266	0.0400	0.0145	<0.0136	0.0163
Back Half Selenium (Se)	lb/hr	0.0445	0.0333	0.0371	0.0217	0.0071	<0.0054	<0.0054
Front Half Selenium (Se)	lb/hr	<0.0199	<0.0105	<0.0105	0.0198	<0.0111	<0.0108	0.0111
Total Selenium (Se)	lb/hr	<0.0643	<0.0439	<0.0476	0.0415	<0.0182	<0.0162	<0.0165

Notes:
(1) - Data with a "<" qualifier are reported as below the Reportable Detection Limit (RDL) - Corresponding concentrations and mass emission rates have been calculated using the reported RDL as the minimum mass
(2) - The RDL for the Front Half (nozzle/probe/filter) and Back Half (back of filter housing/all impingers) varies for each metal.
(3) - The total mass for each metal is the sum of the front half and back half results. Standard reporting practice for data with a "<" qualifier includes the RDL in the TOTAL sample and qualifying the Total as "<" the reported quantity
(4) - June 4-5, 2010 - Fuel fired was East Thunder (Jacobs Ranch) PRB Coal
(5) - June 15, 2010 - Fuel fired was Belle Ayr PRB Coal

2.9 Sulfur Trioxide (SO_3)

Emissions data for SO_3 was acquired as noted below. Detailed emissions results are shown in Table 2-11. Emissions of the specific air toxic metals were determined using NCASI Method 8A. Mass emission rates were calculated in units of *lb/hr*, and concentrations are reported in milligrams per cubic meter (mg/m^3).

Table 2-11
SO3 Emissions Summary

				Sulfate Concentration					Gas Meter Volume, V_{mstd}		SO_3 Stack Concentration	
Run #	Date	Location	Condition	Sample ID	mg/L	Sample Vol. ml	Mass mg	Total Mass mg	ft^3	m3	mg/m3	ppmvd
1	6/4/10	Stack	Baseline	1C-Cond.	8.3	250	2.075	2.45	8.497	0.2406	10.2	3.1
1	6/4/10	Stack	Baseline	1I – IPA Impinger	1.5	250	0.375		8.497	0.2406		
2	6/4/10	Stack	Baseline	2C-Cond.	2.6	250	0.65	134.9	8.657	0.2452	550.2	165.3
2	6/4/10	Stack	Baseline	2I - IPA Impinger	537	250	134.25		8.657	0.2452		
3	6/5/10	Stack	Baseline	3C-Cond.	2.3	250	0.575	516.8	8.51	0.2410	2144.4	644.4
3	6/5/10	Stack	Baseline	3I - IPA Impinger	2065	250	516.25		8.51	0.2410		
4	6/5/10	Stack	Baseline	4C-Cond.	6.1	250	1.525	114.3	8.518	0.2412	473.7	142.3
4	6/5/10	Stack	Baseline	4I - IPA Impinger	451	250	112.75		8.518	0.2412		

2.9.1 Observations

Shaw performed SO_3 sampling at the common stack during the baseline condition only. Shaw laboratory personnel performed onsite titrations of the samples in accordance with the procedures in the reference test method. Shaw personnel noted that starting with the second test run, the titration procedures did not reach the reference endpoint for comparative data and the results in the field were inconsistent.

The samples were archived and submitted to the Shaw TDL laboratory upon return to the Knoxville office. The laboratory performed ion chromatography (IC) analysis, with the results as shown in Table 2-11. Shaw's review of the data shows that extremely high sulfite concentrations were observed from the condenser catch samples for Run 2 through Run 4. The sulfite concentrations appeared to be outside the normal range for coal fired boiler operations and inconsistent with known regulatory data.

Shaw did not observe any physical irregularities in the samples. Therefore, Shaw recommends that these runs be discarded from consideration.

2.10 Mercury Material Balance

A material balance across the Unit 5 and 6 was estimated as shown in Table 2-12. The material balance was calculated using the coal fuel analyses (ultimate, proximate, and mercury mass) in conjunction with OHM sample train data acquired at either the stack or Unit 6 ESP outlet. The fly ash data was determined by Shaw's TDL laboratory, but was limited to baseline and SBC injection testing days. For the mercury mass in fly ash during Trona injection, Shaw used the average of the baseline and SBC analytical data to perform the material balance calculations on June 7-8, 2010. The estimated coal feed properties are shown in Table 2-13.

Table 2-12
Estimated Total Mercury (HgT) Material Balance

Coal Sample Date	Condition	Hg In (coal)	Hg Out (fly ash)	Hg Out (Stack)	Total Hg Out	Net Hg Accounted For By Fd
		gm/hr	gm/hr	gm/hr (Fd)	gm/hr (Fd)	% of Hg In
6/4/2010	Baseline	21.71	12.22	1.56	13.78	63%
6/5/2010	Baseline	20.77	10.87	1.46	12.33	59%
6/7/2010(1)	Trona-Unmilled	20.16	14.19	2.87	17.07	85%
6/8/2010(1)	Trona-Milled	35.10	13.86	5.59	19.45	55%
6/10/2010	SBC	29.11	15.32	4.12	19.44	67%
6/15/2010	SBC	16.88	11.52	1.07	12.59	75%

Notes:
(1) – Fly ash mercury data determined by average of baseline and SBC analytical data

Table 2-13
Coal Feed Properties

Coal Sample Date	Condition	GCV	Ash	Moist.	Coal Hg	Fly Ash Hg	Coal Feed Rate	
		Btu/lb	%-dry	%	(ppmw)	(ppbw)	(lb/hr)	ton/hr
6/4/2010	Baseline	8,420	7.95	26.40	0.098	943	359,396	180
6/5/2010	Baseline	8,370	7.54	27.10	0.099	943	337,105	169
6/7/2010(1)	Trona-Unmilled	8,630	7.77	26.60	0.081	***1000***	402,716	201
6/8/2010(1)	Trona-Milled	7,840	7.72	33.00	0.131	***1000***	395,801	198
6/9/2010(1)	Trona-Milled - CEMS only	8,390	8.32	27.90	0.103	***1000***	380,580	190
6/10/2010	SBC	8,470	7.80	27.80	0.113	1056	410,037	205
6/11/2010	SBC - CEMS only	8,430	8.02	27.80	0.164	1056	374,687	187
6/14/2010	SBC - CEMS only	8,350	7.16	28.60	0.083	1056	377,582	189
6/15/2010	SBC	8,510	6.41	28.40	0.071	1056	375,298	188

Notes:
(1) – Fly ash mercury data determined by average of baseline and SBC analytical data

The fly ash data was determined by Shaw's TDL laboratory, but was limited to baseline and SBC injection testing days. For the mercury mass in fly ash during Trona injection, Shaw used the average of the baseline and SBC analytical data to perform the material balance calculations on June 7-8, 2010.

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Appendix A
Sampling Methodologies

Sampling Methodologies

Test Methods Used

Location of Traverse Points

To ensure representative measurement of gas velocity and volumetric flow rates, the cross section of the gas ducts and stack were divided into discrete sampling points according to the procedures described in 40 CFR 60, Appendix A, Method 1. The stack gas characteristics (i.e., velocity pressures and temperature) were measured at each of the traverse locations during each test run.

Velocity and Volumetric Flow Measurement

Velocity measurements were performed during each test run at each traverse point to characterize the gas stream velocities and flow characteristics using the procedures outlined in 40 CFR 60, Appendix A, Method 2. Velocity pressures were measured using an "S"-type or standard Pitot tube and standard oil filled manometers. Data was recorded for each traverse point location.

Temperature Measurement

The temperature of the stack gas was recorded at each sample traverse point using K-type thermocouples and dedicated digital temperature readouts. Temperatures were recorded on the sampling data sheet for each traverse point location. Gas duct and stack temperatures were arithmetically averaged and used to calculate the volumetric flow rates at standard and dry standard conditions.

Moisture Determination

The moisture content of the stack gas was determined using procedures outlined in 40 CFR 60, Appendix A, Method 4. Method 4 sampling was incorporated into each sampling train. The moisture weight gain of the chilled impingers was determined gravimetrically for each sampling train.

Carbon Dioxide (CO_2) Determination (Instrumental Method)

The CO_2 concentrations were sampled and determined using a dedicated non-dispersive infrared (NDIR) analyzer. The CO_2 sampling conformed to procedures presented in 40 CFR 60, Appendix A, Method 3A. The CO_2 monitor was calibrated using EPA Protocol gases prior to and after the completion of the test run series. Zero and mid/high point calibration bias checks were performed prior to the beginning and at the completion of each test run to ensure the integrity of the sampling train system. The concentration of CO_2 is reported in percentage of carbon dioxide (% CO_2) by volume on a dry basis.

Access to the gas stream was through a shared sample line. A heated and filtered stainless steel probe was used to extract the gas sample from the ducts. A heated, 3/8" Teflon® line transported the sample from the point of extraction to the non-contact gas conditioning chiller system. The moisture was condensed and removed from the gas stream, while the pollutant passed through to the analytical equipment. The analyzer was located in a temperature-controlled area to minimize thermal affects on the calibration of the instrument.

Oxygen (O_2) Determination (Instrumental Method)

The O_2 concentrations were sampled and determined using a paramagnetic O_2 analyzer. The O_2 sampling conformed to procedures presented in 40 CFR 60, Appendix A, Method 3A. The O_2 monitor was calibrated using EPA Protocol gases prior to and after the completion of the test run series. Zero and mid/high point calibration bias checks were performed prior to the beginning and at the completion of each test run to ensure the integrity of the sampling train system. The concentration of O_2 is reported in percentage of oxygen (% O_2) by volume on a dry basis.

Access to the gas stream was through a shared sample line. A heated and filtered stainless steel probe was used to extract the gas sample from the ducts. A heated, 3/8" Teflon® line transported the sample from the point of extraction to the non-contact gas conditioning chiller system. The moisture was condensed and removed from the gas stream, while the pollutant passed through to the analytical equipment. The analyzer was located in a temperature-controlled area to minimize thermal affects on the calibration of the instrument.

Sulfur Dioxide (SO_2) Determination

The gas stream was sampled separately for sulfur dioxide (SO_2) concentration using an ultraviolet SO_2 gas analyzer. SO_2 sampling conformed to procedures presented in 40 CFR 60, Appendix A, Method 6C. Access to the stack was through a shared sample line. A heated and filtered stainless steel probe was used to extract the gas sample from the gas ducts at the required traverse points in accordance with 40 CFR 60, Appendix B, Performance Specification 2. A heated, 3/8" Teflon® line transported the sample from the point of extraction to the non-contact gas conditioning chiller system. The moisture was condensed and removed from the gas stream, while the pollutant passed through to the analytical equipment. The analyzer was located in a temperature-controlled area to minimize thermal affects on the calibration of the instrument.

The concentration and mass emissions of SO_2 in the gas stream are reported in the units of the appropriate standard. Concentrations were recorded in parts per million by volume (ppmv) on a dry basis. The emission rate was calculated using the specific run-time average concentration in ppmv, the dry standard volumetric flow rate, the Ideal Gas Law, and the sampling time.

Nitrogen Oxides (NO_X) Determination

NO_X sampling conformed to procedures presented in 40 CFR 60, Appendix A, Method 7E. Access to the gas stream was through a shared sample line. A heated and filtered stainless steel probe was used to extract the gas sample from the gas ducts. A heated, 3/8" Teflon® line transported the sample from the point of extraction to the non-contact gas conditioning chiller system. The moisture was condensed and removed from the gas stream, while the pollutant passes through to the analytical equipment. The analyzer was located in a temperature-controlled area to minimize thermal affects on the calibration of the instrument.

The stack gases were sampled separately for oxides of nitrogen (NO_x) concentrations using a chemiluminescent NO-NO_x gas analyzer. The chemiluminescent reaction of NO and ozone (O_3) takes place as follows:

$$NO + O_3 \rightarrow NO_2 + O_2 + h_\upsilon$$
$$\text{where } h_\upsilon = \text{light}$$

As the electronically excited NO_2 molecules revert to their ground state, a photon particle (as light) is emitted. The NO gas sample concentration is blended with O_3 in a reaction chamber. The resulting photon emission (chemiluminescence) is detected by in the optical filter by a high-sensitivity photomultiplier detector located at the end of the reaction chamber. The detector responds to light in a narrow-wavelength band unique to the above reaction. The output from the photomultiplier is linearly proportional to the NO concentration.

To measure the total NO_X concentrations as NO_2 (i.e., NO plus NO_2), the sample gas flow passes through an NO_2-to-NO converter. The detector response in the reaction chamber to the converted effluent is linearly proportional to the NO_X concentration entering the converter. The instrument is operated in the NO_X mode during all test and calibration and all results are reported as NO_2.

The concentration and mass emissions of NO_x in the gas stream are reported in the units of the appropriate standard. Concentrations were recorded in parts per million by volume (ppmv) on a dry basis. The emission rate was calculated using the specific run time average concentration in ppmv, the dry standard volumetric flow rate, the Ideal Gas Law, and the sampling time.

Sulfur Compound Sampling Procedures (Method 8A)

The gas stream was sampled for sulfur trioxide (SO_3) using an NCASI Method 8A sampling train. The sampling train collected approximately 30 cubic feet of gas during each sampling run. The sampling train used in this method is similar to the EPA Method 8, with several exceptions accounted for in the sample filtration method and the impinger reagents. The sampling train impingers were preceded by a heated sampling probe, a heated quartz filter holder, and a heated H_2SO_4 condenser.

The probe liner was constructed of quartz, which was heated using a controlled heating element to maintain the gas stream above the acid dew point, and encased in a 304 stainless steel jacket. The sample probe was connected directly to a insulated sulfuric acid sampling box that contained a quartz filter holder and a 37-mm diameter quartz filter. The filter holder was maintained at temperatures greater than 500°F by a cylindrical heating mantle.

The filter holder was then directly attached to the H_2SO_4 condenser. The condenser was a Modified Graham condenser, with a Type C glass frit and 200 cm of 5-mm ID glass tubing for condenser coil. The condenser was filled with water and maintained at a temperature between 167 and 185°F with a cylindrical heating mantle.

The condenser was attached to the four reagent impingers. The first two impingers contained approximately 100 ml of a 3% peroxide solution to facilitate capture and retention of the SO_3. The third impinger contained approximately 100 ml of distilled DI water. The fourth impinger contained approximately 200 g of indicating silica gel as a final moisture trap.

At the completion of each sample run the probe was disconnected from the sample train. Clean dry ambient air was pulled through the train for 15 minutes. After the purge was completed the sample train was recovered as follows:

> **Container 1 –** The probe, quartz filter holder and the H2SO4 condenser were rinsed separately with deionized water using multiple rinse techniques described in Method 8A. The rinsate was collected in a clean sample jar, sealed with a Teflon lined lid, and sealed with Teflon tape. The sample was labeled and transferred to the onsite sample chemist for analysis per Method 8A.
>
> **Container 2 –** The impingers were externally dried and gravimetrically weighed to determine the moisture gain. The reagents in impingers one and two were volumetrically measured. The reagents were collected in a clean sample jar, sealed with a Teflon lined lid, and sealed with Teflon tape. The sample was labeled and transferred to the onsite sample chemist for analysis per Method 8A.

Reagent blanks of the peroxide solution were collected and analyzed per Method 8A.

Particulate Matter Sampling Procedure

The sampling for PM was performed using the sampling procedures described in 40 CFR 60, Appendix A, Methods 5. To measure the particulate emission rates, a slipstream was withdrawn isokinetically from the stack. Particulate matter was collected on a heated filter, and the stack gas moisture was collected in a series of chilled impingers containing water and silica gel to facilitate capture of the gas stream moisture.

The equipment used to perform the sampling has the approval, and meets the standards, of calibration accuracy as set forth by U.S. EPA. Copies of the calibrations are appended to this document.

The sampling equipment consisted of three main units: the pump, control units, and sampling train. The pump was a lubricated fiber vane rotary pump altered for leak-free operation. The pump was connected to the control unit that contained a calibrated dry gas meter, dual incline manometers, and a calibrated orifice system designed to enable isokinetic sampling. The sampling train was connected to the control console by means of a flexible umbilical cord. The sampling train contained the impinger case, filter oven and probe.

The nozzle was constructed of stainless steel and connected to the end of the probe with a stainless steel union. The probe was constructed with glass wrapped with a heating element and encased in a 304 stainless steel tube. The heating element maintained the gas sample temperature inside the probe above the gaseous dew point preventing condensation of moisture in the probe. The probe was rigidly mounted to the filter heater box and directly connected to a heated glass filter holder that contained a pre-weighed glass fiber filter supported with a Teflon® frit. The filter oven temperature was maintained between 225 and 275 °F during the tests.

The filter holder was connected directly to the impinger train that contained a series of four ball top impingers in an ice bath. The impinger train was prepared by placing 100 ml of distilled water in each of the first and second impingers. The third impinger was initially empty. The fourth impinger contained approximately 200 grams of indicating silica gel as a final moisture trap. The impinger train was assembled in a dedicated clean area prior to being taken to the stack where the probe and filter were attached to the train.

The stack sample was drawn isokinetically through the nozzle, the heated probe and into the heated filter assembly, where the particulate matter was collected on the pre-weighed filter. The gas sample stream then passed through the impinger train, which condensed the moisture from the sample stream. The gas then passed through the umbilical cord to the dry gas meter, orifice and pump.

The gas stream velocity and temperature were monitored at each sampling point to insure that isokinetic sampling rates was being maintained. Leak checks were performed on the sampling train to insure the integrity of the sample collected prior to beginning the test and again at the conclusion of the test.

At the conclusion of each particulate test, a recovery was conducted on the sampling train. The recovery procedure was as follows:

Probe Wash – The nozzle, probe and front half of the filter holder were rinsed and brushed six times with acetone into a leak-free jar. The rinsate was subsequently placed into a pre-weighed container and evaporated to dryness. The container was then desiccated and weighed to a constant weight to the nearest 0.1 mg.

Impingers – Each impinger was weighed separately to the nearest milligram to determine the moisture gain for the test. The contents and rinsate from these impingers were used in the analysis of CPM determination.

Particulate Filter – The particulate filter was removed from the glass filter holder and placed back into its original glass petri dish, then sealed with Teflon® tape. The filter was later placed into a desiccator and dried for 24 hours. The filter was then weighed to a constant weight to the nearest 0.1 mg.

Blank Reagents – A sample of the acetone used in the train clean up was collected as a reagent blank. The blank was analyzed in the same manner as the other wash samples.

Condensable Particulate Matter Determination (Method 202)

The CPM was collected in the impinger portion of Method 5 (Appendix A, 40 CFR 60) type sampling train. The impinger contents were immediately purged after the run with nitrogen (N_2) to remove dissolved sulfur dioxide (SO_2) gases from the impinger contents. The impinger solution was then extracted with methylene chloride. The organic and aqueous fractions were taken to dryness and the residues weighed. The total of both fractions represented the CPM.

All sample recovery was performed at the test site laboratory by the test crew. All final particulate sample analyses were performed by the test team in accordance to USEPA Method 202, 40 CFR 51, Appendix M. Copies of all sample analysis sheets, explanations of nomenclature and calculations, and raw field data sheets are appended to this document.

PM10 and PM2.5 Sampling Procedures

The sampling for PM10 and PM2.5 was performed using the sampling procedures described in USEPA OTM 27. To measure the particulate emission rates, a slipstream was withdrawn at a constant rate from the stack. Filterable particulate matter was collected in-stack with PM10 and PM2.5 cyclone heads, and the stack gas moisture was collected in a series of chilled impingers containing water and silica gel to facilitate capture of the gas stream moisture.

The sampling equipment consisted of three main units: the pump, control units, and sampling train. The pump was a lubricated fiber vane rotary pump altered for leak-free operation. The pump was connected to the control unit that contained a calibrated dry gas meter, dual incline manometers, and a calibrated orifice system. The sampling train was connected to the control console by means of a flexible umbilical cord. The sampling train contained the impinger case, filter oven, probe and cyclones.

The impinger train was prepared by placing 100 ml of distilled water in each of the first and second impingers. The third impinger was initially empty. The fourth impinger contained approximately 200 grams of indicating silica gel as a final moisture trap. The impinger train, along with the cyclones were assembled in a dedicated clean area prior to being taken to the stack where they were connected to the probe.

The stack sample was drawn at a constant rate through a stainless steel nozzle and PM10 cyclone head, which collected PM greater than 10 microns. The gas sample then passed through a stainless steel PM2.5 cyclone, which collected PM less than 10 microns and greater than 2.5 microns. Upon exiting the PM2.5 cyclone, the gas sample was drawn through an in-line quartz filter, which collected PM less than 2.5 microns. The gas sample stream then passed through the impinger train, which condensed the moisture from the sample stream. The gas then passed through the umbilical cord to the dry gas meter, orifice and pump.

The gas stream velocity and temperature were monitored at each sampling point. Leak checks were performed on the sampling train to insure the integrity of the sample collected prior to beginning the test and again at the conclusion of the test.

At the conclusion of each particulate test, a recovery was conducted on the sampling train. The recovery procedure was as follows:

> **Particulate Filter –** The particulate filter was removed from the filter holder and placed back into its original glass petri dish, then sealed with Teflon® tape. The filter was later placed into a desiccator and dried for 24 hours. The filter was then weighed to a constant weight to the nearest 0.1 mg.

PM10 Cyclone – The particulate matter from the PM10 cyclone cup was removed and placed in a dedicated container. The nozzle, cyclone cup, and cyclone internal surfaces were then rinsed and brushed with acetone into the dedicated container and sealed. The rinsate was subsequently placed into a pre-weighed container and evaporated to dryness. The container was then desiccated and weighed to a constant weight to the nearest 0.1 mg.

PM2.5 Cyclone – The particulate matter from the PM2.5 cyclone cup was removed and placed in a dedicated container. The cyclone turnaround cup, inside of the downcomer line, and cyclone internal surfaces were then rinsed and brushed with acetone into the dedicated container and sealed. The rinsate was subsequently placed into a pre-weighed container and evaporated to dryness. The container was then desiccated and weighed to a constant weight to the nearest 0.1 mg.

Particulate Filter Holder – The exit of the tube of the PM2.5 cyclone and the front half of the filter holder where rinsed and brushed with acetone into a dedicated container and sealed. The rinsate was subsequently placed into a pre-weighed container and evaporated to dryness. The container was then desiccated and weighed to a constant weight to the nearest 0.1 mg.

Impingers – Each impinger was weighed separately to the nearest milligram to determine the moisture gain for the test. The contents from these impingers were discarded at the conclusion of the recovery process.

Blank Reagents – A sample of the acetone used in the train clean up was collected as a reagent blank. The blank was analyzed in the same manner as the other wash samples.

HF, HCl, and Cl_2 Sampling Procedures

The HF, HCl and Cl_2 sampling was performed using the sampling procedures described in 40 CFR 60, Method 26A. The equipment has the approval, and meets the standards, of calibration accuracy as set forth by U.S. EPA. The sampling equipment consisted of three main units: the pump, control units, and sampling train. The pump was a Teflon® coated rotary pump connected to the control unit that contained a calibrated dry gas meter, heat controllers and sampling rate flow controllers. The sampling train, which contained the impinger case, filter oven and probe, was connected to the control console by means of a flexible umbilical cord.

The probe was constructed with a glass tube wrapped with a heating element encased in a 304 stainless steel tube. The heating element maintained the gas sample temperature inside the probe above the gaseous dew point preventing condensation of moisture in the probe. The probe was rigidly mounted to the impinger box and directly connected to a heated Teflon® filter holder, which contained a quartz filter. The filter oven temperature was maintained between 225 and 275 ^{o}F during the tests.

The impinger train was prepared by leaving the first impinger empty and placing 100 ml of 0.1N sulfuric acid into the second and third impingers. The fourth and fifth impingers contained 100 ml of sodium hydroxide. Impinger six contained indicating silica gel as a final moisture trap. All fittings were ground glass to glass with Viton o-rings to prevent leakage. At the beginning and end of each test run a leak check was performed on the entire test train to insure the integrity of the sample collected.

At the conclusion of each test, a recover was conducted on the sampling train. The recover procedure was as follows:

Impingers - The impinger train were weighed separately to the nearest milligram to determine the moisture gain for the test. The contents of impingers one through three were transferred into a glass storage container and rinsed with DI water. The rinse was added into the sample container. The contents of impingers four and five were transferred into a sample container rinsed with DI water. The rinse was added into the sample container. The silica gel impinger was weighed for moisture gain determination and the contents were then discarded.

Blank reagents - A sample of the sulfuric acid and sodium hydroxide absorbing solutions used in the impingers were collected and analyzed in the same manner as the actual stack samples.

At the conclusion of the fieldwork, the samples were delivered to an offsite laboratory for subsequent analysis.

Multi-Metals Sampling Procedures

During the test, the stack emissions were sampled and analyzed for the multiply metals. The sampling procedures implemented followed 40 CFR 60, Appendix A, Method 29.

The sampling train was based on the standard EPA Method 5 configuration with modifications to the sampling reagents placed in the impingers and the use of a glass nozzle. The stack gas was isokinetically extracted from the stack and pulled through a heated probe and filter assembly. The filtered gas passed through the impinger train consisting of four impingers. The first and second impingers each contained a 100 ml mixture of 5% HNO_3 and 10% H_2O_2 solution. The third impinger remained empty as a moisture knockout. The fourth impinger contained 200 grams of indicating silica gel. The impinger section of the train was assembled in a dedicated clean area prior to being taken to the stack where the filter and probe were attached to the trains. All fittings were ground glass to glass to prevent leakage. Leak checks were performed on the sampling train at the beginning and end of each test run.

At the conclusion of each MMT test, the probe and filter holder were removed and sealed with Teflon® tape. The test train components were returned to the clean room for disassembly. The clean-up procedures were as follows:

Probe Wash – The nozzle, probe and front half of the filter holder were rinsed and brushed three times with acetone, then rinsed with 0.1N HNO_3 into a leak-free jar. The rinsates were subsequently placed into sample collection jars.

Impingers – each impinger was weighed separately to the nearest 0.1 gram to determine the moisture gain for the test. The liquid contents of the impingers were transferred to separate sample containers, labeled and logged into the sample collection records. After transferring the contents of each impinger, they were rinsed along with all connecting glassware with 0.1N nitric acid. The rinsate was collected into a separate sample container.

Particulate Filter – The particulate filter was removed from the glass filter holder and placed back into its original glass petri dish, then sealed with Teflon® tape.

Blank reagents – Samples of the impinger reagents and cleaning solutions used in the MMT train were collected as reagent blanks for the performance test runs.

Total Mercury, Elemental Mercury, Oxidized Mercury Sampling Procedures

Sampling for elemental mercury Hg^0, oxidized mercury Hg^{2+} and total mercury was performed in accordance with the “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (The Ontario Hydro Method)”, ASTM D6784-02. This method is applicable to the determination of elemental mercury Hg^0, oxidized mercury Hg^{2+}, and total mercury emissions from stationary sources.

The probe was constructed with a glass tube wrapped with a heating element encased in a 304 stainless steel tube. The heating element maintained the gas sample temperature inside the probe above the gaseous dew point preventing condensation of moisture in the probe. The probe was rigidly mounted to the impinger box and directly connected to a heated Teflon® filter holder, which contained a quartz filter. The filter oven temperature was maintained between 250°F and 275°F during the tests.

A sample was drawn at a constant rate from the flue gas stream through a heated (maintained @ 248°F) probe/filter system, followed by a series of impingers located in an ice bath. The oxidized mercury was collected in the first set of impingers containing chilled aqueous potassium chloride (KCl) solution. The elemental mercury was collected in subsequent impingers (one containing chilled aqueous acidic solution of hydrogen peroxide and three impingers containing chilled acidic solutions of potassium permanganate).

The OH train samples were collected as follows:

- After sampling was completed, the sample train was leak-checked, dismantled, sealed with Teflon tape and transported to the sample recovery area.
- The particulate filter was removed from the filter bell, placed into the original petri dish, sealed with Teflon tape, and placed in a plastic bag. No analysis was conducted on the filter.
- The internal surfaces of the probe and front half of the filter bell were cleaned by rinsing and brushing three times with a 0.1N HNO_3 rinse. The sample was collected in an amber sample jar and sealed with a Teflon lid and Teflon tape.
- The contents of impingers one, two, and three were weighed to the nearest 0.5 gram to determine moisture gain. Small amounts (1 ml increments) of 5% $KMnO_4$ solution were added to each of the three KCl impingers. The $KMnO_4$ addition was continued until a purple color was maintained in the impingers. The contents were composited in a common sample container. Each impinger, and all connecting glassware, was rinsed with 10% HNO_3, and the rinsate was added to the composite sample container. Small amounts of 5% $KMnO_4$ solution were added to the sample composite until a purple color was maintained. The sample was collected in an amber sample jar and sealed with a Teflon lid and Teflon tape.
- The contents of impingers four and five were weighed to the nearest 0.5 gram to determine moisture gain. The contents were then placed in a dedicated sample container. These impingers were then rinsed with 0.1N HNO_3 and incorporated into the sample container. The composite sample was collected in an amber sample jar and sealed with a Teflon lid and Teflon tape.
- Impingers six, seven, and eight were weighed to the nearest 0.5 gram to determine moisture gain. The contents were composited in a common sample container. The impingers were rinsed twice with 0.1N HNO3, and once with 0.1N HNO3 mixed with a few drops of 10% hydroxylamine solution to remove residual KMnO4 solution.
- The rinsates and solutions were collected in an amber sample jar and sealed with a Teflon lid and Teflon tape. Impinger nine was weighed to the nearest 0.5 gram to determine moisture gain. The spent indicating silica gel was then placed in an appropriate container for transport back to the equipment staging area. No analysis was conducted on the silica gel.
- Quality control samples for the OH trains consisted of blanks for the filter, water, and all sample and recovery reagents used in the sample train.

Because of the highly quantitative aspect of the mercury analysis, special precautions were taken to avoid potential sample contamination. All key glassware components were thoroughly washed, rinsed with DI water and then soaked in a 10% nitric acid solution for four hours prior to the test program. All liquid samples were placed into acid washed glass bottles equipped with Teflon-lined caps.

Equipment Calibration

Equipment Calibration Overview

Proper equipment calibration is essential in maintaining the desired data quality level. All calibrations of the equipment used in the stack sampling portion of the testing conformed to the guidelines outlined in the EPA quality assurance handbook, Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods (EPA/600/R-94/038c). The following sections give a synopsis of the calibration procedures for the main components of the stack sampling systems.

Calibration Procedures

Dry Gas Meters/Orifice Meters

The dry gas meters and orifice meters in each control box used during the testing were calibrated before the test in order to ensure accurate measurements of the sample gas volumes. The dry gas meters and orifice meters are normally housed as a set inside each control box and were calibrated as such. These sets of meters were calibrated against a primary calibration standard, a spirometer.

The dry gas meter/orifice meter sets were calibrated at predetermined nominal volume flow settings. For each of these flow rates, an accuracy ratio factor to the calibration standard (Yi) was computed for the individual dry gas meters. A successful calibration for a particular dry gas meter would be achieved if each value of Yi was within 2 percent of the average value of Yi (Yi = Y ±0.02Y).

In order to establish calibration for the orifice meter, a calibration coefficient (H@I) was calculated for each flow rate. This coefficient is the orifice pressure differential (in inches H2O) at a distinct orifice manometer setting that gives a flow of 0.75 ft3/min of air at standard conditions. The desired tolerance for this coefficient is ±0.2 of the average value of the four values of H@I (H@ ±0.2). If any of the pre-test calibration coefficients for a particular meter violated the acceptance criteria, the meter in question would be adjusted and recalibrated.

Thermocouples and Thermocouple Readouts

All thermocouples used during the stack sampling tests were calibrated to ensure accurate temperature measurements. All of the sensors utilized were type "K" thermocouples, which have a working range of approximately -300 °F to approximately 2500 °F. These sensors were used in the measurement of stack gas temperature, organics trap temperature, probe sheath temperature, filter box temperature, and impinger temperature. The thermocouples were calibrated against an NIST traceable mercury-in-glass thermometer at predetermined temperatures. In order to obtain the calibration data from each sensor a single, recently calibrated thermocouple readout was used.

The thermocouple readouts used during the testing were calibrated using a thermocouple simulator. This calibration apparatus generates a voltage signal that mimics the signal an ideal "K" type thermocouple would exhibit at a particular temperature. The signal can be changed via a slide switch. The readouts were calibrated at ten different points from 200°F through 2000°F, at increments of 200°F.

Barometer

The field barometer used during the test was an aneroid type barometer. This barometer was calibrated by comparing it to a standard mercury column barometer and adjusting it if any deviation existed between it and the standard. This exercise was performed both before and after the testing activities.

Analytical Balance

The field analytical balance was calibrated before the test with certified standard weights. The balance was adjusted for any deviation from the standard weights. In the field, periodic checks were made to insure data validity. This balance was used to measure the impinger weight changes due to moisture gain during the stack sampling (determination of stack moisture content).

Pitot Tubes

The S-type Pitot tubes used on each isokinetic sampling train were calibrated based on geometric considerations. The basis for the calibration is described in 40 CFR, Part 60, Appendix A, Method 2.

Continuous Emission Monitors

Quality control procedures to be implemented during the testing included three-point calibrations, calibration drift tests, bias tests, and response time tests for each CEM monitor. A three-point calibration was conducted daily before and after each test burn run. These calibrations consisted of introducing pre-purified nitrogen as a zero gas and three known concentrations of each specific gas to the appropriate analyzer. EPA Protocol 1 calibration gases were used to perform these calibrations. Bias checks were also performed as part of the monitor calibrations. These checks were performed by introducing calibration gas at the point of sample extraction on the stack. This allowed calibration gases to travel through each complete monitoring system.

Response time tests were performed in conjunction with the bias checks. Alternating the introduction of span and zero calibration gas during the bias checks three times and recording the time required for the monitor to reach 95 percent of the final stable value enabled the determination of mean upscale and downscale response times.

Zero and calibration drift was also determined during each run of the tests. This was accomplished by comparing zero and upscale calibrations from before and after a test run.