INTERNAL PERMITTING DOCUMENT TRACKING MANIFES

Company Name MEA

Permitting Action Number R14-3007 Total Days 100 DAQ Days 35

Permitting Action:

- ❍ Permit Determination
- ❍ General Permit
- ❍ Administrative Update
- ❍ Temporary
- ❍ Relocation
- ❍ Construction
- ☒ Modification
- ❍ PSD (Rule 14)
- ❍ NNSR (Rule 19)

Documents Attached:

- ☒ Engineering Evaluation/Memo
- ☒ Draft Permit
- ☒ Notice
- ❍ Denial
- ❍ Final Permit/General Permit Registration
- ☒ Completed Database Sheet
- ❍ Withdrawal
- ❍ Letter
- ❍ Other *(specify)*

Date	From	To	Action Requested
3/2	Ed	Bev	Please Review
3/2	Ed	Bev	Please Review
3/3	Bev	Ed	See Comments - Addum - Go to Notice

NOTE: Retain a copy of this manifest for your records when transmitting your document(s).

Permit / Application Information Sheet
Division of Environmental Protection
West Virginia Office of Air Quality

Company:	Morgantown Energy Associates			**Facility:**	Morgantown
Region:	6	**Plant ID:**	061-00027	**Application #:**	R14-0007C
Engineer:	Andrews, Edward S.			**Category:**	Power Plt
Physical Address:	MORGANTOWN PLANT 555 BEECHURST AVENUE MORGANTOWN WV 26505			SIC: [4911] ELECTRIC, GAS AND SANITARY SERVICES - ELECTRIC SERVICES NAICS: [221112] Fossil Fuel Electric Power Generation	
County:	Monongalia				
Other Parties:	Gen_Mgr - Shirley, Todd 704-815-8022 ENV_CONT - Manley, Josh 304-284-2518				

Information Needed for Database and AIRS
No required information is missing.

Regulated Pollutants

Summary from this Permit R14-0007C

Air Programs		**Applicable Regulations**
MACT TITLE V		02 10 60 D 60 D a 63 A
Fee Program	**Fee**	**Application Type**
	$3,500.00	MODIFICATION

Notes from Database
Permit Note: This action is to allow a change in method of operation (increase amount fuel used) to reduce S03 emissions (acid gases for MATS).

Activity Dates

APPLICATION RECIEVED	11/23/2015
APPLICANT PUBLISHED LEGAL AD	11/25/2015
APPLICATION FEE PAID	11/30/2015 1000
ASSIGNED DATE	11/30/2015
APPLICATION FEE PAID	12/04/2015 2500
APPLICATION DEEMED COMPLETE	01/27/2016

NON-CONFIDENTIAL

Please note, this information sheet is not a substitute for file research and is limited to data entered into the AIRTRAX database.

Company ID: 061-00027
Company: Morgantown Energy Associates
Printed: 03/02/2016
Engineer: Andrews, Edward S.

West Virginia Department of Environmental Protection

Earl Ray Tomblin
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Permit to Modify

R14-0007C

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 C.S.R. 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:

Morgantown Energy Associates
Morgantown Energy Facility
061-00027

____

William F. Durham
Director

Issued: DRAFT

Entire Document
NON-CONFIDENTIAL

This permit will supercede and replace Permit R13-1058B/R14-0007B.

Facility Location:	555 Beechurst Avenue Morgantown, Monongalia County, West Virginia 26505
Mailing Address:	Same as above
Facility Description:	Fossil Fuel Fired Cogeneration Facility
NAICS Codes:	221112
UTM Coordinates:	589.20 km Easting • 4,388.10 km Northing • Zone 17
Permit Type:	Modification
Description of Change:	This action is for the change in method of operation for the two fluidized bed boilers to permit the installation and subsequent operation of the SNCR systems on both CFB boilers. This action also addresses the requirements pursuant to 40 CFR 63 Subpart UUUUU (Mercury and Air Toxics Rule, MATS).

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Table of Contents

1.0. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S001A	Vents 1 & 2	Elevating Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001B	Vents 1 & 2	TP001B – Elevating Conveyor1 to Reversible Feed Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001C	Vents 1 & 2	Reversible Feed Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001D	Vent 1	TP001D - Reversible Feed Conveyor 1 to Coal Silo 1	1989	500 TPH	ES 1/BH 1
S001E	Vent1	Coal Silo 1	1989	2,100 Tons	ES 1 / BH 1
S001F	Vents 1 & 2	TP001F - Elevating Conveyor 1 to Emergency Bypass Conveyor	2001	120 TPH	ES 1 / BH 1 & 2
S002A	Vent 2	TP002A - Reversible Feed Conveyor 1 to Gob Storage Silo 1	1989	500 TPH	ES 1 / BH 2
S002B	Vent 2	Gob Storage Silo 1	2001	2,100 Tons	ES 1 / BH 2
S003A	Vent 3	TP003A – Coal Silo 1 to Weigh Belt Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003B	Vent 3	TP003B – Gob Storage Silo 1 to Weigh Belt Conveyor 2	1989	60 TPH	ES 2 / BH 3
S003C	Vent 3	Weigh Belt Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003D	Vent 3	Weigh Belt Conveyor 2	2001	60 TPH	ES 2 / BH 3
S003E	Vent 3	TP003E - Weigh Belt Conveyor 1& 2 to Grinding Mill	1989	60 TPH	ES 2 / BH 3
S003F	Vent 3	TP003F - Weigh Belt Conveyor 1& 2 to Hammer Mill	1989	60 TPH	ES 2 / BH 3
S003G	Vent 3	TP003G – Emergency Mill Feed System Hopper 1 to En-mass Elevating Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003H	Vent 3	En-mass Elevating Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003I	Vent 3	TP003I – En-mass Elevating Conveyor 1 to Mill Inlet Chute System	1989	60 TPH	ES 2 / BH 3
S003J	Vent 3	Grinding Mill 1	1989	60 & 90 TPH	ES 2 / BH 3
S003K	Vent 3	Hammer Mill 1	1989	60 TPH	ES 2 / BH 3

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S004A	Vent 4	TP004A – Grinding Mill 1 to Mill Collecting Conveyor 1	1989	60 & 90 TPH	ES 3 / BH 4
S004B	Vent 4	TP004B – Hammer Mill 1 to Mill Collecting Conveyor 1	1989	60 TPH	ES 3 / BH 4
S004C	Vent 4	TP004C – Baghouse 4 Dust Discharge to Mill Collecting Conveyor 1	1989	5 TPH (est.)	ES 3 / BH 4
S004D	Vent 4	Mill Collecting Conveyor 1	2001	120 TPH	ES 3 / BH 4
S004E	Vent 4	TP004E – Mill Collecting Conveyor 1 to Elevating Conveyor 2	1989	120 TPH	ES 3 / BH 4
S004F	Vent 4	TP004F – Baghouse 3 Dust Discharge to Mill Collecting Conveyor 1	1989	12 TPH	ES 3 / BH 4
S004G	Vent 4	Elevating Conveyor 2 (Bottom Half)	2001	120 TPH	ES 3 / BH 4
S005A	Vent 5	Elevating Conveyor 2 (Top Half)	1989	120 TPH	ES 4 / BH 5
S005B	Vent 5	TP005B – Elevating Conveyor 2 to Fuel Bin 1	1989	120 TPH	ES 4 / BH 5
S005C	Vent 5	TP005C – Elevating Conveyor 2 to Fuel Bin 2	1989	120 TPH	ES 4 / BH 5
S005D	Vent 5	Fuel Bin 1	1989	375 Tons	ES 4 / BH 5
S005E	Vent 5	Fuel Bin 2	1989	375 Tons	ES 4 / BH 5
S005F	Vent 5	Emergency Bypass Conveyor	2001	120 TPH	ES 4 / BH 5
Limestone Handling					
S006A	Vent 6	TP006A – Transfer from Truck to Limestone Unloading Hopper 1	1989	37.5 TPH	BE 2 / BH 6
S006B	Vent 6	TP006B – Transfer from Truck to Limestone Unloading Hopper 2	1989	37.5 TPH	BE 2 / BH 6
S006C	Vent 6	Limestone Unloading Hopper 1	1989	75 TPH	BE 2 / BH 6
S006D	Vent 6	Limestone Unloading Hopper 2	1989	75 TPH	BE 2 / BH 6
S007A	Vent 7 & 8	TP007A – Transfer from Limestone Unloading Hopper 1 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S007B	Vent 7 & 8	TP007B – Transfer from Limestone Unloading Hopper 2 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S007C	Vent 7 & 8	TP007C – Transfer from Truck to Pneumatic Conveying System 1	1989	75 TPH	PCS 1

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S007D	Vent 7	TP007D – Transfer from Pneumatic Conveying System 1 to Limestone Silo 1	1989	75 TPH	ES 5 / BVF 1
S007E	Vent 7	Limestone Silo 1	1989	1,160 Tons	ES 5 / BVF 1
S008A	Vent 8	TP008A – Transfer from Limestone Silo 1 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S008B	Vent 8	TP008B – Transfer from Pneumatic Conveying System 1 to Limestone Bin 1	1989	75 TPH	ES 6 / BVF 2
S008C	Vent 8	Limestone Bin 1	1989	250 Tons	ES 6 / BVF 2
S008D	Vent 8	TP008D– Limestone Bin 1 to Gravimetric Feeder/Conveyor A	1989	10 TPH	ES 6 / BVF 2
S008E	Vent 8	Gravimetric Feeder/Conveyor A	1989	10 TPH	ES 6 / BVF 2
S008F	Vent 8	TP008F– Gravimetric Feeder/Conveyor A to Rotary Valve A	1989	10 TPH	ES 6 / BVF 2
S008G	Vent 8	TP008G– Limestone Bin 1 to Gravimetric Feeder/Conveyor B	1989	10 TPH	ES 6 / BVF 2
S008H	Vent 8	Gravimetric Feeder/Conveyor B	1989	10 TPH	ES 6 / BVF 2
S008I	Vent 8	TP008I– Gravimetric Feeder/Conveyor B to Rotary Valve B	1989	10 TPH	ES 6 / BVF 2
Boiler & Associated Equipment					
S009A	STACK 1	TP009A - Limestone Feeder Rotary Valve A to Pneumatic Conveying System 2	1989	10 TPH	PCS / BH 7 & 8
S009B	STACK 1	TP009B - Limestone Feeder Rotary Valve B to Pneumatic Conveying System 2	1989	10 TPH	PCS / BH 7 & 8
S009C	STACK 1	TP009C - Pneumatic Conveying System 2 to CFB Boiler 1	1989	10 TPH	PCS / BH 7 & 8
S009D	STACK 1	TP009D - Pneumatic Conveying System 2 to CFB Boiler 2	1989	10 TPH	PCS / BH 7 & 8
S009E	STACK 1	TP009E – Fuel Bin 1 to Enclosed Conveying System 7	1989	46 TPH	ES / BH 7 & 8
S009F	STACK 1	TP009F – Fuel Bin 2 to Enclosed Conveying System 7	1989	46 TPH	ES / BH 7 & 8
S009G	STACK 1	Enclosed Conveying System 7 to CFB Boiler 1	1989	46 TPH	ES / BH 7 & 8

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S009H	STACK 1	Enclosed Conveying System 7 to CFB Boiler 2	1989	46 TPH	ES / BH 7 & 8
S009J	STACK 1	Ahlstrom Pyroflow CFB Boiler/Cyclone #1	1989, SNCR 2016	375 MMBtu/hr	Limestone Injection, BH 8 & SNCR
S009K	STACK 1	Ahlstrom Pyroflow CFB Boiler/Cyclone #2	1989, SNCR 2016	375 MMBtu/hr	Limestone Injection, BH 7 & SNCR
S009L	STACK 1	Zurn Auxiliary Boiler #1	1989	132 MMBtu/hr	LNB
S009M	STACK 1	Zurn Auxiliary Boiler #2	1989	132 MMBtu/hr	LNB
Ash Handling					
S010A	Vent 9	TP010A – CFB Boiler 1 Bottom Ash Screw A to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010B	Vent 9	TP010C – CFB Boiler 1 Bottom Ash Screw B to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010C	Vent 9	TP010E – CFB Boiler 1 Bottom Ash Screw C to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010D	Vent 9	Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010E	Vent 9	TP010I – CFB Boiler 2 Bottom Ash Screw A to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010F	Vent 9	TP010K – CFB Boiler 2 Bottom Ash Screw B to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010G	Vent 9	TP010M – CFB Boiler 2 Bottom Ash Screw C to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010H	Vent 9	Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010I	Vent 9	TP010Q – Drag Chain Conveyor 101 to Clinker Grinder 1	1989	16.5 TPH	ES 8 / BVF 3
S010J	Vent 9	TP010S – Drag Chain Conveyor 201 to Clinker Grinder 3	1989	16.5 TPH	ES 8 / BVF 3
S010K	Vent 9	Clinker Grinder 1	1989	16.5 TPH	ES 8 / BVF 3
S010L	Vent 9	Clinker Grinder 3	1989	16.5 TPH	ES 8 / BVF 3

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S010M	Vent 9	TP010Y – Clinker Grinder 1 to Bottom Ash Holding Bin 1	1989	16.5 TPH	ES 8 / BVF 3
S010N	Vent 9	TP010AA – Clinker Grinder 3 to Bottom Ash Holding Bin 1	1989	16.5 TPH	ES 8 / BVF 3
S010O	Vent 9	Bottom Ash Holding Bin	1989	76.5 Tons	ES 8 / BVF 3
S011A	Vent 10	TP011A – Bottom Ash Holding Bin Discharge A to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011B	Vent 10	TP011B – Bottom Ash Holding Bin Discharge B to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011C	Vent 10	TP011C – Bottom Ash Holding Bin Discharge C to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011D	Vent 10	TP011D – CFB No. 1 Air Heater Hopper to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011E	Vent 10	TP011E – CFB No. 2 Air Heater Hopper to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011F	Vent 10	TP011F – CFB No. 1 Baghouse Row 1 Discharge to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011G	Vent 10	TP011G – CFB No. 1 Baghouse Row 2 Discharge to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011H	Vent 10	TP011H – CFB No. 2 Baghouse Row 1 Discharge to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011I	Vent 10	TP011I – CFB No. 2 Baghouse Row 2 Discharge to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011J	Vent 10	Filter/Separator A Exhaust	1989	50 TPH	ES 3 / VCS A / FS A
S011K	Vent 10	Filter/Separator B Exhaust	1989	50 TPH	ES 3 / VCS B / FS B
S011L	Vent 10	Filter/Separator C Exhaust	1989	50 TPH	ES 3 / VCS C / FS C
S012A	Vent 11	TP012A – Filter/Separator A to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012B	Vent 11	TP012B – Filter/Separator B to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012C	Vent 11	TP012C – Filter/Separator A to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012D	Vent 11	Ash Silo1	1989	1,300 Tons	ES 9 / BH 9

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S012E	Vent 11	TP012E – Ash Silo to Truck	1989	300 TPH	BH 9 / BE 4 / AC 1
S012F	Vent 11	TP012FE – Ash Silo to Truck	1989	300 TPH	BH 9 / BE 4 / AC 2
Fuel Receiving & Emergency Fuel Feed Fugitives					
S00F1	Fugitive Emission 1	TP00F1 – Transfer from Truck to Fuel Unloading Hopper/Vibratory Feeder 1	1989	250 TPH	BE 1 / WS 1
S00F2	Fugitive Emission 2	Fuel Unloading Hopper 1	1989	250 TPH	BE 1 / WS 1
S00F3	Fugitive Emission 3	Vibratory Feeder 1	1989	250 TPH	BE 1 / ES 1
S00F4	Fugitive Emission 4	TP00F4 – Transfer from Truck to Fuel Unloading Hopper/Vibratory Feeder 2	1989	250 TPH	BE 1 / WS 2
S00F5	Fugitive Emission 5	Fuel Unloading Hopper 2	1989	250 TPH	BE 1 / WS 2
S00F6	Fugitive Emission 6	Vibratory Feeder 2	1989	250 TPH	BE 1 / ES 1
S00F7	Fugitive Emission 7	TP00F7 – Vibratory Feeder 2 to Transfer Conveyor 1	1989	250 TPH	BE 1 / ES 1 / WS 3
S00F8	Fugitive Emission 8	TP00F8 – Vibratory Feeder 1 to Transfer Conveyor 1	1989	250 TPH	BE 1 / ES 1 / WS 4
S00F9	Fugitive Emission 9	Transfer Conveyor 1	1989	500 TPH	BE 1 / ES 1
S00F10	Fugitive Emission 10	TP00F10 – Transfer Conveyor 1 to Elevating Conveyor 1	1989	500 TPH	BE 1 / ES 1 / WS 5
S00F11	Fugitive Emission 11	TP00F11 – Dribble Chute 1 to Dribble Chute Catch Bin 1	1989	N/A	BE 1
S00F12	Fugitive Emission 12	Dribble Chute Catch Bin 1	1989	N/A	BE 1
S00F13	Fugitive Emission 13	TP00F13 – Dribble Chute Catch Bin 1 to Dribble Chute Conveyor 1	1989	N/A	BE 1
S00F14	Fugitive Emission 14	TP00F14 – Dribble Chute Conveyor 1 to Transfer Conveyor 1	1989	N/A	BE 1

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S00F15	Fugitive Emission 15	TP00F15 – Front End Loader to Emergency Mill Feed System Hopper 1	1989	60 TPH	N/A
S00F16	Fugitive Emission 16	Emergency Mill Feed System Hopper 1	1989	60 TPH	N/A

[1] AC – Ash Conditioner; BH – Baghouse; BE – Building Enclosure; BVF – Bin Vent Filter; ES – Enclosed System; FS – Filter Separator; LNB – Low NO_x Burners; SNCR – Selective Non-catalytic Reduction System, PCS – Pneumatic Conveying System; VCS – Vacuum Conveying System; WS – Water Spray.

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments	**NOx**	Nitrogen Oxides
CBI	Confidential Business Information	**NSPS**	New Source Performance Standards
CEM	Continuous Emission Monitor	**PM**	Particulate Matter
CES	Certified Emission Statement	**$PM_{2.5}$**	Particulate Matter less than 2.5 µm in diameter
C.F.R. *or* CFR	Code of Federal Regulations	**PM_{10}**	Particulate Matter less than 10µm in diameter
CO	Carbon Monoxide	**Ppb**	Pounds per Batch
C.S.R. *or* CSR	Codes of State Rules	**Pph**	Pounds per Hour
DAQ	Division of Air Quality	**Ppm**	Parts per Million
DEP	Department of Environmental Protection	**Ppmv or ppmv**	Parts per Million by Volume
dscm	Dry Standard Cubic Meter	**PSD**	Prevention of Significant Deterioration
FOIA	Freedom of Information Act	**Psi**	Pounds per Square Inch
HAP	Hazardous Air Pollutant	**SIC**	Standard Industrial Classification
HON	Hazardous Organic NESHAP	**SIP**	State Implementation Plan
HP	Horsepower	**SNCR**	Selective Non-catalytic Reduction
lbs/hr	Pounds per Hour	**SO_2**	Sulfur Dioxide
LDAR	Leak Detection and Repair	**TAP**	Toxic Air Pollutant
M	Thousand	**TPY**	Tons per Year
MACT	Maximum Achievable Control Technology	**TRS**	Total Reduced Sulfur
MDHI	Maximum Design Heat Input	**TSP**	Total Suspended Particulate
MM	Million	**TBtu**	Trillion British Thermal Units
MMBtu/hr *or* mmbtu/hr	Million British Thermal Units per Hour	**USEPA**	United States Environmental Protection Agency
MMCF/hr *or* mmcf/hr	Million Cubic Feet per Hour	**UTM**	Universal Transverse Mercator
NA	Not Applicable	**VEE**	Visual Emissions Evaluation
NAAQS	National Ambient Air Quality Standards	**VOC**	Volatile Organic Compounds
NESHAPS	National Emissions Standards for Hazardous Air Pollutants	**VOL**	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*;

2.3.2. 45CSR14 – *Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration;*

2.4. Term and Renewal

2.4.1. This permit supersedes and replaces previously issued Permit R13-1058B/R14-0007B. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule;

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-1058/R14-0007, R13-1058B/R14-0007B, R14-0007C, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.11 and 10.3.]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies; i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by

improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5 The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1.]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] ***[State Enforceable Only]***

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.1.7. All plant roads and haulways shall be paved and shall be kept clean by appropriate measures to minimize the emissions or entrainment of fugitive particulate matter.
[45 CSR §2-5.1.]

3.1.8. There shall be no open stockpiling of coal or coal refuse at the permitting facility.
[45 CSR §2-5.1.a.]

3.1.9. All truck delivering coal or coal refuse and trucks removing ash from the facility shall be fully covered or enclosed.
[45 CSR §§2-5.1. & 5.1.b.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

1. The permit or rule evaluated, with the citation number and language;
2. The result of the test for each permit or rule condition; and,
3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State Enforceable Only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class with postage prepaid to the address(es) set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

If to the DAQ:
Director
WVDEP
Division of Air Quality
601 57th Street
Charleston, WV 25304-2345

If to the US EPA:
Associate Director
Office of Air Enforcement and Compliance Assistance
(3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

3.5.4. Operating Fee

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements for the Boilers (CFB and Auxiliary Boilers)

4.1. Limitations and Standards

4.1.1. Particulate Matter (PM) emissions emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. PM emission rate shall not exceed 0.03 lb/MMBtu of heat input on a 30 day rolling average.
[45 CSR §2-4.1.b., and 40 CFR §60.42Da(a)]

b. PM concentration of no greater than 0.016 grains per dscf corrected to 3.5 percent oxygen.

c. Effective April 16, 2016, filterable PM emission rate shall not exceed 0.03 lb/MMBtu or 0.30 lb/MWh (gross basis) on a 30 boiler operating day rolling average.
[40 CFR §63.10005(a) Row 1a of Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs]

4.1.2. Sulfur Dioxide (SO_2) emissions emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. SO_2 emission rate shall not exceed 0.40 lb/MMBtu on a 30 day rolling average.
[40 CFR §60.43Da(a)(2)]

b. SO_2 concentration of no greater than 215 ppmvd per dscf corrected to 3.0 percent oxygen on a 24-hour average.

c. The SO_2 reduction efficiency from each unit shall not be less than 94.6% on a 30-day rolling average.
[40 CFR §60.43Da(a)(2)]

d. Effective April 16, 2016, the SO_2 emission rate shall not exceed 0.20 lb/MMBtu or 1.5 lb/MWh (gross basis) on a 30 boiler operating day rolling average.
[40 CFR §§63.9991(c), §63.10005(a)(2)(i), Row 1b of Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs, 45 CSR §10-3.1.]

e. The permittee shall operate a dry flue gas desulfurization system for the unit at all times consistent with 40 CFR §63.10000(b). Compliance with is requirement is satisfied through the use limestone injection into the CFB boilers coupled with the fabric filter collection system.
[40 CFR §63.9991(c)(2)]

4.1.3. Emissions of nitrogen oxides (NO_x), expressed as NO_2, emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. NO_x concentration shall not exceed 293 ppmvd corrected to 3 % oxygen on a 24-hr average basis.

b. NO_x emission rate shall not exceed 0.40 lb/MMBtu on a 30 day rolling average.

c. The permittee shall operate the SNCR in such manner to maintain compliance with the above NO_x limits and in Condition 4.1.17.

4.1.4. Emissions of carbon monoxide (CO) emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. CO concentration shall not exceed 188 ppmvd corrected to 3 % oxygen on a 24-hr average.

b. CO emissions rate shall not exceed 0.157 lb/MMBtu.

4.1.5. Emissions of volatile organic compounds (VOC) emitted to the atmosphere from each of the CFB boilers shall not exceed 0.0074 lb/MMBtu.

4.1.6. Emissions of mercury (Hg) emitted to the atmosphere from each CFB boiler shall not exceed 1.2 lb/TBtu or 0.013 lb/GWh (gross basis) based on a thirty (30) boiler operating day rolling average. **[40CFR§§63.9991(a)(1); Row 1c of Table 2 to Subpart UUUUU of Part 63; §63.10000(a); and §63.10010(g)]**

4.1.7. At all times, the permittee must operate and maintain each CFB boiler, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
[40 CFR §63.10000(b)]

4.1.8. The permittee shall conduct a tune-up of the burner and combustion controls of each CFB boiler at least once every 36 calendar months in accordance with the following:

a. The permittee must perform an inspection of the burner at least once every 36 calendar months. The permittee may delay the first burner inspection until the next scheduled unit outage provided the permittee meet the requirements of 40 CFR §63.10005.

b. As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

i. Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection;

ii. Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator.

c. As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

d. As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

e. As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

f. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

g. Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add- on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

h. While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_x and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continuous values before and after each optimization adjustment made by the system.
[40 CFR §63.9991(a)(1), Row 1 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards, 40 CFR 10021(e)]

4.1.9. During startup and shut down operations, the permittee must operate all continuous monitoring systems associated with the CFB boilers.
[40 CFR 63.10000(a), Rows 3 & 4 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

4.1.10. For startup of each CFB boiler, the permittee shall use natural gas to the maximum extent possible throughout the startup period. The permittee shall operate the associated PM control device for the unit within one hour of adding coal to the unit.
[40 CFR 63.10000(a), Row 3 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

4.1.11. During shutdown of each CFB boiler, the permittee shall operate all applicable control devices and continue to operate those control devices after the cessation of coal fuel being feed into the units and for as long as possible thereafter considering operational and safety concerns.
[40 CFR 63.10000(a), Row 4 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

4.1.12. If the permittee elects to demonstrates compliance with PM and/or Hg emissions limit of Condition 4.1.1.c. and/or Condition 4.1.6, respectively, through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan in accordance with Conditions 3.5.1. at least 60 days before the initial performance evaluation (where applicable) of the CMS. The site-specific monitoring plan shall include the information specified in 40 CFR 63.10000(d)(5)(i) through (d)(5(vii). The permittee must operate and maintain the CMS according to the site-specific monitoring plan.
[40 CFR §§63.10000(d)(1), (d)(2) and (d)(4)]

4.1.13. Before October 13, 2016, the permittee shall either demonstrate initial compliance of the filterable particulate matter (PM) standard (Condition 4.1.1.c.) or demonstrate that the CFB boilers qualify as a low emitting EGU (LEE) for filterable PM in accordance with 40 CFR 63.10005(h).
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(iv)]

4.1.14. Before October 13, 2016, the permittee shall demonstrate initial and continuous compliance of the applicable hydrogen chloride (HCl) standard in Subpart UUUUU to Part 63 or the alternative to the HCl standard, which is the SO_2 standard (Condition 4.1.2.c), using SO_2 CEMS in accordance with Condition 4.2.1.
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(v)]

4.1.15. Before October 13, 2016, the permittee shall demonstrate initial compliance of the mercury standard of 40 CFR §63.10005(a) (Condition 4.1.6.) or demonstrate that the CFB boilers qualify as a low emitting EGU (LEE) for mercury in accordance with 40 CFR 63.10005(h).
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(vi)]

4.1.16. The following conditions and requirements are specific to the auxiliary boilers (ID S009L and S009M):

a. During those periods when neither of the two fluidized bed boilers are in operation but steam demand for the West Virginia University requires operation of either or both of the gas-fired auxiliary boilers, emission from the common stack shall not exceed the emission limits in Table 4.1.16.a.

Table 4.1.16.a. Emission Limits for the Auxiliary Boilers		
Pollutant	lb/hr	lb/MMBtu
Particulate Matter (PM)	1.20	0.0045
Sulfur Dioxide (SO_2)	0.14	$5.3 X10^{-4}$
Nitrogen Oxides (NO_x)	50	0.189*
Volatile Organic Compounds (VOC)	1.95	0.0074
Carbon Monoxide (CO)	10	0.038

* Emission limit shall be demonstrated on a 30 day rolling average basis. **[40 CFR §60.44b(i)]**

b. The permittee shall conduct annual tune-ups of each boiler once every year in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. Subsequent tune-ups shall be conducted no later than 13 months from previous tune-up. If the unit is not operating on the required date for a tune-up, then the tune-up must be conducted within 30 calendar days of re-startup. These tune-ups shall consist of the following:

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment, but each burner must be inspected at least once every 12 months;

ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown);

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, which includes the verifying or ensure the manufacturer's NO_x concentration specification are maintained;

v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).

[40 CFR §§63.7500(a)(1) & (c); §63.7505(a); §63.7510(e); §63.7515(d); §§63.7540(a)(10), (11) & (12); and Table 3 to Subpart DDDDD of Part 63—Work Practice Standards]

4.1.17. During periods when the CFB boilers are operation, the emissions from Stack 1 shall not exceed the following emission limitation:

a. Particulate matter emission shall not exceed 22.5 pounds per hour.

b. When the auxiliary boiler(s) are in operation, the PM emission rate shall not exceed 0.022 lb/MMBtu.

c. Sulfur dioxide emission shall not exceed 285 pounds per hour on a 24-hour average basis.

d. Nitrogen oxides (NO_x) emission shall not exceed 300 pounds per hour on a 24-hours average basis.

e. Carbon monoxide (CO) emissions shall not exceed 117.5 pounds per hour except when the auxiliary boiler(s) are in operation as well, then the CO emission rate shall not exceed 127.5 pounds per hour.

f. Volatile organic compounds (VOC) emissions shall not exceed 5.5 pounds per hour except when the auxiliary boiler(s) are in operation as well, then the VOC emission rate shall not exceed 7.5 pounds per hour.

g. Lead emissions shall not exceed 0.13 pound per hour.

h. Mercury emissions shall not exceed 0.021 lb/hr

i. Fluorides emissions shall not exceed 0.4 pounds per hour.

j. Beryllium emissions shall not exceed 0.0002 pounds per hour.

k. Arsenic emissions shall not exceed 0.002 pounds per hour.

l. Radionuclides emissions shall not exceed 0.0009 pounds per hour.

m. Visible emissions shall not exceed 10% opacity based on a six minute average.
[45 CSR §2-3.1. and 40 CFR §60.42Da(b)]

4.1.18. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.11.]

4.2. Monitoring Requirements

4.2.1. *Continuous Monitoring Requirements:* The permittee shall install, calibrate, maintain and operate CEMS, continuous opacity monitor (COMS) and a diluent monitor to measure and record the emissions of SO_2, NO_x, and other parameters to determine compliance from the CFB boilers and the auxiliary boilers venting through Stack 1 in a manner sufficient to demonstrate continuous compliance with the SO_2 and NO_x emission standards in Conditions 4.1.2. 4.1.3. 4.1.16.a., and 4.1.17. and the opacity standard of Condition 4.1.17.m. Such records of this monitoring system, data collected, and calculated values shall be maintained in accordance with Condition 3.2.1. These systems shall be installed, calibrated, properly functioning, and certified in accordance with the following requirements:

a. *SO_2 CEMS:* The SO_2 CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75 provide that the requirements of 40 CFR §60.49a(b(4)(i – iii) are met. Record keeping and reporting shall be conducted pursuant Subpart F and G in 40 CFR 75. **[40 CFR §60.49a(b)(4) and 45 CSR §10-8.2.c.1.]**

i. For each hour in which valid data are obtained for all parameters, the permittee must calculate the SO2 emission rate and the calculated pollutant emission rate to each unit that shares the common stack, which is Stack 1 for CFB #1, CFB #2, and both auxiliary boilers. **[40 CFR §63.10010(a)(3)(B)]**

ii. For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in Sections 2.1 through 2.3 of Appendix B to Part 75 of Chapter 40, with the following addition: The permittee must perform the linearity checks required in Section 2.2 of Appendix B to Part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.
[40 CFR §60.49Da(b)(3) and 40 CFR §63.10010(f)(2)]

iii. Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.
[40 CFR §63.10010(f)(3)]

iv. Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the Part 75 SO_2 data and do not use Part 75 substitute data values. For startup or shutdown hours (as defined in 40 CFR §63.10042) the default electrical load and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in 40 CFR §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO_2 emission rate for any of these hours.
[40 CFR §60.49Da(b)(4)(iii) and 40 CFR §63.10010(f)(4)]

b. *NO_x CEMS:* The NO_x CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75.

For use of NO_x CEMS used to demonstrate compliance for the auxiliary boilers (S009L and S009M), the permittee shall also meet the requirements of 40 CFR §60.49b. Data reported to meet the requirements of 40 CFR §60.49b for the auxiliary boilers shall not include data substituted using the missing data procedures in Subpart D of Part 75 of Chapter 40, nor shall the data have been bias adjusted according to the procedures of Part 75 of Chapter 40.
[40 CFR §60.48b(b)(2)]

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where SO_2 and NO_x are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
[40 CFR §60.49Da(b)(4)(i) and 40 CFR §60.48b(b)(1)]

i. If the permittee use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of emissions limit in Conditions 4.1.1.b.i., the O2 or CO2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The permittee must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.
[40 CFR §§6310010(b)]

d. *Flow Monitor:* The volumetric flow rate of the flue gas shall be monitored at the location where SO_2 and NO_x are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
[40 CFR §60.49Da(m)]

e. *COMS:* Exhaust gas opacity from Stack 1 shall be monitored using a continuous opacity monitoring system for the purpose of demonstrating compliance with Condition 4.1.17.l. The permittee shall install calibrate, maintain, and operate the COMS in accordance with Performance Specification (PS) 1 in 40 CFR Part 60, Appendix B.
[40 CFR §§60.49Da(a) and (a)(1), 45 CSR §2-8.2.a.1., and 45 CSR §2A-6.2.]

f. *Hg CEMS or sorbent trap monitoring system:* The permittee must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with Appendix A to Subpart UUUUU of Part 63, Chapter 40 if both CFB boilers do not qualify as a LEE unit for Hg in accordance with 40 CFR 63.10005(h). The permittee must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A to Subpart UUUUU of Part 63, Chapter 40, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A to Subpart UUUUU of Part 63, Chapter 40 explains how to reduce sorbent trap monitoring system data to an hourly basis.
[40 CFR §63.10000(c)(1)(vi) and §63.10010(g)]

g. *PM CPMS or PM CEMS:* The permittee shall implement one of these monitoring operations to demonstrate compliance with the PM limit of Condition 4.1.1c. if both CFB boilers do not qualify as a LEE unit for PM in accordance with 40 CFR §63.10005(h).
[40 CFR §63.10000(c)(1)(iv)]

i. Install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in 40 CFR §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the CFB Boilers in tables 1 or 2 to this subpart;
[40 CFR §§63. 10010(i)]

ii. Use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in 40 CFR §§63.10010(h)(1) through (5) of this section; or
[40 CFR §§63. 10010(h)]

iii. Conduct quarterly performance testing to demonstrate compliance with the emission standard. This testing must be conducted in accordance with the applicable test methods as defined in Table 5 to Subpart UUUUU of Part 63 and calculate the results of the testing in units of the emission standard.
[40 CFR §§63.10021(d)]

h. NO_x & SO_2 CEMS: The permittee shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the permittee shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in 40 CFR §60.49Da(h) for SO_2 and Test Method 7 or 7A for NO_x.
[40 CFR §60.49Da(f)(1) and §60.48b(f)]

i. NO_x and SO_2 Emissions: The permittee shall determine 30 day rolling average for each of the CFB boilers for NO_x and SO_2, in accordance with 40 CFR §60.48Da, which is to be expressed in lb/MMBtu. The permittee shall determine the 30 day rolling average of NO_x in accordance with 40 CFR §60.48b, which is to be expressed in lb/MMBtu.
[40 CFR §60.48Da and §60.48b]

j. Records of maintaining, calibrations, checks, and output data, shall be maintained in accordance with Condition 3.4.1. The permittee must monitor and collect data according to 40 CFR 63.10020 and the site-specific monitoring plan required in Condition 4.1.1.
[40 CFR 63.10020(a) and (b)]

4.2.2. The permittee shall install, calibrate, maintain, and operate an "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A of Part 60 be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under 40 CFR 60.49Da(b)(1). The permittee shall use the output data from the "as fired" system and SO_2 CEMS to determine compliance with the percent SO_2 reduction of Condition 4.1.2.c. in accordance with 40 CFR §60.50Da(c) on daily and 30 successive boiler operating days basis. Such records of this monitoring system, data collected, and calculated values shall be maintained in accordance with Condition 3.2.1.
[40 CFR §§60.49Da(b) & (b)(3), and §§60.50Da(a) & (c)]

4.3. Testing Requirements

4.3.1. If the permittee elects to demonstrate that CFB #1 and CFB #2 qualify as low emitting EGU (LEE) for PM in accordance with 40 CFR 63.10005(h), the permittee shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status. The permittee must conduct all required performance tests described in 40 CFR §63.10007 to demonstrate that a unit qualifies for the LEE status. If the permittee satisfactorily demonstrates that both units qualify as LEE units for PM, then the PM portion of the site specific monitoring plan of Condition 4.1.1.1 and the monitoring of Condition 4.2.1.g are stayed until the unit no longer qualifies as a LEE unit for filterable PM. Should subsequent emissions testing results show a unit(s) does not meet the LEE eligibility requirements, the permittee must conduct PM emissions testing quarterly in accordance with Condition 4.2.1.g.iii.
[40 CFR §63.10000(c)(1)(iv), §63.10006(b)(1), and §63.10020(d)(3)(i)]

When conducting emissions testing to demonstrate LEE status, the permittee must increase the minimum sample volume specified in Table 2 to Subpart UUUUU of Part 63 nominally by a factor of two.

For Hg, the permittee must conduct a 30-boiler operating day performance test using Method 30B in appendix A-8 to Part 60 of Chapter 40 to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the

duct at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. The permittee may use a pair of sorbent traps to sample the stack gas for no more than 10 days.
[40 CFR 63.10005(h)(3)]

For affected units meeting the LEE requirements of 40 CFR §63.10005(h), the permittee must repeat the performance test once every 3 years for filterable PM and once every year for Hg according to Table 5 to Subpart UUUUU of Part 63 – Performance Testing Requirements and 40 CFR §63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, then permittee must conduct PM emissions testing quarterly in accordance with Condition 4.2.1.g.iii.
[40 CFR §§63.10006(b) & (b)(1)]

If the affected units do not qualify for Hg LEE status, then permittee must install, certify, maintain, and operate an Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to Subpart UUUUU to Part 63, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the permittee must conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1). The permittee must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.
[40 CFR §63.10006(b)(2)]

Such testing shall be conducted in accordance with Condition 3.3.1. with notifications and reports submitted in accordance with Condition 4.5.4 and 4.5.5.
[40 CFR §63.10030(d), §§63.10031(f), (f)(5) and (f)(6)]

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit, and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. For Subpart UUUUU for the CFB boilers, the permittee shall maintain records of following:

a. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §40 CFR 63.10(b)(2)(viii).
[40 CFR §63.10032(a)(2)]

b. For each PM or Hg CEMS and PM CPMS, the permittee must keep records according to the following if applicable:

i. Records described in 40 CFR §63.10(b)(2)(vi) through (xi).

ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR §63.8(d)(3).

iii. Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

[40 CFR §§63.10032(b)(1) though (b)(4)]

c. The permittee must keep the records required in Table 7 to Subpart UUUUU of Part 63 including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to the permittee.
[40 CFR §63.10032(c)]

d. For each EGU subject to an emission limit, the permittee must also keep the following records:

i. Monthly fuel usage for each CFB boiler, including the type(s) of fuel and amount used.
[40 CFR 63.10032(d)(1) and 45CSR§2A-7.1.a.]

ii. For the CFB boilers that qualify as an LEE status under 40 CFR §63.10005(h), the permittee must keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant (filterable PM and/or Hg), and document that there was no change in source operations

including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.
[40 CFR 63.10032(d)(3)]

e. Regarding startup periods or shutdown periods:

i. The permittee must keep records of the occurrence and duration of each startup or shutdown;

[40 CFR §§63.10032(f)(1)]

ii. The permittee must keep records of the determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and
[40 CFR §§63.10032(f)(3)]

iii. The permittee must keep records of the information required in 40 CFR 63.10020(e).
[40 CFR §§63.10032(f)(4)]

f. The permittee must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment.
[40 CFR §63.10032(g)]

g. The permittee must keep records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 CFR §63.10032(h)]

h. The permittee must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.
[40 CFR §63.10032(i)]

i. The permittee may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR §§63.10000(c)(1)(vi)(B) and 40 CFR §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out -of-control periods, repairs associated with monitoring system malfunctions or monitoring system out -of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality- assured data collected during all other periods in assessing the operation of the control device and associated control system.
[40 CFR §63.100020(b)]

j. Except for periods of monitoring system malfunctions or monitoring system out -of-control periods, repairs associated with monitoring system malfunctions or monitoring system out -of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.
[40 CFR §63.10020(d)]

4.4.5. The permittee shall determine and record the ash and Btu content of the coal received at the facility. Such records shall be maintained in accordance with Condition 3.4.1. of this permit.
[45CSR§2A-7.1.a.4.]

4.4.6. The permittee shall record and maintain records as specified in the following for the two auxiliary boilers:

a. The amount of natural gas combusted during each day and calculate the annual capacity factor. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

b. All records shall be maintained in accordance with Condition 3.4.1.
[40 CFR 60.49b(d)(1)]

4.5. Reporting Requirements

4.5.1. For Subpart Da Reporting for SO2 and PM from the CFB boilers, the permittee shall submit reports to the Director and Administrator semiannually. The reporting periods shall begin on January 1 and July 1 with the end of the reporting periods ending on June 30 and December 31 respectively. These reports shall be postmarked by 30 days following the end of the reporting period. Such reports shall contain the following information.

a. For SO_2, the following information is reported to the Director for each 24-hour period.

i. Calendar date.

ii. The average SO_2 emission rates (lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

iii. The percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

iv. Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

v. Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

vi. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

vii. Identification of the times when the pollutant concentration exceeded full span of the CEMS.

viii. Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

ix. If the minimum quantity of emission data as required by 40 CFR §60.49Da (Condition 4.2.1.) is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of 40 CFR §60.48Da(h) is reported to the Administrator for that 30-day period:

1. The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

2. The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

3. The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.

4. The applicable potential combustion concentration.

5. The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

x. For any periods for which opacity, SO_2 or NO_X emissions data are not available; the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

xi. The responsible official of permitted facility shall submit a signed statement indicating whether:

1. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

2. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

3. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

4. Compliance with the standards has or has not been achieved during the reporting period.

xii. For the purposes of the reports required under 40 CFR §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.
[40 CFR §60.19(d) and §§60.51Da(b), (c), f), (h), and (i)]

4.5.2. The permittee shall submit a "Notification of Compliance Status" for the CFB Boilers to the Administrator before the close of business on the sixtieth (60th) day after completion of the initial compliance or LEE demonstration as required in Conditions 4.1.1.l., 4.1.1.m. and 4.1.1.n. Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the applicable information specified in 40 CFR §§63.10030(e)(1), though (e)(8). Such notification shall be submitted reference in Conditions 4.5.
[40 CFR §63.9(h)2(ii), §63.1005(k), §63.10011(e), §63.10030(e)]

4.5.3. Subpart UUUUU Reports for CFB boilers, the permittee must submit each report in Table 8 to Subpart UUUUU of Chapter 40 that applies to the CFB boilers. If continuously monitored Hg emissions are required to be used to demonstrate compliance with Condition 4.1.1.f., the permittee must also submit the electronic reports required under Appendix A to Subpart UUUUU, at the specified frequency.

The first compliance report must cover the period beginning on April 16, 2016 and ending on December 31, 2016.

The first compliance report must be postmarked or submitted electronically no later than January 31, 2017.

Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

The compliance report must contain the following information (40 CFR§§ 63.10031(c)(1) through (5)):

a. The information required by the summary report located in 40 CFR §63.10(e)(3)(vi).

b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non- waste determination by EPA or the permittee basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

c. Indicate whether the permittee burned new types of fuel during the reporting period. If the permittee did burn new types of fuel the permittee must include the date of the performance test where that fuel was in use.

d. Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to §63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 months and was delayed until the next scheduled unit shutdown.

e. For each instance of startup or shutdown:

   i. Include the information required to be monitored, collected, or recorded according to the requirements of 40 CFR §63.10020(e).

f. For each excess emissions occurring at an affected source where the permittee is using a CMS to comply with that emission limit or operating limit, the permittee must include the information required in 40 CFR §63.10(e)(3)(v) in the compliance report specified in 40 CFR §63.10031(c).

4.5.4. Prior to April 16, 2017, all reports subject to electronic submissions in 40 CFR §§63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs of 40 CFR §§63.10031(f) in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:

a. The facility name, physical address, mailing address (if different from the physical address), and county;

b. The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;

c. The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;

d. If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of this chapter;

e. If any of the EGUs described in 40 CFR §63. 10031(f)(6)(iii) of this section are in an averaging plan under 40 CFR §63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;

f. The identification of each emission point to which the report applies. An "emission point" is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (e.g., "Unit 2 stack," "common stack CS001," or "multiple stack MS001");

g. The rule citation (e.g., §63.10031(f)(1), §63.10031(f)(2), etc.) for which the report is showing compliance;

h. The pollutant(s) being addressed in the report;

i. The reporting period being covered by the report (if applicable);

j. The relevant test method that was performed for a performance test (if applicable);

k. The date the performance test was conducted (if applicable); and

l. The responsible official's name, title, and phone number.
[40 CFR §§63.10031(f)(6)]

4.5.5. On or after April 16, 2017, the permittee shall submit reports of the following activities as required under Subpart UUUUU of Part 63 in accordance with the corresponding regulation:

a. Performance testing shall be submitted in accordance with 40 CFR §63.10031(f);

b. Each CEMS performance evaluation and relative accuracy test audit for the CEMS in accordance with 40 CFR §63.10031(f)(1)

c. PM CEMS or PM CPMS data in accordance with 40 CFR §63.10031(f)(2)

d. Notification of Compliance Status and Compliance Report as required in Condition 4.5.3. in accordance with 40 CFR 63.10031(f)(3).
[40 CFR §§63.10031(f), (f)(1), (f)(2), (f)(4)]

4.5.6. All reports required by Subpart UUUUU not subject to the requirements in 40 CFR §§63.100031, paragraphs (f) introductory text and (f)(1) through (4) (Condition 4.5.5.) must be sent to the Administrator and Director in accordance with Condition 3.5.1.. If acceptable to both the Administrator and the permittee, these reports may be submitted on electronic media. The Administrator and Director retains the right to require submittal of reports subject to 40 CFR §§63.100031, paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.
[40 CFR 63.10031(f)(5)]

4.5.7. The permittee shall submit "Annual Compliance Reports" to the Director for the Auxiliary Boilers with the first report being submitted no later than January 31, 2017, and subsequent reports are due every year thereafter. Such reports shall contain the information specified in 40 CFR §§63.7550(c)(5) (i)through (iv) and (xiv) which are:

a. Permittee and facility name, and address;

b. Process unit information, emission limitations, and operating limitations;

c. Date of report and beginning and ending dates of the reporting period;

d. The total operating time during the reporting period of each affected unit;

e. Include the date of the most recent tune-up for the boiler; and

f. Include the date of the most recent burner inspection if it was not done within the specified time schedule and was delayed until the next scheduled or unscheduled unit shutdown.

[40CFR §§63.7550(b), (b)(1), (c)(1), & (c)(5)(i) though (iv) and (xiv)

5.0. Fuel, Limestone, and Ash Handling

5.1. Limitations and Standards

5.1.1. Coal/coal refuse and limestone handling/storage facilities shall consist of the following, and particulate emissions shall be controlled as specified with maximum particulate emissions not to exceed the following:

	Type/Identity of Particulate Matter Control Equipment	Particulate Emission Limitation for Control Equipment Discharge lb/hr
Coal/Gob Receiving Hoppers (Truck)	Enclosure and Water/Chemical Dust Suppression System	
Coal/Gob Receiving Hopper (Emergency Use)	Minimize Drop Height	
Elevating Transfer Conveyor No. 1, Two Fuel Silos, Reversible Silo Feed Conveyor, Hopper Transfer Conveyor, and Transfer Points	Enclosure and Evacuation to Baghouse	0.0002
Elevating (Tripper) Conveyor No. 2 (top), Two Fuel Day Bins, and Transfer Points	Enclosure and Evacuation to Baghouse	0.0002
Mill Collecting Conveyor, Elevating Conveyor No. 2 base	Enclosure and Evacuation to Baghouse	0.0002
Two Coal/Gob Crushers (Grinding Mill, Hammer Mill), Emergency Fuel Feed Conveyor, Weigh Belt Conveyor	Enclosure and Evacuation to Baghouse	0.099
One 1,160 Ton Limestone Storage Silo	Baghouse	0.014
Limestone Truck Unloading Hopper	Enclosure and Evacuation to Baghouse	0.027
One Limestone Day Bin	Baghouse	0.005

5.1.2. Ash transfer, storage and loading facilities shall consist of the following and particulate emissions from the entire system shall be controlled as specified with maximum particulate emissions not to exceed the following:

	Type/Identity of Particulate Matter Control Equipment	Particulate Emission Limitation for Control Equipment Discharge lb/hr
Pneumatic System for Collected Flyash and Bottom Ash Handling, One 1300 Ton Ash Silo, Vacuum Blowers	Enclosure and Evacuation to Baghouse	0.028
Fully Sealed Mechanical System for Bottom Ash/Cooler Rejects, One 85 Ton Bottom Ash Silo	Baghouse	0.028
Flyash Transport (Silo Vent)	Baghouse	0.184
Wet Ash Loadout (Flyash and Bottom Ash)	Rotary dustless (wet) unloaders shall thoroughly wet ash prior to loading and handling. Ash	

	loadout(s) shall be fully enclosed and evacuated to an ash silo baghouse during all ash loading.	

5.1.3. All fugitive particulate matter control systems shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter.

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ______________________________, representing the period beginning _____________________ and ending _____________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ____ ____________________
(please use blue ink) Responsible Official or Authorized Representative Date

Name & Title ______________________________ ______________________________
(please print or type) Name Title

Telephone No. ____________________________ Fax No. ____________________________

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1 This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

(ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.

Division of Air Quality
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Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
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ENGINEERING EVALUATION/FACT SHEET

BACKGROUND INFORMATION

Application No.:	R14-0007C
Plant ID No.:	061-00027
Applicant:	Morgantown Energy Associates (MEA)
Facility Name:	Morgantown Energy Facility
Location:	Morgantown
NAICS Code:	221112
Application Type:	Modification
Received Date:	November 23, 2015
Engineer Assigned:	Edward S. Andrews, P.E.
Fee Amount:	$3500.00
Date Received:	November 23, 2015 December 5, 2015
Complete Date:	January 27, 2016
Due Date:	April 25, 2016
Applicant Ad Date:	November 25, 2015
Newspaper:	*The Dominion Post*
UTM's:	Easting: 589.20 km Northing: 4,388.10 km Zone: 17
Description:	This application is to address the major source permitting issues for implementing the facility's compliance strategy with regards to complying with the Mercury and Air Toxic (MATS) Rule for the CFB units.

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DESCRIPTION OF PROCESS

Morgantown Energy Associates (MEA) is a West Virginia General Partnership with one location in Morgantown, West Virginia. The facility provides cogeneration services (steam and electric production) that supply steam to West Virginia University and the WVU medical center facilities and electric energy to MonPower, a subsidiary of FirstEnergy. The facility has two circulating fluidized bed (CFB) boilers identified as S009J and S009K. These CFB boilers are have a maximum heat input of 375 MMBtu/hr which can generated a combined steam output of about 560,000 pounds of steam per hour. These two unit are configured to burn a mixture of coal and coal refuse.

To support start-up operations and to provide a secondary means to meet the heat demand of the university, the facility operates two natural gas fired boilers with a combined maximum heat input of 264 MMBtu/hr.

There are fuel, limestone, and ash handling equipment associated with the facility that is used to support the operations of the two CFB boilers.

DESCRIPITION OF CHANGES

MEA has selected a MATS compliance strategy on the basis of Filterable Particulate Matter (PM), Sulfur Dioxide (S02), and Mercury (Hg). MEA has evaluated the facility and determined that the compliance strategy will include complying with the following standards:

- Filterable Particulate Matter (PM)- 0.015 lb/MMBtu (40 CFR 63.10005 (h)(l)(i)) using low emitting (LEE)electric utility steam generating units testing in lieu of Total non-Hg HAP metals or Individual HAP metals. If the units meet LEE, then the LEE compliance track will be followed. If the units do not meet the LEE requirement, then the facility will need to demonstrate compliance with the PM limit which must be demonstrated through continuous monitoring performance through the use of particulate matter continuous parameter monitoring system (CPMS), or a PM continuous emission monitoring system (CEMS), or compliance performance testing which is repeated on a quarterly basis to demonstrate compliance with 0.03 lb of filter PM per MMBtu limit.

- Sulfur dioxide ($S0_2$) - 0.20 lb/MMBtu (40 CFR Table 2 to Subpart UUUUU of Part 63) using an existing continuous emissions monitoring system along with a flue gas desulfurization system. This control strategy includes the existing limestoneinjection system for flue gas desulfurization, which requires compliance/adherence to §63.9991(c)(1) and (2).

- Mercury (Hg) - 0.12lb/trillion Btu (TBtu) or PTE 29.0 lb/yr (per unit) using LEE testing (40 CFR 63.10005(h)(l)(ii)(B)). The mercury limit under MATS is 1.2 lb/TBtu. If the units do not meet LEE requirements, then the facility will have to install and operate Hg CEMS or a sorbent trap monitoring system.

- Work Practices and Standards for tune-up of burner and combustion controls- the facility is required to tune up the electric generating unit (EGU) burner and the combustion controls. The initial tune-up is required by October 12, 2016 with subsequent tune-ups every 36 months. The site obtained a one year extension.

- Work Practice Standards for Startups and Shutdowns - the facility has to operate the continuous monitoring systems for the CFB boilers during periods of startups and shutdowns. The startup is on natural gas; once coal is fired all of the required controls must be engaged after permissive temperatures are achieved.

Meeting the MATS sulfur dioxide (SO2) limit of 0.20 lb/MMBtu will require operational changes. To meet this SO_2 limit under MATS, MEA proposes to enhance the removal efficiency for SO_2 from the existing limestone inject and fabric filter baghouses for each unit by increasing the amount of limestone injected from 10 to 30%. The limestone system is currently designed and permitted for the anticipated feed rates. This adjustment requires the fuel feed to increase by an estimated 1 to 3% to allow for the calcination of the limestone.

The increase in fuel rate for the boilers would constitute a change in the method of operation under 45 CSR 14 (West Virginia's Prevention of Significant Rule). To ensure that a significant increase of nitrogen dioxide emissions does not occur, MEA proposes to install a selective non-catalytic reduction (SNCR) system.

SITE INSPECTION

The facility was last inspected on June 11, 2014, by Mr. Brian Tephabock, Compliance and Enforcement Supervisor of the North Central Regional Office. As a result of the inspection, Mr. Tephabock determined that the facility is operating in compliance with all applicable regulations, rules, and permits.

ESTIMATE OF EMISSIONS BY REVIEWING ENGINEER

MEA proposes to maintain the same potential to emit or emission limits as stated in Permit R14-00007B for the CFB boilers, except for sulfur dioxide and mercury. The following table compares the permitted and the projected hourly rate.

Table #1 – Permitted and Projected Criteria Emissions				
Pollutant	Permitted under R14-007B		Projected Emission after the change	
	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu
Nitrogen Oxides (NO_x)	300	0.40	274.199	0.31
Sulfur Dioxide (SO_2)	285	0.40	172.00	0.20
Carbon Monoxide (CO)	127.5	0.1257	52.286	0.059
Particulate Matter (PM)	22.5	0.022	6.887	0.008
PM less than 10 micros* (PM_{10})	N/A	N/A	19.203	0.022
PM less than 2.5 micros* ($PM_{2.5}$)	N/A	N/A	17.384	0.020
Lead (Pd)	0.13	N/A	0.00206	0.000002
Volatile Organic Compounds	5.55	0.0074	1.002	0.001

* Includes the condensable fraction.

HAP emissions such as the metals to include mercury will not be reduced any further since MEA believes that the current operation is reducing these emissions to levels that are already below the emission standard set in the MATS Rule, and MEA plans on conducting the testing required to demonstrate the LEE status for filterable PM and mercury.

Acid gas emissions will decrease as MEA increases the level of controlling SO_2 to achieve the 0.20 lb/MMBtu standard. However, it is difficult to predict the efficiency of these other acid gases in relationship to SO_2 emissions. It is known that hydrogen fluoride and hydrogen cyanide are the most reactive of the acid gases towards limestone that has been calcined. And, hydrogen chloride and SO_2 are the least reactive of the acid gases. Therefore, the proposed increased level of controlling SO_2 will reduce the other acid gases.

The applicant estimated the potential fugitive emissions associated with increased use of fuel and limestone. The emissions from additional haul road traffic was 0.006 tons per year of PM, 0.0010 tons per year of PM_{10}, and 0.0003 tons per year of $PM_{2.5}$. The fugitive dust emissions from off-loading the additional fuel is 0.01 tons per year of PM, 0.005 tons per year of PM_{10}, and 0.0007 tons per year of $PM_{2.5}$.

REGULATORY APPLICABLILITY

The Morgantown Energy Facility is a major source under 45 CSR 14, the State of West Virginia's rule on Prevention of Significant Deterioration (PSD) under the Clean Air Act.

The first step in determining if the proposed modification will triggered a major modification of a major source and to determine which pollutants that the project is major for. MEA had elected to use the actual-to-projected-actual applicability test under 45 CSR §14-3.4.c., which is illustrated in the following equation:

$$Net\ Emission\ Change = PAE - BE - ECBA$$

Where:
PAE – Project Actual Emissions, in tons per year
BE – Baseline Emissions, in tons per year
ECBA – Emissions that could have been accommodated, in tons per year.

Both of the CFB boilers are considered existing emission units for the applicability test. Since these CFB boilers are classified as electric utility generating units, the applicant is only permitted to review and use the previous 5-year period (past actuals) in establishing the baseline emissions for this test. The applicant annualized the past emissions 24 month basis for each month from January 2010 to December 2014. The application was deemed complete on January 27, 2016. By rule only emissions that occurred before January 2011 cannot be used for this application because it is outside of the five year look back window for determining baseline emissions.

Table No. 3 Establishing Baseline for the NSR Pollutants		
Pollutant	Emissions (tpy)	Time Period
PM	26.50	Oct 12 to Sep 14
PM_{10}	74.71	Oct 12 to Sep 14
$PM_{2.5}$ Direct	67.03	Jan 11 to Dec 12
SO_2 (& precursor for $PM_{2.5}$)	970.72	Jan 13 to Dec 14
NO_x (precursor of Ozone and $PM_{2.5}$)	1,082.58	Jan 13 to Dec 14
CO	201.45	Jan 11 to Dec 14
VOCs	3.86	Oct 11 to Sep 13
Pb	0.008	Jan 11 to Dec 12

Projected actuals are needed for this applicability test. MEA used heat input and capacity factor projection, which were obtained from MEA's financial projections for operating years 2016 through 2020. Additional heat input was determined from the projected increase in limestone injection. MEA used a projected additional heat need for calcination of the limestone of 8.6 gigajoules (For 2016 and 2020 operating years, an extra 24 operating hours was include since they are leap years.

Table #4 PROJECTED OPERATION & EMISSIONS					
YEAR	2016	2017	2018	2019	2020
Capacity (%)	94%	90%	94%	94%	94%
Heat Input (MMBtu/yr)	6,233,021	5,956,839	6,217,996	6,217,996	6,233,021
Heat Input from Additional	153,108	203,921	214,117	214,117	214,703
Hours of Operation	8,301	7,884	8,278	8,278	8,301
NO_X (Tons)	993.3	958.3	1,000.5	1,000.5	1002.9*
SO_2 (Tons)	732.4*	616.1	643.2	643.2	644.8
CO (Tons)	189.4	182.7	190.8	190.8	191.2*
PM (Tons)	24.9	24.1	25.1	25.1	25.2*
PM_{10} (Tons)	69.6	67.1	70.1	70.1	70.2*

VOC(Tons)	3.6	3.5	3.7	3.7	3.7*
Lead (Pb) (Tons)	0.007	0.007	0.008	0.008	0.008*
$PM_{2.5}$ (Tons)	63.0	60.8	63.4	63.4	63.6*

* - Highest Project Year

Emissions that could have been accommodated are determined using the annualized single month minus the baseline emissions. Second, these emissions must be unrelated to the project and the emission units must been physically and legally allowed to emit these emissions. The following table will identify the annualized single month, month and year selected and the permitted emission limit.

Table #5 – Emission that Could have Been Accommodated (ECBA)

Pollutant	NO_x	SO_2	CO	PM	PM_{10}	VOC	Pd	$PM_{2.5}$
Max Monthly Emissions	102.00	94.6	19.45	2.56	7.14	0.37	0.00076	6.47
Month & Year	Mar 2014	Mar 2014	Jan 2012	Mar 2014	Mar 2014	Jan 2012	Jan 2012	Jan 2012
Annualized Emission	1,224.00	1,135.20	233.40	30.72	85.68	4.44	0.01	77.64
Permitted Emission Rate	1,314.00	1,248.30	514.65	98.55		24.31	0.57	
BE	1,082.58	970.72	201.45	26.50	74.71	3.86	0.008	67.03
ECBA	141.42	164.48	31.95	4.22	10.97	0.58	0.0020	10.61

BE – Baseline Emissions

ECBA – Emissions that Could have Been Accommodated

Table #6 Change in Emissions

Pollutant	Projected Actuals Emissions – PA (tpy)	Baseline Emissions – BE (tpy)	ECBA (tpy)	Net change in Emissions (tpy)	Significant Threshold Level (tpy)
NO_x	1,002.89	1082.58	141.44	- 221.13	40
SO_2	732.41	970.72	164.48	- 402.79	40
CO	191.24	201.45	31.95	- 42.16	100
PM	25.19	26.50	4.22	- 5.53	25
PM_{10}	70.23	74.71	10.97	- 15.45	15
VOC	3.67	3.86	10.97	-11.16	40
Pb	0.01	0.01	0.0020	0.00	0.6
$PM_{2.5}$	63.58	67.03	10.61	- 14.06	10

(-) – Represents decrease in emissions.

Therefore, the net emission change for this project is less than the significance level for each corresponding pollutant and therefore the project does not pose a significant increase in emissions of any regulated pollutant under the PSD program. Thus, this proposed project is not classified as a major modification and no further review under Rule 14 is required.

It should be noted that this project should result in no increase of any regulated NSR pollutant, and therefore 45 CSR §§14-19.8.c. and d. would not be applicable to this project.

With regards to the National Ambient Air Quality Standards, Monongalia County is classified as attainment for all criteria pollutants. Thus, no review of this proposed project is required for applicability under Rule 19 (West Virginia's Non-attainment Permitting Rule) for this particular application. Therefore, this proposed project does not require a permit under PSD and/or Non-Attainment New Source Review.

The facility is currently classified as a major source of HAPs, which means the facility has the potential to emit 10 tons per year of a single HAP, which would be hydrogen chloride for this facility, or 25 tpy of total HAPs. Within the application, MEA has not elected to determine if this project would change the facility's major source status for HAPs.

Regardless, the MATS Rule (Subpart UUUUU – Nation Emission Standards for Hazardous Air Pollutants: Coal- and Oil- Fired Electric Utility Steam Generating Units) applies to major and area sources of Hazardous Air Pollutants (HAPs).

The main purpose of this project is to increase the level of acid gas control to meet the HCl or SO_2 standard of the MATS Rule while not increasing emissions of other pollutants. The two CFR boilers are coal fired EGUs, which were constructed in 1989. Thus, these units are classified as *existing coal-fired burning not low rank virgin coal*. The emission standards that MEA intents to comply with for the two CFB boilers from MATS is presented in following list.

- Filterable PM standard of 0.03 lb/MMBtu or 0.3 lb/MWh (gross electric output).
- SO_2 standard of 0.20 lb/MMBtu or 1.5 lb/MWh (gross electric output).
- Hg standard of 1.2 lb/TBtu (Trillion) or 0.013 lb/GWh (gross electric output).

MEA only needs to enhance the control efficiency of the inherent dry scrubber system for each CFB boiler to be capable of complying with the applicable acid gas (HCl or alternative SO_2) emission standards in the MATS Rule. MEA plans on demonstrating that these CFB boilers qualify as LEE units for filterable PM and mercury, which the past emission inventories for these unit supports. If MEA is successful in making these demonstrations, these source is not required to conduct the initial and continuous compliance demonstrations for the respective pollutant (See 40 CFR §§63.10000(c)(1)(i), (iii), (iv) and (vi)). For filterable PM, the source has to repeat this demonstration once every 3 years. MATS requires mercury LEE units to repeat this demonstration once every year. The demonstration for a PM LEE requires the sampling volume to be double for each run. For Hg LEE status, the source has to conduct a 30 operating day test.

If MEA is unsuccessful in demonstrating the units as a LEE units or lose their LEE status, then the requirements of initial and continuous compliance requirements are in effect. For filterable PM, the source would have to conduct one of the following continuous compliance options:

- Install and use PM continuous emission monitoring system (CEMS);
- PM Continuous Parameter Monitoring System (CPMS); or
- Quarterly PM testing.

For mercury, the source would have to conduct one of the following continuous compliance options:

- Install and use Hg CEMS; or
- Install and use Hg sorbent trap monitoring system;

For initial and continuous compliance with the SO_2 standard of MATS, MEA can utilize the current SO_2 CEMS minus the missing data procedures of Part 75.

These CFB boilers are currently and will remain subject to emission standards of Subpart Da to Part 60 for PM, which includes visible emissions, and SO_2; 45 CSR 2 for PM , which includes visible emissions; and 45 CSR 10 for SO_2. Currently, compliance for the sulfur dioxide and visible emissions standards in these regulations and rules is demonstrated through the use SO_2 CEMS and continuous opacity monitoring systems (COMS). Particulate matter (PM) is demonstrated through performance testing on a frequency established in 45 CSR §2A-5.2.

The only applicable regulation or rule that defines modification is Subpart Da. Subpart Da to Part 60 defines *modification* in the general provision of Part 60 as any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility. The proposed change in method of operation would increase fuel to the unit that would increase the potential of SO_2, which is needed to increase the SO2 removal of the control device that would decrease SO_2 emissions prior to being released to the atmosphere. Thus, this proposed change in method of operation does not meet the definition of modification of Part 60 and the current standards of Subpart Da remain as the enforceable standard, which is 0.60 lb of SO_2 per MMBtu and a 70% reduction efficiency of SO_2. The existing SO2 limit in the permit and in the MATS Rule is more stringent than the one in Subpart Da. Thus, the most stringent SO_2 would be the 0.20 lb per MMBtu from MATS and 94.8% SO_2 reduction requirement from Condition A(6) of Permit R14-0007C.

The auxiliary boilers are subject to the New Source Performance Standards of Subpart Db since each unit will have a design heat input rating of greater than 100 MMBtu/hr. Subpart Db establishes performance standards by pollutant by fuel type (i.e. coal, oil, and natural gas). For natural gas fired units, the subpart only establishes a performance standard for NO_x emissions. These units will be constructed after July 9, 1997 which makes the unit applicable to the limit in 40 CFR §60.44b(l) of 0.20 lb of NO_x (expressed as NO_2) per MMBtu. These units will be equipped with a low-NO_x burner with a maximum NO_x rate of 0.036 lb/MMBtu. At this NO_x rating, these units would have a margin of compliance of 18% of the applicable NO_x limit.

Subpart Db requires affected sources to demonstrate compliance with the NO_x limit on a 30 day rolling average. This subpart will require the use of a NO_x continuous emission monitoring system (NO_x CEMS) with a means to measure either O_2 or CO_2in the exhaust for demonstrating compliance with the NO_x emission standard. The application states that NO_x CEMS will be installed to meet the Part 75 monitoring requirements, which is applicable under 40 CFR §60.48b(b)(2).

The auxiliary boilers are subject to 40 CFR 63, Subpart DDDDD – National Emission Standard for Hazardous Air Pollutants (NESHAP) for Major Sources: Industrial Commercial, and Institutional Boilers and Process Heaters & the CFB boilers would be subject

This regulation establishes work practices as a means to comply with the emission standards (see Item 3 of Table 3 to Subpart DDDDD of Part 63). These boilers under Subpart DDDDD will be considered as new units. The one-time energy assessment is not required for new units. Therefore, the energy assessment is not applicable for these boilers and will not be included.

MEA prepared and submitted a complete application, paid the filing and NESHAP fees, and published a Class I Legal ad in the *Dominion Post* on November 23, 2015. The facility currently holds a valid Title V Operating Permit and included Attachment S of the application for a minor modification of this operating permit.

TOXICITY OF NON-CRITERIA REGULATED POLLUTANTS

The CFB boilers will not emit any pollutants that aren't already being emitted by these emission units at the facility. Therefore, no information about the toxicity of the hazardous air pollutants (HAPs) is presented in this evaluation.

AIR QUALITY IMPACT ANALYSIS

An air dispersion modeling study or analysis was not required, because the proposed modification does not meet the definition of a major modification of a major source as defined in 45CSR14.

MONITORING OF OPERATIONS

All the CFB and auxiliary boilers vent to a common stack before being released to the atmosphere. A Continuous Emissions Monitoring (CEM) system is used to measure sulfur dioxide, nitrogen oxides, and diluent gas (either O_2 or CO_2) and opacity is located at a common point to all four of the boilers venting to Stack 1. The MATs Rule, 40 CFR 63.10010(a)(3) allows affected unit(s) to utilize a common stack with non-affected unit(s). Thus, the use of the existing SO_2 CEMs is acceptable except that MEA must assign the calculated emission rate to each unit which includes the two auxiliary boilers.

The MATs Rule has several different monitoring options to demonstrate compliance with the PM and mercury standards. However, MEA has elected to demonstrate that the CFB boilers can qualify as a *low emitting emission* (LEE) units under the MATs Rule for PM and mercury in lieu of preforming the monitoring requirements for demonstrating continuous compliance with the standards for these two pollutants. A LEE unit must demonstrate that the unit is operating at less than 50% of the emission standard expect for mercury which is less than 10 percent of the allowable. For these two CFB boiler, the PM rate has to be less than 0.015 pounds per MMBTU (equates to less than 11.25 pounds per hour from Stack 1) and the mercury rate has to be less than 1.0 pounds per trillion Btu (equates to less than 0.00075 pounds per hour from Stack 1).

To qualify as a LEE unit, MEA will be required to conduct performance testing for PM using Method 5 but increase the minimum sample by a factor of 2. For a mercury LEE unit, MEA will be required to conduct a 30 boiler operating day performance test using Method 30B in Appendix A-8 to Part 60. To maintain LEE status under the MATs Rule, MEA will be required to repeat this testing once every 3 years for PM and once every year for mercury (40 CFR 63.10006(b)).

Under MATS, there are two definitions for start-up (paragraph 1 or paragraph 2). MEA plans on using the paragraph 1 definition and is required to record the information in 40 CFR §§63.10032(f)(1), (f)(3), and (f)(4). 40 CFR 63.10032(f)(2) applies to sources using the start-up in paragraph 2.

CHANGES TO PERMIT R13-1085B/R14-0007B

The current permit was written in an outdated format which is no longer being used by the DAQ. This writer recommends integrating the existing limits and conditions into the current format used by the agency today. Also, the DAQ no longer assigns permit applications a Rule 13 and R14 permit numbers for the same application. If the source has received a major source or major modification of a major source permit under Rule 14, then the R14 number remains for the permit number for that permit even if the source only is required to obtain a Rule 13 permit for the life of the facility. Thus, the Rule 13 permit number will be dropped from the permit number. A reference to the previous permits in Permit Conditions 2.4.1. and 2.5.1. will note the Rule 13 and Rule 14 permit numbers as listed on these originally issued permit.

Permit R13-1085B/R14-0007B included all four of the boilers and material handling activities. This writer recommends established one section (4.0.) to cover specific requirements for all of the boilers and another section (5.0.) for the material handling equipment associated with handling fuel, limestone, and flyash at the facility.

The following table is a listing of the existing conditions and corresponding new conditions numbers in the draft permit.

Table # 7 – Condition Key between R13-1058B/R14-0007B to R14-0007C		
Condition No. of R13-1058B/R14-0007B	Condition No. R14-0007C	Notes/Comments
A(1)	4.1.1. –PM; 4.1.2. -SO_2; 4.1.3. -NO_2; 4.1.4.-CO; 4.1.5. –VOC; 4.1.6. -Hg.	Other pollutants limits are exactly the same in A(3) which are only listed in 4.1.17.
A(2)	4.1.2.a	Included the existing table for the auxiliary boilers
A(3)	4.1.17.	Only incorporated mass limits. See following discussion
A(4)	5.1.1.	
A(5)	5.1.2.	
A(6)	4.1.1.b.ii.	Intergraded into the SO2 limit for the CFB boilers.
A(7)	3.1.7.	This section covers the whole facility.
A(8)	3.1.8.	This section covers the whole facility.
A(9)	3.1.9.	This section covers the whole facility.
B(1) Rule 2	4.1.1.a.i. & 4.1.3.k.	Rule 2 PM and opacity Standards
B(1) Rule 10	4.1.1.b.i	SO_2 limit
B(1) Subpart Da	4.1.1.b.i for SO2; 4.1.1.a.i. for PM; and 4.1.3.k. for opacity	Opacity limit in Rule 2 is more stringent than Subpart Da
B(1) Subpart Db	4.1.2.a.	Existing permitted limit is more stringent than Subpart Db

B(1) Method 9	Not necessary and omitted	B(1)(d), Subpart Da, and Rule 2 requires COMs.
B(1)(b)	Intergraded into 4.2.1.g and 4.3.1. as part of either the Test for PM LEE Status or PM Monitoring for MATS	MAT monitoring requirements are more stringent
B(1)(c)	4.1.1.b.ii., 4.2.1.a. SO2 CEMs and 4.2.2. as fired fuel monitoring system	Subpart Da allow the use of Part 75 CEMs in lieu of Part 60 CEMs minus the missing data procedures
B1(e)	5.1.3.	Fugitive PM Controls
B(1)(f)	4.5.1	Subpart Da reporting
B(1)(g)	Omitted	Subpart Da & Db Initial Notification
B(2)	4.2.1.b., h, and i.	NOx CEMs
B(5)	4.3.2.	CO Testing Requirements
B(4), B(6) though B(9)	These were appropriate test methods available at the time the original permit was issued. Omitted these conditions that list specific testing methods.	DAQ permit format requires test protocols be submitted prior to any compliance testing and the DAQ will determinate if the test method is acceptable or not at the time (See Condition 3.3.1.)

Conditions A(2), and A(3) were written for different operating scenarios in mind. A(2) was for only when the auxiliary boilers in operation while A(3) capped the total emissions when all four boilers were operating. Remember all four boilers release emissions to a common stack. A(1) sets mass rates for both of the CFB boilers, concentration limits and heat input limits for each CFB to meet. The same mass rate limits in A(1) are established in A(3) except for VOCs, and CO, which is the sum of the CO and VOCs limits for the CFB boilers (A(1)) and auxiliary boilers (A(2)).

The writer recommends omitting the mass rate limits from A(1) execpt for VOCs and CO; and establishing a total mass rate emission limit for the common stack based on the mass limits in A(3) regardless of which units are operating. This new condition (Condition 4.1.17) is replacing the other emission limits for the CFB boilers (A(1) & A(3)).

The applicable MATS requirements were add for the CFB boilers as well as Subpart DDDDD to Part 63 (Boiler MACT) for the auxiliary boilers. The auxiliary boilers are subject to only the tune-up provisions of Subpart DDDDD because the units are only natural gas fired boilers. These tune-ups must be conducted annually.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application indicates the proposed modification of the facility will meet all the requirements of the applicable rules and regulations when operated in accordance with the permit application. Therefore, the writer recommends granting Morgantown Energy Associates a Rule 13 modification permit for their facility located in Morgantown, WV.

Edward S. Andrews, P.E.
Engineer

March 3, 2016
Date

Andrews, Edward S

From: Patrick E. Ward <PEWard@potesta.com>
Sent: Thursday, March 03, 2016 1:15 PM
To: Andrews, Edward S
Cc: Todd Shirley; Manley, Josh
Subject: RE: 061-00027_PERM_R14-0007C-predraft.docx

Ed, regarding your question about road dust emissions control, the method is listed in the permits as paved and cleaning by appropriate measures. The method of cleaning that is listed in the Title V permit is water cleaning.

Let us know if you need anything else regarding this issue.

Regards,
Patrick Ward
Potesta & Associates, Inc.
7012 MacCorkle Avenue, S.E.
Charleston, West Virginia 25304
Ph: (304) 342-1400
Direct: (304) 414-4751
Fax: (304) 343-9031

ID # 61-27
Reg R14-0007C
Company MEA
Facility Morgantown Initials ESA

From: Andrews, Edward S [mailto:Edward.S.Andrews@wv.gov]
Sent: Wednesday, February 17, 2016 4:04 PM
To: 'tshirley@ppmsllc.com' <tshirley@ppmsllc.com>
Cc: Patrick E. Ward <PEWard@potesta.com>; Dan Traynor (dtraynor@ppmsllc.com) <dtraynor@ppmsllc.com>
Subject: 061-00027_PERM_R14-0007C-predraft.docx

Mr. Shirley: I have attached a pre-draft of R14-0007C for your staff to review. Please use Word's Track Changes feature in noting errors/suggestions/comments. After Bev has finish her review, I will contact you to see if MEA has any input to improve the draft before public comment.

I noticed that that fugitive emissions calculation in Attachment N of your application for road dust emissions used a 50% control efficiency. However, the actual control measure was not listed. Please identify the control measure that corresponds to the 50% removal (control) efficiency used in the fugitive dust calculations.

Should you have any questions about this email or your application, please contact me.

Sincerely,

Edward S. Andrews, P.E.
Engineer
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE

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Andrews, Edward S

From: Patrick E. Ward <PEWard@potesta.com>
Sent: Wednesday, March 02, 2016 2:13 PM
To: Andrews, Edward S
Subject: RE: Updated Predraft for Permit Application R14-0007C
Attachments: 061-00027_PERM_R14-0007C-draft3_1_16_MEA Comments.pdf

PDF Printer Version, let me know if you have notice of a virus in this.

ID # 061-27
Reg R14-0007C
Company MEA
Facility Morgantown Initials ESA

Regards,
Patrick Ward
Potesta & Associates, Inc.
7012 MacCorkle Avenue, S.E.
Charleston, West Virginia 25304
Ph: (304) 342-1400
Direct: (304) 414-4751
Fax: (304) 343-9031

This electronic communication and its attachments contain confidential information. The recommendations and/or design data included herein are provided as a matter of convenience and should not be used for final design or ultimate decision making. Rely only on the final hardcopy materials bearing the consultant's original signature and seal. If you have received this information in error, please notify the sender immediately.

From: Patrick E. Ward
Sent: Wednesday, March 02, 2016 1:58 PM
To: 'Andrews, Edward S' <Edward.S.Andrews@wv.gov>; 'tshirley@ppmsllc.com' <tshirley@ppmsllc.com>; Dan Traynor (dtraynor@ppmsllc.com) <dtraynor@ppmsllc.com>
Cc: Shimshock, John <John.Shimshock@nrg.com>; Tephabock, Brian S <Brian.S.Tephabock@wv.gov>; McKeone, Beverly D <Beverly.D.Mckeone@wv.gov>; 'Manley, Josh' <Josh.Manley@nrg.com>
Subject: RE: Updated Predraft for Permit Application R14-0007C

Mr. Andrews,

Attached are a few comments on the updated pre-draft permit.

Entire Document
NON-CONFIDENTIAL

Regards,
Patrick Ward
Potesta & Associates, Inc.
7012 MacCorkle Avenue, S.E.
Charleston, West Virginia 25304
Ph: (304) 342-1400
Direct: (304) 414-4751
Fax: (304) 343-9031

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From: Andrews, Edward S [mailto:Edward.S.Andrews@wv.gov]
Sent: Tuesday, March 01, 2016 4:21 PM
To: 'tshirley@ppmsllc.com' <tshirley@ppmsllc.com>; Dan Traynor (dtraynor@ppmsllc.com) <dtraynor@ppmsllc.com>
Cc: Patrick E. Ward <PEWard@potesta.com>; Shimshock, John <John.Shimshock@nrg.com>; Tephabock, Brian S

<Brian.S.Tephabock@wv.gov>; McKeone, Beverly D <Beverly.D.Mckeone@wv.gov>
Subject: Updated Predraft for Permit Application R14-0007C

Mr. Shirley: Attached is a revised pre-draft for you and your staff to review based on our discussions earlier today.

Should you have any questions, please contact me.

Sincerely,

Edward S. Andrews, P.E.
Engineer
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
304.926.0499 ext. 1214

West Virginia Department of Environmental Protection

Earl Ray Tomblin
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Permit to Modify

R14-0007C

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 C.S.R. 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:

Morgantown Energy Associates
Morgantown Energy Facility
061-00027

William F. Durham
Director

Issued: DRAFT

This permit will supercede and replace Permit R13-1058B/R14-0007B.

Facility Location:	555 Beechurst Avenue Morgantown, Monongalia County, West Virginia 26505
Mailing Address:	Same as above
Facility Description:	Fossil Fuel Fired Cogeneration Facility
NAICS Codes:	221112
UTM Coordinates:	589.20 km Easting • 4,388.10 km Northing • Zone 17
Permit Type:	Modification
Description of Change:	This action is for the change in method of operation for the two fluidized bed boilers to permit the installation and subsequent operation of the SNCR systems on both CFB boilers. This action also addresses the requirements pursuant to 40 ~~CFFR~~ CFR 63 Subpart UUUUU (Mercury and Air Toxics Rule, MATS).

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Table of Contents

1.0. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S001A	Vents 1 & 2	Elevating Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001B	Vents 1 & 2	TP001B – Elevating Conveyor1 to Reversible Feed Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001C	Vents 1 & 2	Reversible Feed Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001D	Vent 1	TP001D - Reversible Feed Conveyor 1 to Coal Silo 1	1989	500 TPH	ES 1/BH 1
S001E	Vent1	Coal Silo 1	1989	2,100 Tons	ES 1 / BH 1
S001F	Vents 1 & 2	TP001F - Elevating Conveyor 1 to Emergency Bypass Conveyor	2001	120 TPH	ES 1 / BH 1 & 2
S002A	Vent 2	TP002A - Reversible Feed Conveyor 1 to Gob Storage Silo 1	1989	500 TPH	ES 1 / BH 2
S002B	Vent 2	Gob Storage Silo 1	2001	2,100 Tons	ES 1 / BH 2
S003A	Vent 3	TP003A – Coal Silo 1 to Weigh Belt Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003B	Vent 3	TP003B – Gob Storage Silo 1 to Weigh Belt Conveyor 2	1989	60 TPH	ES 2 / BH 3
S003C	Vent 3	Weigh Belt Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003D	Vent 3	Weigh Belt Conveyor 2	2001	60 TPH	ES 2 / BH 3
S003E	Vent 3	TP003E - Weigh Belt Conveyor 1& 2 to Grinding Mill	1989	60 TPH	ES 2 / BH 3
S003F	Vent 3	TP003F - Weigh Belt Conveyor 1& 2 to Hammer Mill	1989	60 TPH	ES 2 / BH 3
S003G	Vent 3	TP003G – Emergency Mill Feed System Hopper 1 to En-mass Elevating Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003H	Vent 3	En-mass Elevating Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003I	Vent 3	TP003I – En-mass Elevating Conveyor 1 to Mill Inlet Chute System	1989	60 TPH	ES 2 / BH 3
S003J	Vent 3	Grinding Mill 1	1989	60 & 90 TPH	ES 2 / BH 3
S003K	Vent 3	Hammer Mill 1	1989	60 TPH	ES 2 / BH 3

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S004A	Vent 4	TP004A – Grinding Mill 1 to Mill Collecting Conveyor 1	1989	60 & 90 TPH	ES 3 / BH 4
S004B	Vent 4	TP004B – Hammer Mill 1 to Mill Collecting Conveyor 1	1989	60 TPH	ES 3 / BH 4
S004C	Vent 4	TP004C – Baghouse 4 Dust Discharge to Mill Collecting Conveyor 1	1989	5 TPH (est.)	ES 3 / BH 4
S004D	Vent 4	Mill Collecting Conveyor 1	2001	120 TPH	ES 3 / BH 4
S004E	Vent 4	TP004E – Mill Collecting Conveyor 1 to Elevating Conveyor 2	1989	120 TPH	ES 3 / BH 4
S004F	Vent 4	TP004F – Baghouse 3 Dust Discharge to Mill Collecting Conveyor 1	1989	12 TPH	ES 3 / BH 4
S004G	Vent 4	Elevating Conveyor 2 (Bottom Half)	2001	120 TPH	ES 3 / BH 4
S005A	Vent 5	Elevating Conveyor 2 (Top Half)	1989	120 TPH	ES 4 / BH 5
S005B	Vent 5	TP005B – Elevating Conveyor 2 to Fuel Bin 1	1989	120 TPH	ES 4 / BH 5
S005C	Vent 5	TP005C – Elevating Conveyor 2 to Fuel Bin 2	1989	120 TPH	ES 4 / BH 5
S005D	Vent 5	Fuel Bin 1	1989	375 Tons	ES 4 / BH 5
S005E	Vent 5	Fuel Bin 2	1989	375 Tons	ES 4 / BH 5
S005F	Vent 5	Emergency Bypass Conveyor	2001	120 TPH	ES 4 / BH 5
Limestone Handling					
S006A	Vent 6	TP006A – Transfer from Truck to Limestone Unloading Hopper 1	1989	37.5 TPH	BE 2 / BH 6
S006B	Vent 6	TP006B – Transfer from Truck to Limestone Unloading Hopper 2	1989	37.5 TPH	BE 2 / BH 6
S006C	Vent 6	Limestone Unloading Hopper 1	1989	75 TPH	BE 2 / BH 6
S006D	Vent 6	Limestone Unloading Hopper 2	1989	75 TPH	BE 2 / BH 6
S007A	Vent 7 & 8	TP007A – Transfer from Limestone Unloading Hopper 1 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S007B	Vent 7 & 8	TP007B – Transfer from Limestone Unloading Hopper 2 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S007C	Vent 7 & 8	TP007C – Transfer from Truck to Pneumatic Conveying System 1	1989	75 TPH	PCS 1

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S007D	Vent 7	TP007D – Transfer from Pneumatic Conveying System 1 to Limestone Silo 1	1989	75 TPH	ES 5 / BVF 1
S007E	Vent 7	Limestone Silo 1	1989	1,160 Tons	ES 5 / BVF 1
S008A	Vent 8	TP008A – Transfer from Limestone Silo 1 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S008B	Vent 8	TP008B – Transfer from Pneumatic Conveying System 1 to Limestone Bin 1	1989	75 TPH	ES 6 / BVF 2
S008C	Vent 8	Limestone Bin 1	1989	250 Tons	ES 6 / BVF 2
S008D	Vent 8	TP008D– Limestone Bin 1 to Gravimetric Feeder/Conveyor A	1989	10 TPH	ES 6 / BVF 2
S008E	Vent 8	Gravimetric Feeder/Conveyor A	1989	10 TPH	ES 6 / BVF 2
S008F	Vent 8	TP008F– Gravimetric Feeder/Conveyor A to Rotary Valve A	1989	10 TPH	ES 6 / BVF 2
S008G	Vent 8	TP008G– Limestone Bin 1 to Gravimetric Feeder/Conveyor B	1989	10 TPH	ES 6 / BVF 2
S008H	Vent 8	Gravimetric Feeder/Conveyor B	1989	10 TPH	ES 6 / BVF 2
S008I	Vent 8	TP008I– Gravimetric Feeder/Conveyor B to Rotary Valve B	1989	10 TPH	ES 6 / BVF 2
Boiler & Associated Equipment					
S009A	STACK 1	TP009A - Limestone Feeder Rotary Valve A to Pneumatic Conveying System 2	1989	10 TPH	PCS / BH 7 & 8
S009B	STACK 1	TP009B - Limestone Feeder Rotary Valve B to Pneumatic Conveying System 2	1989	10 TPH	PCS / BH 7 & 8
S009C	STACK 1	TP009C - Pneumatic Conveying System 2 to CFB Boiler 1	1989	10 TPH	PCS / BH 7 & 8
S009D	STACK 1	TP009D - Pneumatic Conveying System 2 to CFB Boiler 2	1989	10 TPH	PCS / BH 7 & 8
S009E	STACK 1	TP009E – Fuel Bin 1 to Enclosed Conveying System 7	1989	46 TPH	ES / BH 7 & 8
S009F	STACK 1	TP009F – Fuel Bin 2 to Enclosed Conveying System 7	1989	46 TPH	ES / BH 7 & 8
S009G	STACK 1	Enclosed Conveying System 7 to CFB Boiler 1	1989	46 TPH	ES / BH 7 & 8

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S009H	STACK 1	Enclosed Conveying System 7 to CFB Boiler 2	1989	46 TPH	ES / BH 7 & 8
S009J	STACK 1	Ahlstrom Pyroflow CFB Boiler/Cyclone #1	1989, SNCR 2016	375 MMBtu/hr	Limestone Injection, BH 8 & SNCR
S009K	STACK 1	Ahlstrom Pyroflow CFB Boiler/Cyclone #2	1989, SNCR 2016	375 MMBtu/hr	Limestone Injection, BH 7 & SNCR
S009L	STACK 1	Zurn Auxiliary Boiler #1	1989	132 MMBtu/hr	LNB
S009M	STACK 1	Zurn Auxiliary Boiler #2	1989	132 MMBtu/hr	LNB
Ash Handling					
S010A	Vent 9	TP010A – CFB Boiler 1 Bottom Ash Screw A to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010B	Vent 9	TP010C – CFB Boiler 1 Bottom Ash Screw B to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010C	Vent 9	TP010E – CFB Boiler 1 Bottom Ash Screw C to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010D	Vent 9	Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010E	Vent 9	TP010I – CFB Boiler 2 Bottom Ash Screw A to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010F	Vent 9	TP010K – CFB Boiler 2 Bottom Ash Screw B to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010G	Vent 9	TP010M – CFB Boiler 2 Bottom Ash Screw C to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010H	Vent 9	Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010I	Vent 9	TP010Q – Drag Chain Conveyor 101 to Clinker Grinder 1	1989	16.5 TPH	ES 8 / BVF 3
S010J	Vent 9	TP010S – Drag Chain Conveyor 201 to Clinker Grinder 3	1989	16.5 TPH	ES 8 / BVF 3
S010K	Vent 9	Clinker Grinder 1	1989	16.5 TPH	ES 8 / BVF 3
S010L	Vent 9	Clinker Grinder 3	1989	16.5 TPH	ES 8 / BVF 3

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S010M	Vent 9	TP010Y – Clinker Grinder 1 to Bottom Ash Holding Bin 1	1989	16.5 TPH	ES 8 / BVF 3
S010N	Vent 9	TP010AA – Clinker Grinder 3 to Bottom Ash Holding Bin 1	1989	16.5 TPH	ES 8 / BVF 3
S010O	Vent 9	Bottom Ash Holding Bin	1989	76.5 Tons	ES 8 / BVF 3
S011A	Vent 10	TP011A – Bottom Ash Holding Bin Discharge A to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011B	Vent 10	TP011B – Bottom Ash Holding Bin Discharge B to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011C	Vent 10	TP011C – Bottom Ash Holding Bin Discharge C to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011D	Vent 10	TP011D – CFB No. 1 Air Heater Hopper to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011E	Vent 10	TP011E – CFB No. 2 Air Heater Hopper to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011F	Vent 10	TP011F – CFB No. 1 Baghouse Row 1 Discharge to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011G	Vent 10	TP011G – CFB No. 1 Baghouse Row 2 Discharge to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011H	Vent 10	TP011H – CFB No. 2 Baghouse Row 1 Discharge to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011I	Vent 10	TP011I – CFB No. 2 Baghouse Row 2 Discharge to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011J	Vent 10	Filter/Separator A Exhaust	1989	50 TPH	ES 3 / VCS A / FS A
S011K	Vent 10	Filter/Separator B Exhaust	1989	50 TPH	ES 3 / VCS B / FS B
S011L	Vent 10	Filter/Separator C Exhaust	1989	50 TPH	ES 3 / VCS C / FS C
S012A	Vent 11	TP012A – Filter/Separator A to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012B	Vent 11	TP012B – Filter/Separator B to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012C	Vent 11	TP012C – Filter/Separator A to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012D	Vent 11	Ash Silo1	1989	1,300 Tons	ES 9 / BH 9

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S012E	Vent 11	TP012E – Ash Silo to Truck	1989	300 TPH	BH 9 / BE 4 / AC 1
S012F	Vent 11	TP012FE – Ash Silo to Truck	1989	300 TPH	BH 9 / BE 4 / AC 2
Fuel Receiving & Emergency Fuel Feed Fugitives					
S00F1	Fugitive Emission 1	TP00F1 – Transfer from Truck to Fuel Unloading Hopper/Vibratory Feeder 1	1989	250 TPH	BE 1 / WS 1
S00F2	Fugitive Emission 2	Fuel Unloading Hopper 1	1989	250 TPH	BE 1 / WS 1
S00F3	Fugitive Emission 3	Vibratory Feeder 1	1989	250 TPH	BE 1 / ES 1
S00F4	Fugitive Emission 4	TP00F4 – Transfer from Truck to Fuel Unloading Hopper/Vibratory Feeder 2	1989	250 TPH	BE 1 / WS 2
S00F5	Fugitive Emission 5	Fuel Unloading Hopper 2	1989	250 TPH	BE 1 / WS 2
S00F6	Fugitive Emission 6	Vibratory Feeder 2	1989	250 TPH	BE 1 / ES 1
S00F7	Fugitive Emission 7	TP00F7 – Vibratory Feeder 2 to Transfer Conveyor 1	1989	250 TPH	BE 1 / ES 1 / WS 3
S00F8	Fugitive Emission 8	TP00F8 – Vibratory Feeder 1 to Transfer Conveyor 1	1989	250 TPH	BE 1 / ES 1 / WS 4
S00F9	Fugitive Emission 9	Transfer Conveyor 1	1989	500 TPH	BE 1 / ES 1
S00F10	Fugitive Emission 10	TP00F10 – Transfer Conveyor 1 to Elevating Conveyor 1	1989	500 TPH	BE 1 / ES 1 / WS 5
S00F11	Fugitive Emission 11	TP00F11 – Dribble Chute 1 to Dribble Chute Catch Bin 1	1989	N/A	BE 1
S00F12	Fugitive Emission 12	Dribble Chute Catch Bin 1	1989	N/A	BE 1
S00F13	Fugitive Emission 13	TP00F13 – Dribble Chute Catch Bin 1 to Dribble Chute Conveyor 1	1989	N/A	BE 1
S00F14	Fugitive Emission 14	TP00F14 – Dribble Chute Conveyor 1 to Transfer Conveyor 1	1989	N/A	BE 1

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S00F15	Fugitive Emission 15	TP00F15 – Front End Loader to Emergency Mill Feed System Hopper 1	1989	60 TPH	N/A
S00F16	Fugitive Emission 16	Emergency Mill Feed System Hopper 1	1989	60 TPH	N/A

[1] AC – Ash Conditioner; BH – Baghouse; BE – Building Enclosure; BVF – Bin Vent Filter; ES – Enclosed System; FS – Filter Separator; LNB – Low NO_x Burners; , SNCR – Selective Non-catalytic Reduction System, PCS – Pneumatic Conveying System; VCS – Vacuum Conveying System; WS – Water Spray.

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments	**NO_x**	Nitrogen Oxides
CBI	Confidential Business Information	**NSPS**	New Source Performance Standards
CEM	Continuous Emission Monitor	**PM**	Particulate Matter
CES	Certified Emission Statement	**$PM_{2.5}$**	Particulate Matter less than 2.5 µm in diameter
C.F.R. *or* CFR	Code of Federal Regulations	**PM_{10}**	Particulate Matter less than 10µm in diameter
CO	Carbon Monoxide	**Ppb**	Pounds per Batch
C.S.R. *or* CSR	Codes of State Rules	**Pph**	Pounds per Hour
DAQ	Division of Air Quality	**Ppm**	Parts per Million
DEP	Department of Environmental Protection	**Ppmv or ppmv**	Parts per Million by Volume
dscm	Dry Standard Cubic Meter	**PSD**	Prevention of Significant Deterioration
FOIA	Freedom of Information Act	**Psi**	Pounds per Square Inch
HAP	Hazardous Air Pollutant	**SIC**	Standard Industrial Classification
HON	Hazardous Organic NESHAP	**SIP**	State Implementation Plan
HP	Horsepower	**SNCR**	Selective Non-catalytic Reduction
lbs/hr	Pounds per Hour	**SO_2**	Sulfur Dioxide
LDAR	Leak Detection and Repair	**TAP**	Toxic Air Pollutant
M	Thousand	**TPY**	Tons per Year
MACT	Maximum Achievable Control Technology	**TRS**	Total Reduced Sulfur
MDHI	Maximum Design Heat Input	**TSP**	Total Suspended Particulate
MM	Million	**TBtu**	Trillion British Thermal Units
MMBtu/hr *or* mmbtu/hr	Million British Thermal Units per Hour	**USEPA**	United States Environmental Protection Agency
MMCF/hr *or* mmcf/hr	Million Cubic Feet per Hour	**UTM**	Universal Transverse Mercator
NA	Not Applicable	**VEE**	Visual Emissions Evaluation
NAAQS	National Ambient Air Quality Standards	**VOC**	Volatile Organic Compounds
NESHAPS	National Emissions Standards for Hazardous Air Pollutants	**VOL**	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*;

2.3.2. 45CSR14 – *Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration;*

2.4. Term and Renewal

2.4.1. This permit supersedes and replaces previously issued Permit R13-~~[####].~~ -1058B/R14-0007B. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule;

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-~~[####],~~ -1058/R14-007, R13-1058B/R14-0007B, R14-0007C, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.11 and 10.3.]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies; i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by

improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5 The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60th) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1.]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] ***[State Enforceable Only]***

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.1.7. All plant roads and haulways shall be paved and shall be kept clean by appropriate measures to minimize the emissions or entrainment of fugitive particulate matter.
[45 CSR §2-5.1.]

3.1.8. There shall be no open stockpiling of coal or coal refuse at the permitting facility.
[45 CSR §2-5.1.a.]

3.1.9. All trucks delivering coal or coal refuse and trucks removing ash from the facility shall be fully covered or enclosed.
[45 CSR §§2-5.1. & 5.1.b.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

1. The permit or rule evaluated, with the citation number and language;
2. The result of the test for each permit or rule condition; and,
3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State Enforceable Only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class with postage prepaid to the address(es) set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

If to the DAQ:	**If to the US EPA:**
Director WVDEP Division of Air Quality 601 57th Street Charleston, WV 25304-2345	Associate Director Office of Air Enforcement and Compliance Assistance (3AP20) U.S. Environmental Protection Agency Region III 1650 Arch Street Philadelphia, PA 19103-2029

3.5.4. Operating Fee

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements for the Boilers (CFB and Auxiliary Boilers)

4.1. Limitations and Standards

4.1.1. Particulate Matter (PM) emissions emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. PM emission rate shall not exceed 0.03 lb/MMBtu of heat input on a 30 day rolling average.
[45 CSR §2-4.1.b., and 40 CFR §60.42Da(a)]

b. PM concentration of no greater than 0.016 grains per dscf corrected to 3.5 percent oxygen.

c. Effective April 16, 2016, filterable PM emission rate shall ~~next~~ not exceed 0.03 lb/MMBtu or 0.30 lb/MWh (gross basis) on a 30 boiler operating day rolling average.
[40 CFR §63.10005(a) Row 1a of Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs]

4.1.2. Sulfur Dioxide (SO_2) emissions emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. SO_2 emission rate shall not exceed 0.40 lb/MMBtu on a 30 day rolling average.
[40 CFR §60.43Da(a)(2)]

b. The SO_2 reduction efficiency from each unit shall not be less than 94.6% on a 30-day rolling ~~basis~~average.
[40 CFR §60.43Da(a)(2)]

c. Effective April 16, 2016, the SO_2 emission rate shall not exceed 0.20 lb/MMBtu or 1.5 lb/MWh (gross basis) on a 30 boiler operating day rolling average.
[40 CFR §§63.9991(c), §63.10005(a)(2)(i), Row 1b of Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs, 45 CSR §10-3.1.]

d. The permittee shall operate a dry flue gas desulfurization system for the unit at all times consistent with 40 CFR §63.10000(b). Compliance with is requirement is satisfied through the use limestone injection into the CFB boilers coupled with the fabric filter collection system.
[40 CFR §63.9991(c)(2)]

4.1.3. Emissions of nitrogen oxides (~~expressed as NO_2~~NO_x), expressed as NO_2, emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. NO_x concentration shall not exceed 293 ppmvd corrected to 3 % oxygen on a 24-hr average basis.

b. NO_x emission rate shall not exceed 0.40 lb of ~~NO_2~~ NO_x per MMBtu on a 30 day rolling ~~basis~~average.

c. The permittee shall operate the SNCR in such manner to maintain compliance with ~~above~~ the above NO_x limits and in Condition 4.1.17.

4.1.4. Emissions of carbon monoxide (CO) emitted to the atmosphere from each of the CFB boilers shall not exceed the following limits to the corresponding averaging periods.

a. CO concentration shall not exceed 188 ppmvd corrected to 3 % oxygen on a 24-hr average basis.

b. CO emissions rate shall not exceed 0.157 lb/MMBtu.

4.1.5. Emissions of volatile organic compounds (VOC) emitted to the atmosphere from each of the CFB boilers shall not exceed 0.0074 lb/MMBtu.

4.1.6. Emissions of mercury (Hg) emitted to the atmosphere from each CFB boiler shall not exceed 1.2 lb/~~TBTU~~ TBtu or 0.013 lb/GWh (gross basis) based on a thirty (30) boiler operating day rolling average.
[40CFR§§63.9991(a)(1); Row 1c of Table 2 to Subpart UUUUU of Part 63; §63.10000(a); and §63.10010(g)]

4.1.7. At all times, the permittee must operate and maintain each CFB boiler, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
[40 CFR §63.10000(b)]

4.1.8. The permittee shall conduct a tune-up of the burner and combustion controls of each CFB boiler at least once every 36 calendar months in accordance with the following:

a. The permittee must perform an inspection of the burner at least once every 36 calendar months. The permittee may delay the first burner inspection until the next scheduled unit outage provided the permittee meet the requirements of 40 CFR §63.10005.

b. As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

i. Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection;

ii. Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator.

c. As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

d. As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

e. As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

f. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

g. Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add- on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

h. While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_x and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continuous values before and after each optimization adjustment made by the system.
[40 CFR §63.9991(a)(1), Row 1 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards, 40 CFR 10021(e)]

4.1.9. During startup and shut down operations, the permittee must operate all continuous monitoring systems associated with the CFB boilers.
[40 CFR 63.10000(a), Rows 3 & 4 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

4.1.10. For startup of each CFB boiler, the permittee shall use natural gas to the maximum extent possible throughout the startup period. The permittee shall operate the associated PM control device for the unit within one hour of adding coal to the unit.
[40 CFR 63.10000(a), Row 3 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

4.1.11. During shutdown of each CFB boiler, the permittee shall operate all applicable control devices and continue to operate those control devices after the cessation of coal fuel being feed into the units and for as long as possible thereafter considering operational and safety concerns.
[40 CFR 63.10000(a), Row 4 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

4.1.12. If the permittee elects to demonstrates compliance with PM and/or Hg emissions limit of Condition 4.1.1.c. and/or Condition 4.1.6, respectively, through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan in accordance with Conditions 3.5.1. at least 60 days before the initial performance evaluation (where applicable) of the CMS. The site-specific monitoring plan shall include the information specified in 40 CFR 63.10000(d)(5)(i)

through (d)(5(vii). The permittee must operate and maintain the CMS according to the site-specific monitoring plan.
[40 CFR §§63.10000(d)(1), (d)(2) and (d)(4)]

4.1.13. Before October 13, 2016, the permittee shall either demonstrate initial compliance of the filterable particulate matter (PM) standard (Condition 4.1.1.c.) or demonstrate that the CFB boilers qualify as a low emitting EGU (LEE) for filterable PM in accordance with 40 CFR 63.10005(h).
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(iv)]

4.1.14. Before October 13, 2016, the permittee shall demonstrate initial and continuous compliance of the applicable hydrogen chloride (HCl) standard in Subpart UUUUU to Part 63 or the alternative to the HCl standard, which is the SO_2 standard (Condition 4.1.2.c), using SO_2 CEMS in accordance with Condition 4.2.1.
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(v)]

4.1.15. Before October 13, 2016, the permittee shall demonstrate initial compliance of the mercury standard of 40 CFR §63.10005(a) (Condition 4.1.6.) or demonstrate that the CFB boilers qualify as a low emitting EGU (LEE) for mercury in accordance with 40 CFR 63.10005(h).
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(vi)]

4.1.16. The following conditions and requirements are specific to the auxiliary boilers (ID S009L and S009M):

a. During those periods when neither of the two fluidized bed boilers are in operation but steam demand for the West Virginia University requires operation of either or both of the gas-fired auxiliary boilers, emission from the common stack shall not exceed the emission limits in Table 4.1.16.a.

Table 4.1.16.a. Emission Limits for the Auxiliary Boilers		
Pollutant	lb/hr	lb/MMBtu
Particulate Matter (PM)	1.20	0.0045
Sulfur Dioxide (SO_2)	0.14	5.3 X10^{-4}
Nitrogen Oxides (NO_x)	50	0.189*
Volatile Organic Compounds (VOC)	1.95	0.0074
Carbon Monoxide (CO)	10	0.038

* Emission limit shall be demonstrated on a 30 day rolling average basis. **[40 CFR §60.44b(i)]**

b. The permittee shall conduct annual tune-ups of each boiler once every year in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. Subsequent tune-ups shall be conducted no later than 13 months from previous tune-up. If the unit is not operating on the required date for a tune-up, then the tune-up must be conducted within 30 calendar days of re-startup. These tune-ups shall consist of the following:

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment, but each burner must be inspected at least once every 12 months;

ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown);

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, which includes the verifying or ensure the manufacturer's NO_x concentration specification are maintained;

v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).
[40 CFR §§63.7500(a)(1) & (c); §63.7505(a); §63.7510(e); §63.7515(d); §§63.7540(a)(10), (11) & (12); and Table 3 to Subpart DDDDD of Part 63—Work Practice Standards]

4.1.17. During periods when the CFB boilers are operation, the emissions from Stack 1 shall not exceed the following emission limitation:

a. Particulate matter emission shall not exceed 22.5 pounds per hour.

b. Sulfur dioxide emission shall not exceed 285 pounds per hour on a 24-hour average basis.

c. Nitrogen oxides (NO_x) emission shall not exceed 300 pounds per hour on a 24-hours average basis.

d. Carbon monoxide (CO) emissions shall not exceed 117.5 pounds per hour ~~expect~~ except when CFB boiler(s) are in operation with the auxiliary boiler(s) then the ~~VOC~~ CO emission rate shall not exceed 127.5 pounds per hour.

e. Volatile organic compounds (VOC) emissions shall not exceed 5.55 pounds per hour ~~expect~~ except when the CFB boiler(s) are in operation with the auxiliary boiler(s) then the VOC emission rate shall not exceed 7.5 pounds per hour.

f. Lead emissions shall not exceed 0.13 pound per hour.

g. Mercury emissions shall not exceed 0.021 lb/hr

h. Fluorides emissions shall not exceed 0.4 pounds per hour.

i. Beryllium emissions shall not exceed 0.0002 pounds per hour.

j. Arsenic emissions shall not exceed 0.002 pounds per hour.

k. Radionuclides emissions shall not exceed 0.0009 pounds per hour.

l. Visible emissions shall not exceed 10% opacity based on a six minute average.
[45 CSR §2-3.1. and 40 CFR §60.42Da(b)]

4.1.18. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.11.]

4.2. Monitoring Requirements

4.2.1. *Continuous Monitoring Requirements:* The permittee shall install, calibrate, maintain and operate CEMS, continuous opacity monitor (COMS) and a diluent monitor to measure and record the emissions of SO_2, NO_x, and other parameters to determine compliance from the CFB boilers and the auxiliary boilers venting through Stack 1 in a manner sufficient to demonstrate continuous compliance with the SO_2 and NO_x emission standards in Condition 4.1.2~~1~~, 4.1.3, and 4.1.16.~~-and Condition 4.1.2.~~ Such records of this monitoring system, data collected, and calculated values shall be maintained in accordance with Condition 3.2.1. These systems shall be installed, calibrated, properly functioning, and certified in accordance with the following requirements:

a. *SO_2 CEMS:* The SO_2 CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75 provided that the requirements of 40 CFR §60.49a(b(4)(i – iii) are met. Record keeping and reporting shall be conducted pursuant Subpart F and G in 40 CFR 75. **[40 CFR §60.49a(b)(4) and 45 CSR §10-8.2.c.1.]**

i. For each hour in which valid data are obtained for all parameters, the permittee must calculate the SO2 emission rate and the calculated pollutant emission rate to each unit that shares the common stack, which is Stack 1 for CFB #1, CFB #2, and both auxiliary boilers.
[40 CFR §63.10010(a)(3)(B)]

ii. For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in Sections 2.1 through 2.3 of Appendix B to Part 75 of Chapter 40, with the following addition: The permittee must perform the linearity checks required in Section 2.2 of Appendix B to Part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.
[40 CFR §60.49Da(b)(3) and 40 CFR §63.10010(f)(2)]

iii. Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.
[40 CFR §63.10010(f)(3)]

iv. Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the Part 75 SO_2 data and do not use Part 75 substitute data values. For startup or shutdown hours (as defined in 40 CFR §63.10042) the default electrical load and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in 40 CFR §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO_2 emission rate for any of these hours.
[40 CFR §60.49Da(b)(4)(iii) and 40 CFR §63.10010(f)(4)]

b. *NO_x CEMS:* The NO_x CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75.

For use of NO_x CEMS used to demonstrate compliance for the auxiliary boilers (S009L and S009M), the permittee shall also meet the requirements of 40 CFR §60.49b. Data reported to meet the requirements of 40 CFR §60.49b for the auxiliary boilers shall not include data substituted using the missing data procedures in Subpart D of Part 75 of Chapter 40, nor shall the data have been bias adjusted according to the procedures of Part 75 of Chapter 40.
[40 CFR §60.48b(b)(2)]

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where SO_2 and NO_x are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
[40 CFR §60.49Da(b)(4)(i) and 40 CFR §60.48b(b)(1)]

i. If the permittee use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of emissions limit in Conditions 4.1.1.b.i., the O2 or CO2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The permittee must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.
[40 CFR §§6310010(b)]

d. *Flow Monitor:* The volumetric flow rate of the flue gas shall be monitored at the location where SO_2 and NO_x are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
[40 CFR §60.49Da(m)]

e. *COMS:* Exhaust gas opacity from Stack 1 shall be monitored using a continuous opacity monitoring system for the purpose of demonstrating compliance with Condition 4.1.3.k. The permittee shall install calibrate, maintain, and operate the COMS in accordance with Performance Specification (PS) 1 in 40 CFR Part 60, Appendix B.
[40 CFR §§60.49Da(a) and (a)(1), 45 CSR §2-8.2.a.1., and 45 CSR §2A-6.2.]

f. *Hg CEMS or sorbent trap monitoring system:* The permittee must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with Appendix A to Subpart UUUUU of Part 63, Chapter 40 if both CFB boilers do not qualify as a LEE unit for Hg in accordance with 40 CFR 63.10005(h). The permittee must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A to Subpart UUUUU of Part 63, Chapter 40, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A to Subpart UUUUU of Part 63, Chapter 40 explains how to reduce sorbent trap monitoring system data to an hourly basis.
[40 CFR §63.10000(c)(1)(vi) and §63.10010(g)]

g. *PM CPMS or PM CEMS:* The permittee shall implement one of these monitoring operations to demonstrate compliance with the PM limit of Condition 4.1.1c. if both CFB boilers do not qualify as a LEE unit for PM in accordance with 40 CFR §63.10005(h).
[40 CFR §63.10000(c)(1)(iv)]

i. Install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in 40 CFR §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the CFB Boilers in tables 1 or 2 to this subpart;

[40 CFR §§63. 10010(i)]

ii. Use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in 40 CFR §§63.10010(h)(1) through (5) of this section; or
[40 CFR §§63. 10010(h)]

iii. Conduct quarterly performance testing to demonstrate compliance with the emission standard. This testing must be conducted in accordance with the applicable test methods as defined in Table 5 to Subpart UUUUU of Part 63 and calculate the results of the testing in units of the emission standard.
[40 CFR §§63.10021(d)]

h. NO_x & SO_2 CEMS: The permittee shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the permittee shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in 40 CFR §60.49Da(h) for SO_2 and Test Method 7 or 7A for NO_x.
[40 CFR §60.49Da(f)(1) and §60.48b(f)]

i. NO_x and SO_2 Emissions: The permittee shall determine 30 day rolling average for each of the CFB boilers for NO_x and SO_2, in accordance with 40 CFR §60.48Da, which is to be expressed in lb/MMBtu. The permittee shall determine the 30 day rolling average of NO_x in accordance with 40 CFR §60.48b, which is to be expressed in lb/MMBtu.
[40 CFR §60.48Da and §60.48b]

j. Records of maintaining, calibrations, checks, and output data, shall be maintained in accordance with Condition 3.4.1. The permittee must monitor and collect data according to 40 CFR 63.10020 and the site-specific monitoring plan required in Condition 4.1.1.
[40 CFR 63.10020(a) and (b)]

4.2.2. The permittee shall install, calibrates, maintain, and operate an "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A of Part 60 be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under 40 CFR 60.49Da(b)(1). The permittee shall use the output data from the "as fired" system and SO_2 CEMS to determine compliance with the percent SO_2 reduction of Condition 4.1.2.b. in accordance with 40 CFR §60.50Da(c) on daily and 30 successive boiler operating days basis. Such records of this monitoring system, data collected, and calculated values shall be maintained in accordance with Condition 3.2.1.
[40 CFR §§60.49Da(b) & (b)(3), and §§60.50Da(a) & (c)]

4.3. Testing Requirements

4.3.1. If the permittee elects to demonstrate that CFB #1 and CFB #2 qualify as low emitting EGU (LEE) for PM in accordance with 40 CFR 63.10005(h), the permittee shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status. The permittee must conduct all required performance tests described in 40 CFR §63.10007 to demonstrate that a unit qualifies for the LEE status. If the permittee satisfactorily demonstrates that both units qualify as LEE units for PM, then the PM portion of the site specific monitoring plan of Condition 4.1.1.1 and the monitoring of Condition 4.2.1.g are stayed until the unit no longer qualifies as a LEE unit for filterable PM. Should subsequent emissions testing results show a unit(s) does not meet the LEE eligibility requirements, the permittee must conduct PM emissions testing quarterly in accordance with Condition 4.2.1.g.iii.
[40 CFR §63.10000(c)(1)(iv), §63.10006(b)(1), and §63.10020(d)(3)(i)]

When conducting emissions testing to demonstrate LEE status, the permittee must increase the minimum sample volume specified in Table 2 to Subpart UUUUU of Part 63 nominally by a factor of two.

For Hg, the permittee must conduct a 30-boiler operating day performance test using Method 30B in appendix A-8 to Part 60 of Chapter 40 to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. The permittee may use a pair of sorbent traps to sample the stack gas for no more than 10 days.
[40 CFR 63.10005(h)(3)]

For affected units meeting the LEE requirements of 40 CFR §63.10005(h), the permittee must repeat the performance test once every 3 years for filterable PM and once every year for Hg according to Table 5 to Subpart UUUUU of Part 63 – Performance Testing Requirements and 40 CFR §63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, then permittee must conduct PM emissions testing quarterly in accordance with Condition 4.2.1.g.iii.
[40 CFR §§63.10006(b) & (b)(1)]

If the affected units do not qualify for Hg LEE status, then permittee must install, certify, maintain, and operate an Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to Subpart UUUUU to Part 63, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the permittee must conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1). The permittee must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.
[40 CFR §63.10006(b)(2)]

Such testing shall be conducted in accordance with Condition 3.3.1. with notifications and reports submitted in accordance with Condition 4.5.4 and 4.5.5.
[40 CFR §63.10030(d), §§63.10031(f), (f)(5) and (f)(6)]

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit, and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. For Subpart UUUUU for the CFB boilers, the permittee shall maintain records of following:

a. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §40 CFR 63.10(b)(2)(viii).
[40 CFR §63.10032(a)(2)]

b. For each PM or Hg CEMS and PM CPMS, the permittee must keep records according to the following if applicable:

i. Records described in 40 CFR §63.10(b)(2)(vi) through (xi).

ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR §63.8(d)(3).

iii. Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

[40 CFR §§63.10032(b)(1) though (b)(4)]

c. The permittee must keep the records required in Table 7 to Subpart UUUUU of Part 63 including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to the permittee.
[40 CFR §63.10032(c)]

d. For each EGU subject to an emission limit, the permittee must also keep the following records:

   i. Monthly fuel usage for each CFB boiler, including the type(s) of fuel and amount used.
   [40 CFR 63.10032(d)(1) and 45CSR§2A-7.1.a.]

   ii. For the CFB boilers that qualify as an LEE status under 40 CFR §63.10005(h), the permittee must keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant (filterable PM and/or Hg), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.
   [40 CFR 63.10032(d)(3)]

e. Regarding startup periods or shutdown periods:

   i. The permittee must keep records of the occurrence and duration of each startup or shutdown;

   [40 CFR §§63.10032(f)(1)]

   ii. The permittee must keep records of the determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and
   [40 CFR §§63.10032(f)(3)]

   iii. The permittee must keep records of the information required in 40 CFR 63.10020(e).
   [40 CFR §§63.10032(f)(4)]

f. The permittee must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment.
[40 CFR §63.10032~~1~~(g)]

g. The permittee must keep records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 CFR §63.10032~~1~~(h)]

h. The permittee must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.
[40 CFR §63.10032~~1~~(i)]

i. The permittee may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR §§63.10000(c)(1)(vi)(B) and 40 CFR §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out -of-control periods, repairs associated with monitoring system malfunctions or monitoring system out -of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system.
[40 CFR §63.100020(b)]

j. Except for periods of monitoring system malfunctions or monitoring system out -of-control periods, repairs associated with monitoring system malfunctions or monitoring system out -

b. All records shall be maintained in accordance with Condition 3.4.1.
[40 CFR 60.49b(d)(1)]

4.5. Reporting Requirements

4.5.1. For Subpart Da Reporting for SO2 and PM from the CFB boilers, the permittee shall submit reports to the Director and Administrator semiannually. The reporting periods shall begin on January 1 and July 1 with the end of the reporting periods ending on June 30 and December 31 respectively. These reports shall be postmarked by 30 days following the end of the reporting period. Such reports shall contain the following information.

a. For SO_2, the following information is reported to the Director for each 24-hour period.

i. Calendar date.

ii. The average SO_2 emission rates (lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

iii. The percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

iv. Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

v. Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

vi. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

vii. Identification of the times when the pollutant concentration exceeded full span of the CEMS.

viii. Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

ix. If the minimum quantity of emission data as required by 40 CFR §60.49Da (Condition 4.2.1.) is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of 40 CFR §60.48Da(h) is reported to the Administrator for that 30-day period:

1. The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

2. The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

3. The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.

4. The applicable potential combustion concentration.

5. The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

x. For any periods for which opacity, SO_2 or NO_X emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

xi. The responsible official of permitted facility shall submit a signed statement indicating whether:

1. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

2. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

3. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

4. Compliance with the standards has or has not been achieved during the reporting period.

xii. For the purposes of the reports required under 40 CFR §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.
[40 CFR §60.19(d) and §§60.51Da(b), (c), f), (h), and (i)]

4.5.2. The permittee shall submit a "Notification of Compliance Status" for the CFB Boilers to the Administrator before the close of business on the sixtieth (60th) day after completion of the initial compliance or LEE demonstration as required in Conditions 4.1.1.l., 4.1.1.m. and 4.1.1.n. Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the applicable information specified in 40 CFR §§63.10030(e)(1), though (e)(8). Such notification shall be submitted reference in Conditions 4.5.
[40 CFR §63.9(h)2(ii), §63.1005(k), §63.10011(e), §63.10030(e)]

4.5.3. Subpart UUUUU Reports for CFB boilers, the permittee must submit each report in Table 8 to Subpart UUUUU of Chapter 40 that applies to the CFB boilers. If continuously monitored Hg emissions are required to be used to demonstrate compliance with Condition 4.1.1.f., the permittee must also submit the electronic reports required under Appendix A to Subpart UUUUU, at the specified frequency.

The first compliance report must cover the period beginning on April 16, 2016 and ending on December 31, 2016.

The first compliance report must be postmarked or submitted electronically no later than January 31, 2017.

Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

The compliance report must contain the following information (40 CFR§§ 63.10031(c)(1) through (5)):

a. The information required by the summary report located in 40 CFR §63.10(e)(3)(vi).

b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non- waste determination by EPA or the permittee basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

c. Indicate whether the permittee burned new types of fuel during the reporting period. If the permittee did burn new types of fuel the permittee must include the date of the performance test where that fuel was in use.

d. Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to §63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 months and was delayed until the next scheduled unit shutdown.

e. For each instance of startup or shutdown:

i. Include the information required to be monitored, collected, or recorded according to the requirements of 40 CFR §63.10020(e).

f. For each excess emissions occurring at an affected source where the permittee is using a CMS to comply with that emission limit or operating limit, the permittee must include the information required in 40 CFR §63.10(e)(3)(v) in the compliance report specified in 40 CFR §63.10031(c).

4.5.4. Prior to April 16, 2017, all reports subject to electronic submissions in 40 CFR §§63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs of 40 CFR §§63.10031(f) in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:

a. The facility name, physical address, mailing address (if different from the physical address), and county;

b. The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;

c. The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;

d. If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of this chapter;

e. If any of the EGUs described in 40 CFR §63. 10031(f)(6)(iii) of this section are in an averaging plan under 40 CFR §63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;

f. The identification of each emission point to which the report applies. An "emission point" is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (e.g., "Unit 2 stack," "common stack CS001," or "multiple stack MS001");

g. The rule citation (e.g., §63.10031(f)(1), §63.10031(f)(2), etc.) for which the report is showing compliance;

h. The pollutant(s) being addressed in the report;

i. The reporting period being covered by the report (if applicable);

j. The relevant test method that was performed for a performance test (if applicable);

k. The date the performance test was conducted (if applicable); and

l. The responsible official's name, title, and phone number.

[40 CFR §§63.10031(f)(6)]

4.5.5. On or after April 16, 2017, the permittee shall submit reports of the following ~~activates~~ activities as required under Subpart UUUUU of Part 63 in accordance with the corresponding regulation:

a. Performance testing shall be submitted in accordance with 40 CFR §63.10031(f);

b. Each CEMS performance evaluation and relative accuracy test audit for the CEMS in accordance with 40 CFR §63.10031(f)(1)

c. PM CEMS or PM CPMS data in accordance with 40 CFR §63.10031(f)(2)

d. Notification of Compliance Status and Compliance Report as required in Condition 4.5.3. in accordance with 40 CFR 63.10031(f)(3).

[40 CFR §§63.10031(f), (f)(1), (f)(2), (f)(4)]

4.5.6. All reports required by Subpart UUUUU~~U~~ not subject to the requirements in 40 CFR §§63.100031, paragraphs (f) introductory text and (f)(1) through (4) (Condition 4.5.5.) must be sent to the Administrator and Director in accordance with Condition 3.5.1.. If acceptable to both the Administrator and the permittee, these reports may be submitted on electronic media. The Administrator and Director retains the right to require submittal of reports subject to 40 CFR §§63.100031, paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.

[40 CFR 63.10031(f)(5)]

4.5.7. The permittee shall submit "Annual Compliance Reports" to the Director for the Auxiliary Boilers with the first report being submitted no later than January 31, 2017, and subsequent reports are due every year thereafter. Such reports shall contain the information specified in 40 CFR §§63.7550(c)(5) (i)through (iv) and (xiv) which are:

a. Permittee and facility name, and address;

b. Process unit information, emission limitations, and operating limitations;

c. Date of report and beginning and ending dates of the reporting period;

d. The total operating time during the reporting period of each affected unit;

e. Include the date of the most recent tune-up for the boiler; and

f. Include the date of the most recent burner inspection if it was not done within the specified time schedule and was delayed until the next scheduled or unscheduled unit shutdown.

[40CFR §§63.7550(b), (b)(1), (c)(1), & (c)(5)(i) though (iv) and (xiv)

5.0. Fuel, Limestone, and Ash Handling

5.1. Limitations and Standards

5.1.1. Coal/coal refuse and limestone handling/storage facilities shall consist of the following, and particulate emissions shall be controlled as specified with maximum particulate emissions not to exceed the following:

	Type/Identity of Particulate Matter Control Equipment	Particulate Emission Limitation for Control Equipment Discharge lb/hr
Coal/Gob Receiving Hoppers (Truck)	Enclosure and Water/Chemical Dust Suppression System	
Coal/Gob Receiving Hopper (Emergency Use)	Minimize Drop Height	
Elevating Transfer Conveyor No. 1, Two Fuel Silos, Reversible Silo Feed Conveyor, Hopper Transfer Conveyor, and Transfer Points	Enclosure and Evacuation to Baghouse	0.0002
Elevating (Tripper) Conveyor No. 2 (top), Two Fuel Day Bins, and Transfer Points	Enclosure and Evacuation to Baghouse	0.0002
Mill Collecting Conveyor, Elevating Conveyor No. 2 base	Enclosure and Evacuation to Baghouse	0.0002
Two Coal/Gob Crushers (Grinding Mill, Hammer Mill), Emergency Fuel Feed Conveyor, Weigh Belt Conveyor	Enclosure and Evacuation to Baghouse	0.099
One 1,160 Ton Limestone Storage Silo	Baghouse	0.014
Limestone Truck Unloading Hopper	Enclosure and Evacuation to Baghouse	0.027
One Limestone Day Bin	Baghouse	0.005

5.1.2. Ash transfer, storage and loading facilities shall consist of the following and particulate emissions from the entire system shall be controlled as specified with maximum particulate emissions not to exceed the following:

	Type/Identity of Particulate Matter Control Equipment	Particulate Emission Limitation for Control Equipment Discharge lb/hr
Pneumatic System for Collected Flyash and Bottom Ash Handling, One 1300 Ton Ash Silo, Vacuum Blowers	Enclosure and Evacuation to Baghouse	0.028
Fully Sealed Mechanical System for Bottom Ash/Cooler Rejects, One 85 Ton Bottom Ash Silo	Baghouse	0.028
Flyash Transport (Silo Vent)	Baghouse	0.184
Wet Ash Loadout (Flyash and Bottom Ash)	Rotary dustless (wet) unloaders shall thoroughly wet ash prior to loading and handling. Ash	

	loadout(s) shall be fully enclosed and evacuated to an ash silo baghouse during all ash loading.	

5.1.3. All fugitive particulate matter control systems shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter.

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ______________________________, representing the period beginning ____________________ and ending ____________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ____ ____________________
(please use blue ink) Responsible Official or Authorized Representative Date

Name & Title ______________________________ ______________________________
(please print or type) Name Title

Telephone No. ____________________________ Fax No. ____________________________

---

1 This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

(ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.

Andrews, Edward S

From: Patrick E. Ward <PEWard@potesta.com>
Sent: Thursday, February 25, 2016 4:34 PM
To: Andrews, Edward S; 'tshirley@ppmsllc.com'
Cc: Dan Traynor (dtraynor@ppmsllc.com)
Subject: RE: 061-00027_PERM_R14-0007C-predraft.docx

Ed, Tuesday at 9:30 is fine for a meeting.

ID # 061-00027
Reg R14-0007C
Company MEA
Facility Morgantown Initials SLK

Regards,
Patrick Ward
Potesta & Associates, Inc.
7012 MacCorkle Avenue, S.E.
Charleston, West Virginia 25304
Ph: (304) 342-1400
Direct: (304) 414-4751
Fax: (304) 343-9031

From: Patrick E. Ward
Sent: Wednesday, February 24, 2016 1:47 PM
To: 'Andrews, Edward S' <Edward.S.Andrews@wv.gov>; 'tshirley@ppmsllc.com' <tshirley@ppmsllc.com>
Cc: Dan Traynor (dtraynor@ppmsllc.com) <dtraynor@ppmsllc.com>
Subject: RE: 061-00027_PERM_R14-0007C-predraft.docx

Mr. Andrews,

Attached is the track changes document for the draft permit. Also there are some technical corrections that are occurring on the MATS rule. We have attached two documents in regard to this issue which affects part of the permit (Starting on Page 31).

Todd and others are going to be in Morgantown next week and would like to come to Charleston on Tuesday to review the draft permit with you. Please let us know what time you have available next Tuesday.

Regards,
Patrick Ward
Potesta & Associates, Inc.
7012 MacCorkle Avenue, S.E.
Charleston, West Virginia 25304
Ph: (304) 342-1400
Direct: (304) 414-4751
Fax: (304) 343-9031

Entire Document
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From: Andrews, Edward S [mailto:Edward.S.Andrews@wv.gov]
Sent: Wednesday, February 17, 2016 4:04 PM

To: 'tshirley@ppmsllc.com' <tshirley@ppmsllc.com>
Cc: Patrick E. Ward <PEWard@potesta.com>; Dan Traynor (dtraynor@ppmsllc.com) <dtraynor@ppmsllc.com>
Subject: 061-00027_PERM_R14-0007C-predraft.docx

Mr. Shirley: I have attached a pre-draft of R14-0007C for your staff to review. Please use Word's Track Changes feature in noting errors/suggestions/comments. After Bev has finish her review, I will contact you to see if MEA has any input to improve the draft before public comment.

I noticed that that fugitive emissions calculation in Attachment N of your application for road dust emissions used a 50% control efficiency. However, the actual control measure was not listed. Please identify the control measure that corresponds to the 50% removal (control) efficiency used in the fugitive dust calculations.

Should you have any questions about this email or your application, please contact me.

Sincerely,

Edward S. Andrews, P.E.
Engineer
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
304.926.0499 ext. 1214

Shimshock, John

Subject: FW: EPA proposed rule - technical corrections to MATS rule

From: Eddinger, Jim [mailto:Eddinger.Jim@epa.gov]
Sent: Tuesday, December 15, 2015 9:54 AM
To: Shimshock, John
Subject: RE: EPA proposed rule - technical corrections to MATS rule

Mr. Shimshock,

The MATS technical corrections has been delayed. It is expected to be signed by mid-February 2016.

Jim

James Eddinger
Energy Strategies Group
Sector Policies and Programs Division
919-541-5426

From: Shimshock, John [mailto:John.Shimshock@nrg.com]
Sent: Monday, December 14, 2015 11:18 AM
To: Eddinger, Jim <Eddinger.Jim@epa.gov>
Subject: RE: EPA proposed rule - technical corrections to MATS rule

Greetings again Mr. Eddinger,
I'm just inquiring of any updates on this rule development that you can share. Thanks again for your help, wishing you Happy Holidays – John.

From: Eddinger, Jim [mailto:Eddinger.Jim@epa.gov]
Sent: Wednesday, September 30, 2015 12:50 PM
To: Shimshock, John
Subject: RE: EPA proposed rule - technical corrections to MATS rule

Mr. Shimshock,

The current schedule is to have the final MATS technical corrections signed by the end of November.

Jim

James Eddinger
Energy Strategies Group
Sector Policies and Programs Division
919-541-5426

From: Shimshock, John [mailto:John.Shimshock@nrg.com]
Sent: Tuesday, September 29, 2015 2:12 PM
To: Eddinger, Jim
Subject: RE: EPA proposed rule - technical corrections to MATS rule

Hi Mr. Eddinger,

I'm just inquiring of any updates that you can share. Thanks again for your help – John.

From: Shimshock, John
Sent: Friday, May 29, 2015 2:37 PM
To: 'Eddinger, Jim'
Subject: RE: EPA proposed rule - technical corrections to MATS rule

Ok, thanks for your prompt and courteous reply.

From: Eddinger, Jim [mailto:Eddinger.Jim@epa.gov]
Sent: Friday, May 29, 2015 2:22 PM
To: Shimshock, John
Subject: RE: EPA proposed rule - technical corrections to MATS rule

Mr. Shimshock,

There is not a firm schedule for finalizing the proposed technical corrections to the MATS rule but our plan is to have it finalized by the end of summer. We are in the process now of considering all the comments received, including NRG's.

Jim

James Eddinger
Energy Strategies Group
Sector Policies and Programs Division
919-541-5426

From: Shimshock, John [mailto:John.Shimshock@nrg.com]
Sent: Friday, May 29, 2015 11:12 AM
To: Eddinger, Jim
Subject: FW: EPA proposed rule - technical corrections to MATS rule

Greetings Mr. Eddinger,
I was just alerted that my inquiry to Mr. Barrett Parker earlier today may be more appropriately directed to your attention. If so, the I'd be grateful for your attention to my request. Thanks in advance for your help – John.

From: Shimshock, John
Sent: Friday, May 29, 2015 8:13 AM
To: 'parker.barrett@epa.gov'
Subject: EPA proposed rule - technical corrections to MATS rule

Greetings Mr. Parker,
I'm inquiring if you are aware of, and can share, EPA's projected schedule for completing the recent technical corrections to the MATS rule (FR notice for the proposed rule attached). NRG would be grateful for EPA's consideration of our comments to the proposed rule. Thanks in advance for your attention to my request, I'm looking forward to your response – John.

John P. Shimshock
Senior Air Environmental Scientist
NRG Energy Inc.
Southpointe Operations Center
121 Champion Way
Canonsburg, PA 15317
Telephone: (724) 597-8405
Cellular: (724) 344-3784
John.shimshock@nrg.com

West Virginia Department of Environmental Protection

Earl Ray Tomblin
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Permit to Modify

R14-0007C

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 C.S.R. 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:

Morgantown Energy Associates
Morgantown Energy Facility
061-00027

William F. Durham
Director

Issued: DRAFT

This permit will supercede and replace Permit R13-1058B/R14-0007B.

Facility Location:	555 Beechurst Avenue Morgantown, Monongalia County, West Virginia 26505
Mailing Address:	Same as above
Facility Description:	Fossil Fuel Fired Cogeneration Facility
NAICS Codes:	221112
UTM Coordinates:	589.20 km Easting • 4,388.10 km Northing • Zone 17
Permit Type:	Modification
Description of Change:	This action is for the change in method of operation ~~required~~ for the two fluidized bed boilers to ~~license~~permit the installation and subsequent operation, as[redacted]ed, ~~comply with the MATs~~MATS, ~~which includes the installation~~ of ~~NN~~SNCR systems on both CFB boilers. This action also addresses the requirements pursuant to 40 CFR 63 Subpart UUUUU (Mercury and Air Toxics Rule, MATS).

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Table of Contents

Run TOC

1.0. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S001A	Vents 1 & 2	Elevating Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001B	Vents 1 & 2	TP001B – Elevating Conveyor1 to Reversible Feed Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001C	Vents 1 & 2	Reversible Feed Conveyor 1	1989	500 TPH	ES 1/BH 1& 2
S001D	Vent 1	TP001D - Reversible Feed Conveyor 1 to Coal Silo 1	1989	500 TPH	ES 1/BH 1~~& 2~~
S001E	Vent1	Coal Silo 1	1989	2,100 Tons	ES 1 / BH 1
S001F	Vents 1 & 2	TP001F - Elevating Conveyor 1 to Emergency Bypass Conveyor	2001	120 TPH	ES 1 / BH 1 & 2
S002A	Vent 2	TP002A - Reversible Feed Conveyor 1 to Gob Storage Silo 1	1989	500 TPH	ES 1 / BH 2
S002B	Vent 2	Gob Storage Silo 1	2001	2,100 Tons	ES 1 / BH 2
S003A	Vent 3	TP003A – Coal Silo 1 to Weigh Belt Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003B	Vent 3	TP003B – Gob Storage Silo 1 to Weigh Belt Conveyor 2	1989	60 TPH	ES 2 / BH 3
S003C	Vent 3	Weigh Belt Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003D	Vent 3	Weigh Belt Conveyor 2	2001	60 TPH	ES 2 / BH 3
S003E	Vent 3	TP003E - Weigh Belt Conveyor 1& 2 to Grinding Mill	1989	60 TPH	ES 2 / BH 3
S003F	Vent 3	TP003F - Weigh Belt Conveyor 1& 2 to Hammer Mill	1989	60 TPH	ES 2 / BH 3
S003G	Vent 3	TP003G – Emergency Mill Feed System Hopper 1 to En-mass Elevating Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003H	Vent 3	En-mass Elevating Conveyor 1	1989	60 TPH	ES 2 / BH 3
S003I	Vent 3	TP003I – En-mass Elevating Conveyor 1 to Mill Inlet Chute System	1989	60 TPH	ES 2 / BH 3
S003J	Vent 3	Grinding Mill 1	1989	60 & 90 TPH	ES 2 / BH 3
S003K	Vent 3	Hammer Mill 1	1989	60 TPH	ES 2 / BH 3

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S004A	Vent 4	TP004A – Grinding Mill 1 to Mill Collecting Conveyor 1	1989	60 & 90 TPH	ES 3 / BH 4
S004B	Vent 4	TP004B – Hammer Mill 1 to Mill Collecting Conveyor 1	1989	60 TPH	ES 3 / BH 4
S004C	Vent 4	TP004C – Baghouse 4 Dust Discharge to Mill Collecting Conveyor 1	1989	5 TPH (est.)	ES 3 / BH 4
S004D	Vent 4	Mill Collecting Conveyor 1	2001	120 TPH	ES 3 / BH 4
S004E	Vent 4	TP004E – Mill Collecting Conveyor 1 to Elevating Conveyor 2	1989	120 TPH	ES 3 / BH 4
S004F	Vent 4	TP004F – Baghouse 3 Dust Discharge to Mill Collecting Conveyor 1	1989	12 TPH	ES 3 / BH 4
S004G	Vent 4	Elevating Conveyor 2 (Bottom Half)	2001	120 TPH	ES 3 / BH 4
S005A	Vent 5	Elevating Conveyor 2 (Top Half)	1989	120 TPH	ES 4 / BH 5
S005B	Vent 5	TP005B – Elevating Conveyor 2 to Fuel Bin 1	1989	120 TPH	ES 4 / BH 5
S005C	Vent 5	TP005C – Elevating Conveyor 2 to Fuel Bin 2	1989	120 TPH	ES 4 / BH 5
S005D	Vent 5	Fuel Bin 1	1989	375 Tons	ES 4 / BH 5
S005E	Vent 5	Fuel Bin 2	1989	375 Tons	ES 4 / BH 5
S005F	Vent 5	Emergency Bypass Conveyor	2001	120 TPH	ES 4 / BH 5
Limestone Handling					
S006A	Vent 6	TP006A – Transfer from Truck to Limestone Unloading Hopper 1	1989	37.5 TPH	BE 2 / BH 6
S006B	Vent 6	TP006B – Transfer from Truck to Limestone Unloading Hopper 2	1989	37.5 TPH	BE 2 / BH 6
S006C	Vent 6	Limestone Unloading Hopper 1	1989	75 TPH	BE 2 / BH 6
S006D	Vent 6	Limestone Unloading Hopper 2	1989	75 TPH	BE 2 / BH 6
S007A	Vent 7 & 8	TP007A – Transfer from Limestone Unloading Hopper 1 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S007B	Vent 7 & 8	TP007B – Transfer from Limestone Unloading Hopper 2 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S007C	Vent 7 & 8	TP007C – Transfer from Truck to Pneumatic Conveying System 1	1989	75 TPH	PCS 1

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S007D	Vent 7	TP007D – Transfer from Pneumatic Conveying System 1 to Limestone Silo 1	1989	75 TPH	ES 5 / BVF 1
S007E	Vent 7	Limestone Silo 1	1989	1,160 Tons	ES 5 / BVF 1
S008A	Vent 8	TP008A – Transfer from Limestone Silo 1 to Pneumatic Conveying System 1	1989	75 TPH	PCS 1
S008B	Vent 8	TP008B – Transfer from Pneumatic Conveying System 1 to Limestone Bin 1	1989	75 TPH	ES 6 / BVF 2
S008C	Vent 8	Limestone Bin 1	1989	250 Tons	ES 6 / BVF 2
S008D	Vent 8	TP008D– Limestone Bin 1 to Gravimetric Feeder/Conveyor A	1989	10 TPH	ES 6 / BVF 2
S008E	Vent 8	Gravimetric Feeder/Conveyor A	1989	10 TPH	ES 6 / BVF 2
S008F	Vent 8	TP008F– Gravimetric Feeder/Conveyor A to Rotary Valve A	1989	10 TPH	ES 6 / BVF 2
S008G	Vent 8	TP008G– Limestone Bin 1 to Gravimetric Feeder/Conveyor B	1989	10 TPH	ES 6 / BVF 2
S008H	Vent 8	Gravimetric Feeder/Conveyor B	1989	10 TPH	ES 6 / BVF 2
S008I	Vent 8	TP008I– Gravimetric Feeder/Conveyor B to Rotary Valve B	1989	10 TPH	ES 6 / BVF 2
Boiler & Associated Equipment					
S009A	STACK1	TP009A - Limestone Feeder Rotary Valve A to Pneumatic Conveying System 2	1989	10 TPH	PCS / BH 7 & 8
S009B	STACK1	TP009B - Limestone Feeder Rotary Valve B to Pneumatic Conveying System 2	1989	10 TPH	PCS / BH 7 & 8
S009C	STACK1	TP009C - Pneumatic Conveying System 2 to CFB Boiler 1	1989	10 TPH	PCS / BH 7 & 8
S009D	STACK1	TP009D - Pneumatic Conveying System 2 to CFB Boiler 2	1989	10 TPH	PCS / BH 7 & 8
S009E	STACK1	TP009E – Fuel Bin 1 to Enclosed Conveying System 7	1989	46 TPH	ES / BH 7 & 8
S009F	STACK1	TP009F – Fuel Bin 2 to Enclosed Conveying System 7	1989	46 TPH	ES / BH 7 & 8
S009G	STACK1	Enclosed Conveying System 7 to CFB Boiler 1	1989	46 TPH	ES / BH 7 & 8

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S009H	STACK1	Enclosed Conveying System 7 to CFB Boiler 2	1989	46 TPH	ES / BH 7 & 8
S009J	STACK1	Ahlstrom Pyroflow CFB Boiler/Cyclone #1	1989, 2016- ~~(projected)~~ ~~for~~ SNCR	375 MM~~mm~~Btu/hr	Limestone Injection, BH 8 & SNCR
S009K	STACK1	Ahlstrom Pyroflow CFB Boiler/Cyclone #2	1989, 2016 - ~~(projected)~~ ~~for~~ SNCR	375 MM~~mm~~Btu/hr	Limestone Injection, BH 7 & SNCR
S009L	STACK1	Zurn Auxiliary Boiler #1	1989	132 MM~~mm~~Btu/hr	LNB
S009M	STACK1	Zurn Auxiliary Boiler #2	1989	132 MM~~mm~~Btu/hr	LNB
		Ash Handling			
S010A	Vent 9	TP010A – CFB Boiler 1 Bottom Ash Screw A to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010B	Vent 9	TP010C – CFB Boiler 1 Bottom Ash Screw B to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010C	Vent 9	TP010E – CFB Boiler 1 Bottom Ash Screw C to Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010D	Vent 9	Drag Chain Conveyor 101	1989	16.5 TPH	ES 8 / BVF 3
S010E	Vent 9	TP010I – CFB Boiler 2 Bottom Ash Screw A to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010F	Vent 9	TP010K – CFB Boiler 2 Bottom Ash Screw B to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010G	Vent 9	TP010M – CFB Boiler 2 Bottom Ash Screw C to Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010H	Vent 9	Drag Chain Conveyor 201	1989	16.5 TPH	ES 8 / BVF 3
S010I	Vent 9	TP010Q – Drag Chain Conveyor 101 to Clinker Grinder 1	1989	16.5 TPH	ES 8 / BVF 3
S010J	Vent 9	TP010S – Drag Chain Conveyor 201 to Clinker Grinder 3	1989	16.5 TPH	ES 8 / BVF 3
S010K	Vent 9	Clinker Grinder 1	1989	16.5 TPH	ES 8 / BVF 3

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S010L	Vent 9	Clinker Grinder 3	1989	16.5 TPH	ES 8 / BVF 3
S010M	Vent 9	TP010Y – Clinker Grinder 1 to Bottom Ash Holding Bin 1	1989	16.5 TPH	ES 8 / BVF 3
S010N	Vent 9	TP010AA – Clinker Grinder 3 to Bottom Ash Holding Bin 1	1989	16.5 TPH	ES 8 / BVF 3
S010O	Vent 9	Bottom Ash Holding Bin	1989	76.5 Tons	ES 8 / BVF 3
S011A	Vent 10	TP011A – Bottom Ash Holding Bin Discharge A to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011B	Vent 10	TP011B – Bottom Ash Holding Bin Discharge B to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011C	Vent 10	TP011C – Bottom Ash Holding Bin Discharge C to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011D	Vent 10	TP011D – CFB No. 1 Air Heater Hopper to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011E	Vent 10	TP011E – CFB No. 2 Air Heater Hopper to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011F	Vent 10	TP011F – CFB No. 1 Baghouse Row 1 Discharge to Vacuum Conveying System A	1989	50 TPH	ES 3 / VCS A / FS A
S011G	Vent 10	TP011G – CFB No. 1 Baghouse Row 2 Discharge to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011H	Vent 10	TP011H – CFB No. 2 Baghouse Row 1 Discharge to Vacuum Conveying System B	1989	50 TPH	ES 3 / VCS B / FS B
S011I	Vent 10	TP011I – CFB No. 2 Baghouse Row 2 Discharge to Vacuum Conveying System C	1989	50 TPH	ES 3 / VCS C / FS C
S011J	Vent 10	Filter/Separator A Exhaust	1989	50 TPH	ES 3 / VCS A / FS A
S011K	Vent 10	Filter/Separator B Exhaust	1989	50 TPH	ES 3 / VCS B / FS B
S011L	Vent 10	Filter/Separator C Exhaust	1989	50 TPH	ES 3 / VCS C / FS C
S012A	Vent 11	TP012A – Filter/Separator A to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012B	Vent 11	TP012B – Filter/Separator B to Ash Silo1	1989	50 TPH	ES 9 / BH 9
S012C	Vent 11	TP012C – Filter/Separator A to Ash Silo1	1989	50 TPH	ES 9 / BH 9

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S012D	Vent 11	Ash Silo1	1989	1,300 Tons	ES 9 / BH 9
S012E	Vent 11	TP012E – Ash Silo to Truck	1989	300 TPH	BH 9 / BE 4 / AC 1
S012F	Vent 11	TP012FE – Ash Silo to Truck	1989	300 TPH	BH 9 / BE 4 / AC 2
Fuel Receiving & Emergency Fuel Feed Fugitives					
S00F1	Fugitive Emission 1	TP00F1 – Transfer from Truck to Fuel Unloading Hopper/Vibratory Feeder 1	1989	250 TPH	BE 1 / WS 1
S00F2	Fugitive Emission 2	Fuel Unloading Hopper 1	1989	250 TPH	BE 1 / WS 1
S00F3	Fugitive Emission 3	Vibratory Feeder 1	1989	250 TPH	BE 1 / ES 1
S00F4	Fugitive Emission 4	TP00F4 – Transfer from Truck to Fuel Unloading Hopper/Vibratory Feeder 2	1989	250 TPH	BE 1 / WS 2
S00F5	Fugitive Emission 5	Fuel Unloading Hopper 2	1989	250 TPH	BE 1 / WS 2
S00F6	Fugitive Emission 6	Vibratory Feeder 2	1989	250 TPH	BE 1 / ES 1
S00F7	Fugitive Emission 7	TP00F7 – Vibratory Feeder 2 to Transfer Conveyor 1	1989	250 TPH	BE 1 / ES 1 / WS 3
S00F8	Fugitive Emission 8	TP00F8 – Vibratory Feeder 1 to Transfer Conveyor 1	1989	250 TPH	BE 1 / ES 1 / WS 4
S00F9	Fugitive Emission 9	Transfer Conveyor 1	1989	500 TPH	BE 1 / ES 1
S00F10	Fugitive Emission 10	TP00F10 – Transfer Conveyor 1 to Elevating Conveyor 1	1989	500 TPH	BE 1 / ES 1 / WS 5
S00F11	Fugitive Emission 11	TP00F11 – Dribble Chute 1 to Dribble Chute Catch Bin 1	1989	N/A	BE 1
S00F12	Fugitive Emission 12	Dribble Chute Catch Bin 1	1989	N/A	BE 1
S00F13	Fugitive Emission 13	TP00F13 – Dribble Chute Catch Bin 1 to Dribble Chute Conveyor 1	1989	N/A	BE 1
S00F14	Fugitive Emission 14	TP00F14 – Dribble Chute Conveyor 1 to Transfer Conveyor 1	1989	N/A	BE 1

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
S00F15	Fugitive Emission 15	TP00F15 – Front End Loader to Emergency Mill Feed System Hopper 1	1989	60 TPH	N/A
S00F16	Fugitive Emission 16	Emergency Mill Feed System Hopper 1	1989	60 TPH	N/A

[1] AC – Ash Conditioner; BH – Baghouse; BE – Building Enclosure; BVF – Bin Vent Filter; ES – Enclosed System; FS – Filter Separator; LNB – Low NO_x Burners; , SNCR – Selective Non-catalytic Reduction System, PCS – Pneumatic Conveying System; VCS – Vacuum Conveying System; WS – Water Spray.

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments	**NOx**	Nitrogen Oxides
CBI	Confidential Business Information	**NSPS**	New Source Performance Standards
CEM	Continuous Emission Monitor	**PM**	Particulate Matter
CES	Certified Emission Statement	**$PM_{2.5}$**	Particulate Matter less than 2.5 µm in diameter
C.F.R. *or* **CFR**	Code of Federal Regulations		
CO	Carbon Monoxide	**PM_{10}**	Particulate Matter less than 10µm in diameter
C.S.R. *or* **CSR**	Codes of State Rules		
DAQ	Division of Air Quality	**Ppb**	Pounds per Batch
DEP	Department of Environmental Protection	**Pph**	Pounds per Hour
		Ppm	Parts per Million
dscm	Dry Standard Cubic Meter	**Ppmv or ppmv**	Parts per Million by Volume
FOIA	Freedom of Information Act		
HAP	Hazardous Air Pollutant	**PSD**	Prevention of Significant Deterioration
HON	Hazardous Organic NESHAP		
HP	Horsepower	**Psi**	Pounds per Square Inch
lbs/hr	Pounds per Hour	**SIC**	Standard Industrial Classification
LDAR	Leak Detection and Repair		
M	Thousand	**SIP**	State Implementation Plan
MACT	Maximum Achievable Control Technology	**SNCR**	Selective Non-catalytic Reduction
MDHI	Maximum Design Heat Input	**SO_2**	Sulfur Dioxide
MM	Million	**TAP**	Toxic Air Pollutant
MMBtu/hr *or* **mmbtu/hr**	Million British Thermal Units per Hour	**TPY**	Tons per Year
		TRS	Total Reduced Sulfur
MMCF/hr *or* **mmcf/hr**	Million Cubic Feet per Hour	**TSP**	Total Suspended Particulate
		USEPA	United States Environmental Protection Agency
NA	Not Applicable		
NAAQS	National Ambient Air Quality Standards	**UTM**	Universal Transverse Mercator
		VEE	Visual Emissions Evaluation
NESHAPS	National Emissions Standards for Hazardous Air Pollutants	**VOC**	Volatile Organic Compounds
		VOL	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*;

2.3.2. 45CSR14 – *Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration;*

2.4. Term and Renewal

2.4.1. This permit supersedes and replaces previously issued Permit R13-1058B/R14-0007B. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule;

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-1058/R14-00-7, R13-1058B/R14-0007B, R14-0007C (the application for R140007C was filed by the applicant as a Modification to the underlying Construction Permits and Title V operating permit), and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.11 and 10.3.]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies; i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by

improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5 The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1.]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the new processes ~~operations~~ authorized under this permit update.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] ***[State Enforceable Only]***

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.1.7. All plant roads and haulways shall be paved and shall be kept clean by appropriate measures to minimize the emissions or entrainment of fugitive particulate matter.
[45 CSR §2-5.1.]

3.1.8. There shall be no open stockpiling of coal or coal refuse at the permitting facility.
[45 CSR §2-5.1.a.]

3.1.9. All ~~track~~trucks delivering coal or coal refuse and trucks removing ash from the facility shall be fully covered or enclosed.
[45 CSR §§2-5.1. & 5.1.b.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

1. The permit or rule evaluated, with the citation number and language;
2. The result of the test for each permit or rule condition; and,
3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State Enforceable Only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class with postage prepaid to the address(es) set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

If to the DAQ:
Director
WVDEP
Division of Air Quality
601 57th Street
Charleston, WV 25304-2345

If to the US EPA:
Associate Director
Office of Air Enforcement and Compliance Assistance
(3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

3.5.4. **Operating Fee**

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements for the Boilers (CFB and Auxiliary Boilers)

4.1. Limitations and Standards

4.1.1. The following conditions and requirements are specific to the circulating fluidized bed boilers (ID S009J and S009K):

Commented [DT1]: Please inset section 4.1.7 including the Table from the Title V permit to maintain consistency in the permit limitations.

a. Particulate Matter (PM) emissions emitted to the atmosphere from ~~each unit~~ the common stack serving the boilers shall not exceed the following limits to the corresponding averaging periods.

i. PM emission rate shall not exceed 0.03 pounds per MMBtu of heat input on a 30-day rolling average.
[45 CSR §2-4.1.b., 40 CFR §60.42Da(a), ~~and 40 CFR §63.10005(a) Row 2b of Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs.~~]

ii. PM concentration of no greater than 0.016 grains per dscf corrected to 3.5 percent oxygen.

Add

iii. Filterable PM emission rate shall not exceed either ~~3.0 E-2~~0.03 lb/MMBtu or ~~3.0 E-1~~0.30 lb/MWh (gross basis) on a 30 boiler operating day rolling average. **[40 CFR §63.10005(a) Row 1a of Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs. Pursuant to the application for this permit, the permittee has elected to comply with the non-mercury emission limits under Subpart UUUUU via compliance with the filterable PM emission limit.]**

b. Sulfur Dioxide (SO_2) emissions emitted to the atmosphere from ~~each unit~~ the common stack serving the boilers shall not exceed the following ~~limits~~ to the corresponding averaging periods.

i. SO_2 emission rate shall not exceed ~~no greater than~~ 0.4~~2~~0 lb of SO_2 per MMBtu on a 30-~~boiler operating~~ day rolling average.
[40 CFR §60.43Da(a)(2), ~~40 CFR §§63.9991(c), 63.10005a(2)(i), Row 2b of Table 2 to Subpart UUUUU of Part 63 — Emission Limits for Existing EGUs~~, 45 CSR §10.]

ii. The SO_2 reduction efficiency from each of the two (2) circulating fluidized bed boilers~~unit~~ shall be not less than 94.6% on a 30-day rolling average basis. ~~daily basis and 70% on a 30-day rolling basis.~~ *[Compliance with this streamlined limit ensures compliance with the 50 percent reduction requirement in 40 C.F.R. §60.43Da(a)(2).]*
~~**[40 CFR §60.43Da(a)(2)]**~~

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iii. Effective Apr1 16, 2016, SO_2 emission rate shall not exceed ~~either~~ 0.20 ~~2.0 E-1~~ lb/MMBtu or 1.5~~-E0~~ lb/MWh (gross basis) on a 30 boiler operating day rolling average. **[40 CFR §§63.9991(c), 63.10005a(2)(i), Row 1b of Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs. Pursuant to the application for this permit, the permittee has elected to comply with the hydrogen chloride emission limit under Subpart UUUUU via compliance with the SO_2 emission limit.]**

~~iii.~~iv. The permittee shall operate a dry flue gas desulfurization system for the unit at all times consistent with 40 CFR §63.10000(b). The permittee complies with this requirement through limestone injection into the CFB boilers.
[40 CFR §63.9991(c)(2)]

c. Emissions of nitrogen oxides (NO_x) emitted to the atmosphere from ~~each unit~~ the common stack serving the boilers shall not exceed the following limits to the corresponding averaging periods.

   i. NOx, ~~NO_2~~ concentration shall not exceed ~~no greater than~~ 293 ppmvd corrected to 3 % oxygen on a 24-hr average basis.

   ii. NOx, ~~NO_2~~ emission rate shall not exceed ~~no greater than~~ 0.40 lb of NO_2 per MMBtu on a 30 day rolling average basis. ~~Compliance with this limit shall be demonstrated using CEMCEMS as required in Condition 4.2.1.~~

   iii. The permittee shall operate the SNCR in such manner to maintain compliance with the above ~~the~~ NOx limits and in Condition 4.1.3.c.

d. Emissions of carbon monoxide (CO) ~~from~~ emitted to the atmosphere from ~~each unit~~ the common stack serving the boilers shall not exceed the following limits to the corresponding averaging periods.

   i. CO concentration shall not exceed ~~no greater than~~ 188 ppmvd corrected to 3 % oxygen on a 24-hr average basis.

   ii. CO emissions rate shall not exceed 0.157 lb per MMBtu..

e. Emissions of volatile organic compounds (VOC) emitted to the atmoshphere from ~~each unit~~ the common stack serving the boilers shall not exceed the following limits to the corresponding averaging periods.

   i. VOC emissions rate shall not exceed 0.0074 lb per MMBtu.

f. Emissions of mercury (Hg) emitted to the atmosphere from ~~each unit~~ the common stack serving the boilers shall not exceed 1.2~~E0 2~~ lb/TBtu ~~per Trillion BTU~~ or 0.01~~3 E-2~~ lb/GWh (gross basis) based on a thirty 30 boiler operating day rolling average.
[40CFR§§63.9991(a)(1); Row 1c of Table 2 to Subpart UUUUU of Part 63; §63.10000(a); and §63.10010(g)]

g. At all times, the permittee must operate and maintain each unit, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
[40 CFR §63.10000(b)]

h. The permittee shall conduct a tune-up of the burner and combustion controls of each unit at least once every 36 calendar months in accordance with the following:

   i. The permittee must perform an inspection of the burner at least once every 36 calendar months. The permittee may delay the first burner inspection until the next scheduled unit outage provided the permittee meet the requirements of 40 CFR §63.10005.

   ii. As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

1. Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection,

2. Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator.

iii. As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

iv. As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

v. As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

vi. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

vii. Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add- on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

viii. While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_x and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than ~~continua~~ continuous values before and after each optimization adjustment made by the system.

i. During startup and shut down operations, the permittee must operate all continuous monitoring systems.
[40 CFR 63.10000(a), Rows 3 & 4 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

j. For startup of each unit, the permittee shall use natural gas to the maximum extent possible throughout the startup period. The permittee shall operate the associated PM control device for the unit within one hour of adding coal to the unit.

[40 CFR 63.10000(a), Row 3 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

k. During shutdown of each unit, the permittee shall operate all applicable control devices and continue to operate those control devices after the cessation of coal fuel being feed into the units and for as long as possible thereafter considering operational and safety concerns.
[40 CFR 63.10000(a), Row 4 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards]

l. If the permittee elects to demonstrate~~s~~ compliance with PM and/or Hg emissions limit of items a.iii~~.~~ and f of this condition, respectively, through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan in accordance with Conditions 3.5.1. at least 60 days before the initial performance evaluation (where applicable) of the CMS. The site-specific monitoring plan shall include the information specified in 40 CFR 63.10000(d)(5)(i) through (d)(5(vii). The permittee must operate and maintain the CMS according to the site-specific monitoring plan.
[40 CFR §§63.10000(d)(1), (d)(2) and (d)(4)]

m. Before October 13, 2016, the permittee shall ~~either~~ demonstrate initial and continuous compliance of the filterable particulate matter (PM) standard. The initial compliance demonstration may be performed by ~~or~~ initiating an emissions test program designed to ~~or~~ demonstrate that the CFB boilers qualify as a low emitting EGU (LEE) for filterable PM accordance with 40 CFR 63.10005(h).
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(iv)]

n. Before October 13, 2016, the permittee shall demonstrate initial and continuous compliance of the hydrogen chloride (HCl) standard or the alternative to the HCl standard, which is the SO_2 standard, using SO_2 CEMS in accordance with Condition 4.2.1.
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(v)]

o. Before October 13, 2016, the permittee shall either demonstrate initial compliance of the mercury standard of 40 CFR §63.10005(a) or demonstrate that the CFB boilers qualify as a low emitting EGU (LEE) for mercury in accordance with 40 CFR 63.10005(h).
[40 CFR §63.9984(f), 63.10000(c)(1), (c)(1)(i) & (c)(1)(vi)]

4.1.2. The following conditions and requirements are specific to the auxiliary boilers (ID S009L and S009M):

Commented [DT2]: Please inset section 4.1.5 including the Table from the Title V permit to maintain consistency in the permit limitations.

a. During those periods when neither of the two fluidized bed boilers are in operation but steam demand for West Virginia University requires operation of either or both of the gas-fired auxiliary boilers, air pollutant e~~E~~missions from ~~each unit~~ the common stack serving the boilers shall not exceed the emission limits in Table 4.1.2.a.

Table 4.1.2.a. Emission Limits for the Auxiliary Boilers		
Pollutant	lb/hr	lb/MMBtu
Particulate Matter (PM)	1.20	0.0045~~N/A~~
Sulfur Dioxide (SO_2)	0.14	5.3 X10^{-4}
Nitrogen Oxides (NOx~~NO2~~)	50	~~0.190~~.189*
Volatile Organic Compounds (VOC)	1.95	~~0.010~~.0074
Carbon Monoxide (CO)	10	~~0.040~~.038

Commented [DT3]: This table is different than the limits identified in the Title V permit

Commented [DT4]: Rounding

Commented [DT5]: Rounding?

Commented [DT6]: Rounding?

* Emission limit shall be demonstrated on a 30 day rolling average basis. **[40 CFR §60.44b(i)]**

b. The permittee shall conduct annual tune-ups of each boiler once every year in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. Subsequent tune-ups shall be conducted no later than 13 months from previous tune-up. If the unit is not operating on the required date for a tune-up, then the tune-up must be conducted within 30 calendar days of re-startup. These tune-ups shall consist of the following:

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment, but each burner must be inspect at least once every 12 months;

ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown);

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, which includes ~~the~~ verifying or ensur~~e~~ing the manufacturer's NO_x concentration ~~specifications~~specifications are ~~maintain~~maintained;

v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).
[40 CFR §§63.7500(a)(1) & (c); §63.7505(a); §63.7510(e); §63.7515(d); §§63.7540(a)(10), (11) & (12); and Table 3 to Subpart DDDDD of Part 63—Work Practice Standards]

4.1.3. ~~The~~ During periods when the steam demand for West Virginia University requires the combined operation of the circulating fluidized bed boilers and the auxiliary boilers, air pollutant emissions from Emission Point 43 (Stack 1) shall not exceed the following emission limitations:

Commented [DT7]: Please inset section 4.1.9 including the Table from the Title V permit to maintain consistency in the permit limitations.

a. Particulate matter emission shall not exceed 22.5 pounds per hour.

b. Sulfur dioxide emission shall not exceed ~~150~~ 285 pounds per hour on a 24 hour -average basis. ~~.~~

c. Nitrogen oxides (NO_x ~~NO_2~~) emission shall not exceed 300 pounds per hour on a 24 hour average basis. ~~(24-hours average).~~

d. Carbon monoxide emissions shall not exceed 127.5 pounds per hour.

e. Volatile organic compounds emissions shall not exceed 7.5 pounds per hour.

f. Lead emissions shall not exceed 0.13 pound per hour.

g. Fluorides emissions shall not exceed 0.4 pounds per hour.

h. Beryllium emissions shall not exceed 0.0002 pounds per hour.

i. Arsenic emissions shall not exceed 0.002 pounds per hour.

j. Radionuclides emissions shall not exceed 0.0009 pounds per hour.

k. Visible emissions shall not exceed 10% opacity based on a six minute average.
[45 CSR §2-3.1. and 40 CFR §60.42Da(b)]

4.1.4. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.11.]

4.2. Monitoring Requirements

4.2.1. *Continuous Monitoring Requirements:* The permittee shall install, calibrate, maintain and operate CEMS, continuous opacity monitor (COMS) and a diluent monitor to measure and record the emissions of SO_2, NO_x, and other parameters to determine compliance from the CFB boilers and the auxiliary boilers venting through Stack 1 in a manner sufficient to demonstrate continuous compliance with the ~~CEMS-based~~ SO_2 and NOx emission standards in Condition 4.1.1. and Condition 4.1.2. Such records of this monitoring system, data collected, and calculated values shall be maintained in accordance with Condition 3.2.1. These systems shall be installed, calibrated, properly functioning, and certified in accordance with the following requirements:

a. *SO_2 CEMS:* The SO_2 CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75 provide that the requirements of 40 CFR §60.49a(b(4)(i – iii) are met. Record keeping and reporting shall be conducted pursuant Subpart F and G in 40 CFR 75. **[40 CFR §60.49a(b)(4) and 45 CSR §10-8.2.c.1.]**

i. For each hour in which valid data are obtained for all parameters, the permittee must calculate the SO2 emission rate and the calculated pollutant emission rate to each unit that shares the common stack, which is Stack 1 for CFB #1, CFB #2, and both auxiliary boilers.
[40 CFR §63.10010(a)(3)(B)]

ii. For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in Sections 2.1 through 2.3 of Appendix B to Part 75 of Chapter 40, with the following addition: The permittee must perform the linearity checks required in Section 2.2 of Appendix B to Part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.
[40 CFR §60.49Da(b)(3) and 40 CFR §63.10010(f)(2)]

iii. Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.
[40 CFR §63.10010(f)(3)]

iv. Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the Part 75 SO_2 data and do not use Part 75 substitute data values. For startup or shutdown hours (as defined in 40 CFR §63.10042) the default electrical load and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in 40 CFR §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO_2 emission rate for any of these hours.
[40 CFR §60.49Da(b)(4)(iii) and 40 CFR §63.10010(f)(4)]

b. *NO_x CEMS:* The NO_x CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75.

For use of NO_x CEMS used to demonstrate compliance for the auxiliary boilers (S009L and S009M), the permittee shall also meet the requirements of 40 CFR §60.49b. Data reported to meet the requirements of 40 CFR §60.49b for the auxiliary boilers shall not include data substituted using the missing data procedures in Subpart D of Part 75 of Chapter 40, nor shall the data have been bias adjusted according to the procedures of Part 75 of Chapter 40.
[40 CFR §60.48b(b)(2)]

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where SO_2 and NO_x are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
[40 CFR §60.49Da(b)(4)(i) and 40 CFR §60.48b(b)(1)]

i. If the permittee use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of emissions limit in Conditions 4.1.1.b.i., the O2 or CO2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The permittee must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O2 or CO2 data in the emissions calculations; do not use part 75 substitute data values.
[40 CFR §§6310010(b)]

d. *Flow Monitor:* The volumetric flow rate of the flue gas shall be monitored at the location where SO_2 and NO_x are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
[40 CFR §60.49Da(m)]

e. *COMS:* ~~Visual emissions~~ Exhaust gas opacity from Stack 1 shall be monitored using a continuous opacity monitoring system for the purpose of demonstrating compliance with Condition 4.1.3.k. The permittee shall install calibrate, maintain, and ~~operation~~ operate the COMS in accordance with Performance Specification (PS) 1 in 40 CFR Part 60, Appendix B.
[40 CFR §§60.49Da(a) and (a)(1), 45 CSR §2-8.2.a.1., and 45 CSR §2A-6.2.]

f. *Hg CEMS or sorbent trap monitoring system:* The permittee must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with Appendix A to Subpart UUUUU of Part 63, Chapter 40 if both CFB boilers do~~es~~ not qualify as a LEE unit for Hg in accordance with 40 CFR 63.10005~~010000~~(h). The permittee must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A to Subpart UUUUU of Part 63, Chapter 40, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days.

Section 7.1.4.3 of Appendix A to Subpart UUUUU of Part 63, Chapter 40 explains how to reduce sorbent trap monitoring system data to an hourly basis.
[40 CFR §63.10000(c)(1)(vi) and §63.10010(g)]

g. *PM CPMS or PM CEMS:* The permittee shall implement one of these monitoring operations to demonstrate~~d~~ compliance with the PM limit of Condition 4.1.1.a.iii~~i.~~ if both CFB boilers do~~es~~ not qualify as a LEE unit for PM in accordance with 40 CFR §63.10005(h).
[40 CFR §63.10000(c)(1)(iv)]

i. Install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in 40 CFR §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the CFB Boilers in tables 1 or 2 to this subpart;
[40 CFR §§63. 10010(i)]

ii. Use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in 40 CFR §§63.10010(h)(1) through (5) of this section; or
[40 CFR §§63. 10010(h)]

iii. Conduct quarterly performance testing to demonstrate compliance with the emission standard. This testing must be conducted in ~~conducted in~~ accordance with the applicable test methods as defined in Table 5 to Subpart UUUUU of Part 63 and calculate the results of the testing in units of the emission standard.
[40 CFR §§63.10021(d)]

h. NO_x & SO_2 CEMS: The permittee shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the permittee shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in 40 CFR §60.49Da(h) for SO_2 and Test Method 7 or 7A for NO_x.
[40 CFR §60.49Da(f)(1) and §60.48b(f)]

i. NO_x and SO_2 Emissions: The permittee shall determine 30 day rolling average for each of the CFB boilers for NO_x and SO_2 , in accordance with 40 CFR §60.48Da, , which is to be expressed in lb/MMBtu. The permittee shall determine the 30 day rolling average of NO_x in accordance with 40 CFR §60.48b, which is to be expressed in lb/MMBtu.
[40 CFR §60.48Da and §60.48b]

j. Records of maintaining, calibrations, checks, and output data, shall be maintained in accordance with Condition 3.4.1. The permittee must monitor and collect data according to 40 CFR 63.10020 and the site-specific monitoring plan required in Condition 4.1.1.
[40 CFR 63.10020(a) and (b)]

4.2.2. The permittee shall install, calibrate~~s~~, maintain, and operate an "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A of Part 60 be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under 40 CFR 60.49Da(b)(1). The permittee shall use the output data from the "as fired" system and SO_2 CEMS to determine compliance with the percent SO_2 reduction of Condition 4.1.1.b.ii. in accordance with 40 CFR §60.50Da(c) on daily and 30 successive boiler operating days basis. Such records of this monitoring system, data collected, and calculated values shall be maintained in accordance with Condition 3.2.1.
[40 CFR §§60.49Da(b) & (b)(3), and §§60.50Da(a) & (c)]

4.3. Testing Requirements

4.3.1. If the permittee elects to demonstrate that CFB #1 and CFB #2 qualify as low emitting EGU (LEE) for PM in accordance with 40 CFR 63.10005(h), the permittee shall conduct a performance test ~~by~~ at least once every 36 calendar months to demonstrate continued LEE status. The permittee must conduct all required performance tests described in 40 CFR §63.10007 to demonstrate that a unit qualifies for the LEE status. If the permittee ~~satisfactory~~satisfactorily demonstrates that ~~the~~ both units qualify as LEE units for PM, then ~~that~~ the PM portion of the site specific monitoring plan of Condition 4.1.1.~~k~~l and the monitoring of Condition 4.2.1.g are stayed until the unit no longer qualifies as a LEE unit for filterable PM. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, ~~LEE status is lost.~~ the permittee must conduct PM emissions testing quarterly in accordance with Condition 4.2.1.g.iii.
[40 CFR §63.10000(c)(1)(iv), §63.10006(b)(1), and §63.10020(d)(3)(i)]

When conducting emissions testing to demonstrate LEE status, the permittee must increase the minimum sample volume specified in Table 2 to Subpart UUUUU~~U~~ of Part 63 nominally by a factor of two.

For Hg, the permittee must conduct a 30-boiler operating day performance test using Method 30B in appendix A-8 to Part 60 of Chapter 40 to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. The permittee may use a pair of sorbent traps to sample the stack gas for no more than 10 days.
[40 CFR 63.10005(h)(3)]

For affected units meeting the LEE requirements of 40 CFR §63.10005(h), the permittee must repeat the performance test once every 3 years for filterable PM and once every year for Hg according to Table 5 to Subpart UUUUU of Part 63 – Performance Testing Requirements and 40 CFR §63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, ~~LEE status is lost. If this should occur,~~ then the permittee must conduct PM emissions testing quarterly in accordance with Condition 4.2.1.g.iii.
[40 CFR §§63.10006(b) & (b)(1)]

~~For losing~~ If the affected units do not quality for Hg LEE status, then the permittee must install, certify, maintain, and operate an Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this S~~s~~ubpart UUUUU~~subpart,~~ within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the permittee must conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1). The permittee must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.
[40 CFR §63.10006(b)(2)]

Such testing shall be conducted in accordance with Condition 3.3.1. with notifications and reports submitted in accordance with Condition 4.5.4 and 4.5.5.
[40 CFR §63.10030(d), §§63.10031(f), (f)(5) and (f)(6)]

4.3.2. The permittee shall conduct performance testing to measure~~d~~ CO emissions from the CFB boilers concurrently with the initial PM testing effort for the boilers to qualify as a LEE unit under Subpart UUUUU or within 180 days of after completion of installation~~install~~ of the SNCR system on each boilers, and once every three years thereafter. Such testing shall ~~testing shall~~ be

conducted to demonstrate compliance with the CO emission limits in Condition 4.1.1.d. while the SNCR system is operating. ~~to achieve lowest projected NO_x rate on 30 day rolling average for the ozone season while the unit is within ± 10% of full load conditions. This testing shall be conducted using Method 10, 10A or 10B and any other methods reference in the noted test methods and in accordance with Condition 3.3.1.~~
[45 CSR 13-5.11]

Commented [DT8]: Why is this being required?

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit, and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. For Subpart UUUUU for the CFB boilers, the permittee shall maintain records of following:

a. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §40 CFR 63.10(b)(2)(viii).
[40 CFR §63.10032(a)(2)]

b. For each PM or Hg CEMS and PM CPMS, the permittee must keep records according to the following if applicable:

i. Records described in 40 CFR §63.10(b)(2)(vi) through (xi).

ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR §63.8(d)(3).

iii. Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

[40 CFR §§63.10032(b)(1) though (b)(4)]

c. The permittee must keep the records required in Table 7 to Subpart UUUUU of Part 63 including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to the permittee.
[40 CFR §63.10032(c)]

d. For each EGU subject to an emission limit, the permittee must also keep the following records:

i. Monthly fuel usage for each CFB boiler, including the type(s) of fuel and amount used.
[40 CFR 63.10032(d)(1) and 45CSR§2A-7.1.a.]

ii. For the CFB boilers that qualifyies~~qualifies~~ as an LEE status under §63.10005(h), the permittee must keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant (filterable PM and/or Hg), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.
[40 CFR 63.10032(d)(3)]

e. Regarding startup periods or shutdown periods:

i. The permittee must keep records of the occurrence and duration of each startup or shutdown;

~~ii. The permittee must keep records of the determination of the maximum clean fuel capacity for each EGU;~~

~~iii. The permittee must keep records of the determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and~~

~~iv. The permittee must keep records of the information required in 40 CFR §63.10020(e), which are the following:~~

1. ~~The date and time that clean fuels being combusted for the purpose of startup begins; (ii) The quantity and heat input of clean fuel for each hour of startup;~~

2. ~~The electrical load for each hour of startup;~~

3. ~~The date and time that non-clean fuel combustion begins; and~~

4. ~~The date and time that clean fuels being combusted for the purpose of startup ends. (2) During each period of shutdown, The permittee must record for each EGU:~~

5. ~~The date and time that clean fuels being combusted for the purpose of shutdown begins;~~

6. ~~The quantity and heat input of clean fuel for each hour of shutdown;~~

7. ~~The electrical load for each hour of shutdown;~~

8. ~~The date and time that non-clean fuel combustion ends; and~~

9. ~~The date and time that clean fuels being combusted for the purpose of shutdown ends.~~

[40 CFR §§63.10032(f)(1) through (f)(4) and §§63.10020(e)(1) and (e)(2)]

NRG note: As part of a suite of proposed technical corrections to the rule (see FR 80 [31] 02-17-2015, pages 8442-8484), EPA intends to clarify that the information per §63.10031(c)(5) is required to be included in the compliance report only if the affected source elects to meet the work practice standards contained in paragraph (2) of the definition of startup (i.e., the "alternate" definition of startup). Pursuant to correspondence with EPA (attached herein), EPA expected to finalize the technical corrections to the rule in Summer 2015. EPA's target date was postponed to November 2015, and then postponed again to February 2016 (current target). MEA plans to meet the work practice standards contained in paragraph (1) of the definition of startup.

Page 8447: 46. Section 63.10031(c)(5) is revised to clarify that it applies only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.

Page 8447: 49. Section 63.10032(f) is revised to clarify that the requirements of § 63.10032(f)(1) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (1) of the definition of startup, while the requirements of § 63.10032(f)(2) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.

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* * * * *

(c) * * *

(4) Include the date of the most recent tune-up for each EGU. For the first tuneup, include the date of the burner inspection if it was delayed.

(5) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, for each instance of startup or shutdown you shall: .....

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* * * * *

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of "startup" in § 63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.
(2) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, you must keep records of:
(i) The determination of the maximum clean fuel capacity for each EGU;
(ii) The determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and
(iii) The information required in § 63.10020(e).

f. The permittee must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment.
[40 CFR §63.10031(g)]

g. The permittee must keep records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 CFR §63.10031(h)]

~~h. The permittee must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.~~
~~**[40 CFR §63.10031(i)]**~~

~~i.~~h. The permittee may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR §§63.10000(c)(1)(vi)(B) and 40 CFR §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out -of-control periods, repairs associated with monitoring system malfunctions or monitoring system out -of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system.
[40 CFR §63.100020(b)]

~~j.~~i. Except for periods of monitoring system malfunctions or monitoring system out -of-control periods, repairs associated with monitoring system malfunctions or monitoring system out -of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.
[40 CFR §63.10020(d)]

4.4.5. The permittee shall calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years ~~following resumption of regular operations after the change in method of operation to achieved compliance with the SO_2 of the Subpart UUUUU to Part 63 of Chapter 40~~ for NO_X, CO, PM, PM_{10}, and $PM_{2.5}$ from CFB boilers (S009J and S009K).
[45 CSR §14-19.8c.]

4.4.6 The permittee shall determine and record the ash and Btu content of the coal received at the facility. Such records shall be maintained in accordance with Condition 3.4.1. of this permit.
[45CSR§2A-7.1.a.4.]

4.4.7. The ~~permitted~~ permittee shall record and maintain records as specified in the following for the two auxiliary boilers:

a. The amount of natural gas combusted during each day and calculate the annual capacity factor. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

~~b. the NO_X standards under 40 CFR §60.44b shall maintain records of the following information for each steam generating unit operating day:~~

~~i. Calendar date;~~

~~ii. The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;~~

~~iii. The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;~~

~~iv. Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under 40 CFR §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;~~

~~v. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;~~

~~vi. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;~~

~~vii. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;~~

~~viii. Identification of the times when the pollutant concentration exceeded full span of the CEMS;~~

~~ix. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with~~

~~x. Performance Specification 2 or 3; and~~

~~xi.~~i. ~~Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.~~

Commented [DT9]: There are no CEMS on the aux boilers, these requirements are streamlined in the Title V permit.

~~c.~~b. All records shall be maintained in accordance with Condition 3.4.1.
[40 CFR 60.49b(d)(1) & (g)]

4.5. Reporting Requirements

4.5.1. For Subpart Da Reporting for SO2 and PM from the CFB boilers, the permittee shall submit reports to the Director and Administrator semiannually. The reporting periods shall begin on January 1 and July 1 with the end of the reporting periods ending on June 30 and December 31 respectively. These reports shall be postmarked by 30 day following the end of the reporting period. Such reports shall contain the following information.

a. For SO_2, the following information is reported to the Director for each 24-hour period.

i. Calendar date.

ii. The average SO_2 emission rates (lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

iii. The percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

iv. Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

v. Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

vi. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

vii. Identification of the times when the pollutant concentration exceeded full span of the CEMS.

viii. Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

ix. If the minimum quantity of emission data as required by 40 CFR §60.49Da (Condition 4.2.1.) is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of 40 CFR §60.48Da(h) is reported to the Administrator for that 30-day period:

1. The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

2. The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

3. The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.

4. The applicable potential combustion concentration.

5. The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

x. For any periods for which opacity, SO_2 or NO_X emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

xi. The responsible official of permitted facility shall submit a signed statement indicating whether:

1. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

2. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

3. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

4. Compliance with the standards has or has not been achieved during the reporting period.

xii. For the purposes of the reports required under 40 CFR §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.
[40 CFR §60.19(d) and §§60.51Da(b), (c), f), (h), and (i)]

~~4.5.2. Subpart Db Reports for Auxiliary Boilers, the permittee shall submit excess NO_x emissions and compliance reports to the Administrator and Director on a semi-annual basis. The reporting periods shall begin on January 1 and July 1 with the end of the reporting periods ending on June 30 and December 31 respectively. These reports shall be postmarked by 30 day following the end of the reporting period.~~

~~For the purpose of excess NO_x emissions in this report are defined as any calculated 30-day rolling average NO_x emission rate, determined under 40 CFR §60.46b(e), that exceeds the 0.20 lb of NO_x per MMBtu of heat input.~~

Commented [DT10]: 0.189?

~~Such reports shall contain all the recorded information during the reporting period as required in Condition 4.4.6.~~
~~**[40 CFR §60.19(d) and §§60.49b(h), (i), and (w)]**~~

Commented [DT11]: There are no Subpart Db reports for the aux boilers, these requirements are streamlined in the Title V permit.

4.5.3. The permittee shall submit a "Notification of Compliance Status" for the CFB Boilers to the Administrator before the close of business on the sixtieth (60th) day after completion of the initial compliance or LEE demonstration as required in Conditions 4.1.1.m., 4.1.1.n. and 4.1.1.o. Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the applicable information specified in 40 CFR §§63.10030(e)(1), though (e)(8). Such notification shall be submitted reference in Conditions 4.5.

[40 CFR §63.9(h)2(ii), §63.1005(k), §63.10011(e), §63.10030(e)

4.5.4. Subpart UUUUU Reports for CFB boilers, the permittee must submit each report in Table 8 to Subpart UUUUU of Chapter 40 that applies to the CFB boilers. If continuously ~~monitor~~monitored Hg emissions are required to be used to demonstrate compliance with Condition 4.1.1.f., the permittee must also submit the electronic reports required under Appendix A to Subpart UUUUU, at the specified frequency.

The first compliance report must cover the period beginning on April 16, 2016 and ending on December 31, 2016.

The first compliance report must be postmarked or submitted electronically no later than January 31, 2017.

Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

The compliance report must contain the following information (40 CFR§§ 63.10031(c)(1) through (5)):

a. The information required by the summary report located in 40 CFR §63.10(e)(3)(vi).

b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non- waste determination by EPA or the permittee basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

c. Indicate whether the permittee burned new types of fuel during the reporting period. If the permittee did burn new types of fuel the permittee must include the date of the performance test where that fuel was in use.

d. Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to §63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 months and was delayed until the next scheduled unit shutdown.

~~e. For each instance of startup or shutdown:~~

~~i. Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of 40 CFR §63.10032(f).~~

~~ii. Include the information required to be monitored, collected, or recorded according to the requirements of Condition 4.4.5. (40 CFR §63.10020(e)).~~

~~iii. If the permittee choose to use CEMS for compliance purposes, include hourly average CEMS values and hourly average flow rates. Use units of milligrams per cubic meter for PM CEMS, micrograms per cubic meter for Hg CEMS, and ppmv for HCl, HF, or SO_2 CEMS. Use units of standard cubic meters per hour on a wet basis for flow rates.~~

~~iv. If the permittee choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration in terms of micrograms per cubic meter.~~

~~v.~~i. ~~If the permittee choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.~~

~~f.~~e. For each excess emissions occurring at an affected source where the permittee is using a CMS to comply with that emission limit or operating limit, the permittee must include the information required in 40 CFR §63.10(e)(3)(v) in the compliance report specified in 40 CFR §63.10031(c).

4.5.5. Prior to April 16, 2017, all ~~report~~reports subject ~~be~~ to electronic submissions in 40 CFR §§63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs of 40 CFR §§63.10031(f) in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:

a. The facility name, physical address, mailing address (if different from the physical address), and county;

b. The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;

c. The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;

d. If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of this chapter;

e. If any of the EGUs described in 40 CFR §63. ~~100XX~~10031(f)(6)(iii) of this section are in an averaging plan under 40 CFR §63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;

f. The identification of each emission point to which the report applies. An "emission point" is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (e.g., "Unit 2 stack," "common stack CS001," or "multiple stack MS001");

g. The rule citation (e.g., §63.10031(f)(1), §63.10031(f)(2), etc.) for which the report is showing compliance;

h. The pollutant(s) being addressed in the report;

i. The reporting period being covered by the report (if applicable);

j. The relevant test method that was performed for a performance test (if applicable);

k. The date the performance test was conducted (if applicable); and

l. The responsible official's name, title, and phone number.
[40 CFR §§63.10031(f)(6)]

4.5.6. On or after April 16, 2017, the permittee shall reports of the following activates as required under Subpart UUUUU of Part 63 in accordance with the corresponding regulation:

a. Performance testing shall be submitted in accordance with 40 CFR §63.10031(f);

b. Each CEMS performance evaluation and relative accuracy test audit for the CEMS in accordance with 40 CFR §63.10031(f)(1)

c. PM CEMS or PM CPMS data in accordance with 40 CFR §63.10031(f)(2)

d. Notification of Compliance Status and Compliance Report as required in Condition 4.5.3. in accordance with 40 CFR 63.10031(f)(3).
[40 CFR §§63.10031(f), (f)(1), (f)(2), (f)(4)]

4.5.7. All reports required by Subpart UUUUU~~U~~ not subject to the requirements in 40 CFR §§63.100031, paragraphs (f) introductory text and (f)(1) through (4) (Condition 4.5.5.) must be sent to the Administrator and Director in accordance with Condition 3.5.1.. If acceptable to both the Administrator and the permittee, these reports may be submitted on electronic media. The Administrator and Director retains the right to require submittal of reports subject to 40 CFR §§63.100031, paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.
[40 CFR 63.10031(f)(5)]

4.5.7. The permittee shall submit "Annual Compliance Reports" to the Director for the Auxiliary Boilers with the first report being submitted no later than January 31, 2017, and subsequent reports are due every year thereafter. Such reports shall contain the information specified in 40 CFR §§63.7550(c)(5) (i)through (iv) and (xiv) which are:

a. Permittee and facility name, and address;

b. Process unit information, emission limitations, and operating limitations;

c. Date of report and beginning and ending dates of the reporting period;

d. The total operating time during the reporting period of each affected unit;

e. Include the date of the most recent tune-up for the boiler; and

f. Include the date of the most recent burner inspection if it was not done within the specified time schedule and was delayed until the next scheduled or unscheduled unit shutdown.
[40CFR §§63.7550(b), (b)(1), (c)(1), & (c)(5)(i) though (iv) and (xiv)

5.0. Fuel, Limestone, and Ash Handling

5.1. Limitations and Standards

5.1.1. Coal/coal refuse and limestone handling/storage facilities shall consist of the following, and particulate emissions shall be controlled as specified with maximum particulate emissions not to exceed the following:

	Type/Identity of Particulate Matter Control Equipment	Particulate Emission Limitation for Control Equipment Discharge lb/hr
Coal/Gob Receiving Hoppers (Truck)	Enclosure and Water/Chemical Dust Suppression System	
Coal/Gob Receiving Hopper (Emergency Use)	Minimize Drop Height	
Elevating Transfer Conveyor No. 1, Two Fuel Silos, Reversible Silo Feed Conveyor, Hopper Transfer Conveyor, and Transfer Points	Enclosure and Evacuation to Baghouse	0.0002
Elevating (Tripper) Conveyor No. 2 (top), Two Fuel Day Bins, and Transfer Points	Enclosure and Evacuation to Baghouse	0.0002
Mill Collecting Conveyor, Elevating Conveyor No. 2 base	Enclosure and Evacuation to Baghouse	0.0002
Two Coal/Gob Crushers (Grinding Mill, Hammer Mill), Emergency Fuel Feed Conveyor, Weigh Belt Conveyor	Enclosure and Evacuation to Baghouse	0.099
One 1,160 Ton Limestone Storage Silo	Baghouse	0.014
Limestone Truck Unloading Hopper	Enclosure and Evacuation to Baghouse	0.027
One Limestone Day Bin	Baghouse	0.005

5.1.2. Ash transfer, storage and loading facilities shall consist of the following and particulate emissions from the entire system shall be controlled as specified with maximum particulate emissions not to exceed the following:

	Type/Identity of Particulate Matter Control Equipment	Particulate Emission Limitation for Control Equipment Discharge lb/hr
Pneumatic System for Collected Flyash and Bottom Ash Handling, One 1300 Ton Ash Silo, Vacuum Blowers	Enclosure and Evacuation to Baghouse	0.028
Fully Sealed Mechanical System for Bottom Ash/Cooler Rejects, One 85 Ton Bottom Ash Silo	Baghouse	0.028
Flyash Transport (Silo Vent)	Baghouse	0.184
Wet Ash Loadout (Flyash and Bottom Ash)	Rotary dustless (wet) unloaders shall thoroughly wet ash prior to loading and handling. Ash	

	loadout(s) shall be fully enclosed and evacuated to an ash silo baghouse during all ash loading.	

5.1.3. All fugitive particulate matter control systems shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter.

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ______________________________, representing the period beginning ____________________ and ending ____________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ____ ____________________
(please use blue ink) Responsible Official or Authorized Representative Date

Name & Title ____________________________ ____________________________
(please print or type) Name Title

Telephone No. ________________________ Fax No. ________________________

[1] This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

(ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.

FEDERAL REGISTER

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Part III

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Revisions; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234 and EPA–HQ–OAR–2011–0044; FRL–9921–04–OAR]

RIN 2060–AS41

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Revisions

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is proposing this action to correct and clarify certain text of the final action titled "National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," which was published in the **Federal Register** of Thursday, February 16, 2012. We are also proposing to remove rule provisions establishing an affirmative defense for malfunction events in light of a recent court decision on the issue.

DATES: *Comments.* Comments must be received on or before April 3, 2015.

Public Hearing. If anyone contacts the EPA requesting a public hearing by February 23, 2015, the EPA will hold a public hearing on March 4, 2015 from 1 p.m. (Eastern Standard Time) to 5 p.m. (Eastern Standard Time) at the U.S. Environmental Protection Agency building located at 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. If the EPA holds a public hearing, the EPA will keep the record of the hearing open for 30 days after completion of the hearing to provide an opportunity for submission of rebuttal and supplementary information.

ADDRESSES: Submit your comments, identified by Docket ID. No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP/MATS action), by one of the following methods:

- *Federal rulemaking portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Agency Web site: http://www.epa.gov/oar/docket.html.* Follow the instructions for submitting comments on the EPA Air and Radiation Docket Web site.
- *Email:* Comments may be sent by electronic mail (email) to *a-and-r-docket@epa.gov,* Attention EPA–HQ–OAR–2011–0044 (NSPS action) or EPA–HQ–OAR–2009–0234 (NESHAP/MATS action).
- *Fax:* Fax your comments to: (202) 566–9744, Docket ID No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP/MATS action).
- *Mail:* Send your comments on the NESHAP/MATS action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 28221T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Docket ID No. EPA–HQ–OAR–2009–0234. Send your comments on the NSPS action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Docket ID. No. EPA–HQ–OAR–2011–0044.
- *Hand Delivery or Courier:* Deliver your comments to: EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holiday), and special arrangements should be made for deliveries of boxed information.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. Barrett Parker, Measurement Policy Group, Sector Policies and Programs Division, (D243–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5635; Fax number (919) 541–3207; email address: *parker.barrett@epa.gov.* For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION:

Comment Instructions. All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. All comments will be posted without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Public Hearing. If requested by February 23, 2015, we will hold a public hearing on March 4, 2015, from 1 p.m. (Eastern Standard Time) to 5 p.m. (Eastern Standard Time) at the U.S. Environmental Protection Agency building located at 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Please contact Ms. Pamela Garrett of the Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: 919–541–7966; email address: *garrett.pamela@epa.gov;* to request a hearing, register to speak at the hearing or to inquire as to whether or not a hearing will be held. The last day to pre-register in advance to speak at the hearing will be March 2, 2015. Additionally, requests to speak will be taken the day of the hearing at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, we ask that you pre-register for the hearing, as we may not be able to arrange such accommodations without advance notice. The hearing will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because this hearing is being held at a U.S. government facility, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. If your driver's license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma or the State of Washington, you must present an additional form of identification to enter the federal building. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver's licenses and military identification cards. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons. The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. Verbatim transcripts of the hearing and written statements will be included in the docket for the rulemaking. The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearing to run either ahead of schedule or behind schedule. Again, a hearing will not be held on this rulemaking unless requested. A hearing needs to be requested by February 23, 2015. Again, please contact Ms. Pamela Garrett of the Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: 919–541–7966; email address: *garrett.pamela@epa.gov* to request a hearing.

Docket. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (*e.g.,* CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

I. Technical Corrections

The final Clean Air Act (CAA) rules published in the **Federal Register** on February 16, 2012 (77 FR 9303), establish national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs), referred to as "the Mercury and Air Toxics Standards" or "MATS," and new source performance standards (NSPS) for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units, referred to as the Utility NSPS.

In this document, the EPA proposes to correct certain regulatory text. The proposed corrections can be categorized generally as follows: (a) Resolution of conflicts between preamble and regulatory text, (b) corrections that we stated we would make in response to comments that were inadvertently not made, and (c) clarification of language in regulatory text. Below, we identify each proposed technical correction to the regulatory text as found in the Code of Federal Regulations (*i.e.,* 40 CFR). The EPA is soliciting comments on all of these proposed corrections.

1. Section 60.49Da(f) is revised to amend the procedures for calculating compliance with the NSPS daily average particulate matter (PM) emission limit for affected facilities using PM continuous emission monitoring systems (CEMS) and that commenced construction, modification, or reconstruction before May 4, 2011. Even though it was not included in the proposal, in an effort to clarify certain language in 40 CFR 60.48Da(f), we amended the procedure for calculating compliance with the daily average PM limit for affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, using PM CEMS (78 FR 24073; April 24, 2013). The amendments removed the provision that for operating days with less than 18 hours of PM CEMS data, the data for that day would be rolled into the following operating day(s) until 18 hours of data are available. The intent of the original language was to assure that compliance with the daily PM emission rate was not determined with significantly less than 24 hours of data, but that all emissions data would still be used. The intent of the revised data was to eliminate the requirement to roll emissions data recorded on days without sufficient data to determine a daily average to the following operating day, but that a minimum of 18 hours would still be required to determine compliance with the daily PM standard. Industry requested reconsideration stating that they did not have an opportunity to comment on the issue, and that the revised calculation procedures could in fact require compliance determinations with significantly less than 24 hours of data. The proposed revisions would undo those changes and return the calculation procedures to the approach used prior to April 24, 2013. Specifically, for operating days with less than 18 hours of PM CEMS data, that data would be rolled into the following operating day(s) until over 18 hours of data are available to determine compliance with the operating day standard. We are soliciting comment on whether the intent of the current calculation procedures should be maintained (*i.e.,* data collected on days with less than 18 hours of data would not be used to determine compliance with the PM standard and would also not be rolled into the following operating day(s)). If the current approach is maintained, the regulatory language would be revised to avoid situations where compliance calculations would be made with less than 18 hours of data.

2. Section 63.9983(a) is revised to clarify that MATS does not apply to either major or area source combustion turbines, except for integrated gasification combined cycle (IGCC) units. In the final MATS rule, 40 CFR 63.9983(a) exempted from MATS "any unit designated as a stationary combustion turbine, except an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY." Because area source stationary combustion turbines are not subject to subpart YYYY, which is applicable to stationary combustion turbines located at major sources, the Agency received questions concerning the applicability of MATS to the area

source units in that category. The EPA intended by the exemption to exempt all stationary source combustion turbines other than IGCC units from the requirements of MATS, because the EPA does not interpret the statute to include those units within the definition of EGU in CAA section 112(a)(8). The proposed revisions to the regulations will clarify the EPA's interpretation and intent and prevent future confusion concerning the applicability of the MATS rule to stationary combustion turbines located at area sources.

3. Section 63.9983(b) and (c) is revised consistent with the definitional changes discussed below. The definitional changes are being proposed so that sources will know the time period to consider when determining whether their coal or oil utilization triggers applicability of the MATS rule. As explained below, the change is particularly important in the first 3 years after the compliance date when sources will be required to estimate coal and oil utilization in their EGUs to determine applicability of the MATS rule.

4. Section 63.9983(e) is added to clarify CAA section 112 applicability to the units that meet the definition of a natural gas-fired EGU in MATS, and, because they combust greater than 10 percent biomass, also meet the definition of a biomass-fired boiler in the Industrial Boiler NESHAP (40 CFR part 63, subpart DDDDD). These overlapping definitions led to confusion in the regulated community about whether such units are natural gas-fired EGUS pursuant to MATS or biomass-fired boilers subject to the Industrial Boiler NESHAP. We are revising the MATS rule to make clear that such units are biomass-fired boilers subject to the industrial boiler NESHAP. Similar revisions to the applicability provisions of the Industrial Boiler NESHAP have been proposed.[1]

5. Section 63.9991(c)(1) and (2) is being revised to clarify the conditions that are required in order to use the alternate sulfur dioxide (SO_2) limit.

6. Sections 63.10000(c)(1)(i)(A) and 63.10005(h) are revised to clarify the provisions of units designated as being low emitting EGUs (LEE) when an acid gas scrubber and a bypass stack are present.

7. Section 63.10000(c)(1)(i)(C) is added to allow EGUs the ability to seek LEE status if their bypass stacks vent through stacks that are able to measure emissions. In addition, the proposed language would allow EGUs with LEE status the ability to bypass emissions control devices during emergency periods provided certain fuel and time restrictions, along with notification requirements, occur.

The final MATS rule did not allow EGUs whose emissions control devices had bypasses to seek LEE status. Owners and operators of EGUs whose emissions control devices had no bypass stacks, but instead routed bypass emissions through main stacks equipped with emissions measurement capability, requested that we allow their EGUs to seek LEE status provided emissions were measured during bypass events. We believe that EGU owners or operators that have the ability to measure and report emissions during bypass events should be able to seek LEE status as long as bypass emissions are included in the calculations required to demonstrate the LEE status eligibility. For this reason, we are proposing to allow this option.

Also, a number of EGU owners or operators requested that we allow EGUs with LEE status the ability to bypass their emissions control devices in emergency conditions, provided that the EGUs were combusting clean fuels and that the bypass periods were of short duration.[2] We reviewed the requests and believe that control device bypass operation for up to 2 percent of EGU operating hours while combusting clean fuel during emergency periods is reasonable, provided a report detailing the emergency event, its cause, the corrective action taken to alleviate the emergency event, and estimates of the emissions released during the emergency event are provided. In addition, an EGU owner or operator must include these emergency emissions along with performance test results in assessing whether its EGU maintains LEE status. We seek comment on the adequacy of the restrictions associated with bypass conditions regarding maintaining LEE status.

8. Section 63.10000(c)(2)(iii) is revised to state that EGU owners or operators who choose to use quarterly testing and parametric monitoring for hydrogen fluoride (HF) or hydrogen chloride (HCl) compliance must include the continuous monitoring systems (CMS) that will be used in their site-specific monitoring plans to comply with the monitoring requirements.

9. Section 63.10000(m) is added to clarify that EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used to generate data to meet the work practice standards. Moreover, this addition clarifies that those monitoring systems may be installed, verified, operated, maintained, and quality assured using manufacturer's specifications.

10. Section 63.10001 is revised to remove the affirmative defense provisions as explained in Section II below. The section is reserved.

11. Section 63.10005(a) is revised to clarify that different compliance demonstrations may require different and additional types of data collection and to clarify the date by which compliance must be demonstrated for existing EGUs.

12. Section 63.10005(a)(2) is revised to clarify the date by which compliance must be demonstrated for EGUs using CMS or sorbent trap monitoring systems.

13. Section 63.10005(a)(2)(i) is revised to clarify applicability of the provision to both the 30- and 90-boiler operating day performance testing requirements.

14. Section 63.10005(b)(1) is revised to clarify the time period allowed for existing EGUs to use stack test data collected prior to the applicable compliance date.

15. Section 63.10005(b)(6) is added to clarify the date EGUs must begin conducting required stack tests when stack test data collected prior to the applicable compliance date are submitted to satisfy the initial performance test requirement.

16. Section 63.10005(d)(3) and (d)(4)(i) is revised to more clearly state when compliance must be demonstrated.

17. Section 63.10005(f) is revised to clarify when sources must complete the initial boiler tune-up after the compliance date, and the timing for subsequent tune-ups when a tune-up conducted prior to the compliance date is used to satisfy the initial tune-up requirement.

18. Section 63.10005(h)(3) is revised to clarify that the alternate 30- and 90-day averaging provisions are both applicable to mercury (Hg) emission limits, and to clarify the sampling probe location.

19. Section 63.10005(i)(4) is revised to delete paragraphs (iii) and (iv). The identified test methods contain requirements for fuel sampling, not determining fuel moisture content, as required in the provision.

[1] Prepublication version found at *http://www.epa.gov/ttn/atw/boiler/boilerpg.html*. The prepublication version will be replaced with the **Federal Register** document when the proposal is published.

[2] To the extent these EGUs bypassed their control devices without measuring emissions, the hours of bypass operation would need to be reported as hours of monitoring deviation and subject to potential enforcement action.

20. Section 63.10006(f) is revised to specify EGU operational status with respect to performance testing; to identify the requirements—including make-up testing and reporting—if the performance testing schedule is missed apart from using existing skip procedures; and to identify intervals between performance tests. The final MATS rule had no provision that allowed an EGU owner or operator to skip a required performance test if its EGU was otherwise not operating; we did not believe the rule needed to be explicit in stating that EGUs need not be turned on solely to conduct performance testing. However, we have received questions regarding this circumstance. We believe it is appropriate to allow an EGU owner or operator the ability to skip a required performance test if its EGU is not otherwise operating, and are proposing this in this action. The final MATS rule had no provisions regarding make-up testing and reporting should a regularly scheduled performance test be missed for reasons other than the existing skip procedures. We believe it is appropriate to specify a schedule for required make-up testing and reporting, and are proposing such a schedule in this action. The final MATS rule specified the time periods between performance tests, but EGU owners or operators expressed concerns about being able to adhere to such a schedule. We believe their concerns about having too tight a timeline for retesting to occur and our concern about having a sufficient interval of time between tests such that the results better reflect characteristics of different periods can be addressed by specifying a minimum interval of time between subsequent performance tests, which we are proposing in this action. We welcome comments as to the need for, as well as efficacy of, these proposed revisions, as well as on these proposed intervals.

21. Section 63.10009(a)(2) and (a)(2)(i) is revised to clarify that the 90-boiler operating day averaging period is available as an option for Hg emissions from non-low rank virgin coal-fired EGUs (*i.e.*, EGUs in the subcategory "unit designed for coal ≥8,300 Btu/lb"). In the final MATS (77 FR 9303 at 9385), we had indicated that we were providing the 90-boiler operating day averaging period as an alternative compliance approach (to the standard 30-boiler operating day averaging period) for Hg emissions from EGUs in that subcategory. However, the regulatory text in 40 CFR 63.10009(a)(2) did not clearly reflect this option. The term "gross electric output" is also corrected to "gross output" which is the term defined in 40 CFR 63.10042.

22. Section 63.10009(b)(1) is revised to clarify group eligibility equations 1a and 1b. These equations were developed to provide EGU owners or operators a quick method for determining if their emissions averaging group could meet the emissions limit when operated at the maximum rated heat input and, in some cases, steam production. Commenters reported difficulty in using the equations in the final rule, so the equations have been revised so that individual EGU characteristics, whether from CEMS or stack testing results, are easier to input. We request comment on the proposed revisions concerning their usefulness in calculating the maximum potential emissions rate from an emissions averaging group. The term "gross electric output" is also corrected to "gross output" which is the term defined in 40 CFR 63.10042.

23. Section 63.10009(b)(2) and (3) is revised to correct the term "gross electric output" to "gross output" which is the term defined in 40 CFR 63.10042.

24. Section 63.10009(f) is revised to clarify the conditions for determining the ability of the emissions averaging group to meet the emissions limit and to clarify use of the alternate Hg emission limit. Instead of relying on the maximum normal operating load of each EGU in determining the ability of the emissions averaging group to demonstrate initial compliance, as was contained in the final MATS rule, we are proposing in this action to use the maximum possible heat input or gross output of each EGU in determining the ability of the emission averaging group to demonstrate initial compliance. In addition, instead of calculating the maximum weighted average emissions rate, as used in the final MATS rule, we are proposing in this action to calculate the initial weighted average emissions rate. Finally, instead of specifying just one date for submitting an emissions averaging plan, as was done in the final MATS rule, we are proposing in this action to allow an EGU owner or operator the flexibility to choose other dates to begin using an emissions averaging plan by allowing the submission of an emissions averaging plan at least 120 days before the date on which emissions averaging is to begin. We believe these changes will provide additional flexibility without undermining the enforceability of the final standards.

25. Section 63.10009(f)(2), (g)(1), (g)(2), and (j)(1)(ii) is revised to correct the term "gross electric output" to "gross output" which is the term defined in 40 CFR 63.10042.

26. Section 63.10010(a)(4) is revised to add a requirement to route exhaust gases that bypass emissions control devices through stacks that contain monitoring so that emissions can be measured and to clarify that hours that a bypass stack is in use are to be counted as hours of deviation from monitoring requirements.

27. Section 63.10010(f)(3) is revised to clarify that 30-boiler operating day rolling averages are to be based only on valid hourly SO_2 emission rates.

28. Section 63.10010(h)(6)(i) and (ii), (i)(5)(A) and (B), and (j)(4)(i)(A) and (B) is revised to clarify that data collected during certain periods are not to be included in compliance assessments but such periods are to be included in annual deviation reports. The final MATS rule established that all data collected with PM CPMS, PM CEMS, and HAP metals CEMS during all boiler operating hours were to be used in assessing compliance except those data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, required quality assurance or quality control activities, or monitoring out-of-control periods. In addition, the final MATS rule sections combined the requirement to report the periods when data collected during these operating periods as deviations into one long sentence. In this action, we are proposing to separate these requirements into two sentences to ease readability.

29. Section 63.10010(l)(i) is revised to replace the incorrect reference to § 63.7(e) with the correct reference to § 63.8(d)(2).

30. Section 63.10010(l) and (l)(4) is revised to clarify that EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used to generate data to meet the work practice standards. Moreover, this revision clarifies that those monitoring systems may be installed, verified, operated, maintained, and quality assured using manufacturer's specifications.

31. Section 63.10011(b) is revised to remove the incorrect reference to Table 4 and to replace the incorrect reference to Table 7 with the correct reference to Table 6.

32. Section 63.10011(c)(1) and (2) is revised to clarify the date by which compliance must be demonstrated by EGUs that use CEMS or sorbent trap monitoring systems. In addition, § 63.10011(c)(1) is revised to clarify that

the alternate Hg emission limit may be used.

33. Section 63.10011(e) is revised to replace "according to" with "in accordance with."

34. Section 63.10011(g)(4)(v)(A) and Table 3 are revised to clarify our intent regarding clean fuel use "to the maximum extent possible." Our goal in the work practice is to minimize HAP emissions during startup and shutdown periods, and that goal can be accomplished by minimizing primary fuel use and maximizing clean fuel use because of the inherently low HAP content of the defined "clean fuels." As stated in the preamble to the final startup and shutdown reconsideration rule, EGUs that chose to comply with the alternative work practice will be required to have sufficient clean fuel capacity to startup and warm the facility to the point where the primary PM controls can be brought on line at the same time as, or within 1 hour of, the addition of the primary fuel to the EGU. 79 FR 68777 at 68779, November 19, 2014. We recognize that the clean fuel requirement may require sources to increase clean fuel capacity, modify the startup burners, and/or take additional actions to comply with the final rule. 79 FR 68777 at 68779, November 19, 2014. Thus, we expect clean fuels to be combusted in at least the amount needed to bring the emissions control devices to operational levels necessary to comply with the numeric standards at the end of startup. We do not expect clean fuel use to the extent that it compromises the integrity of the boiler or its control devices; neither do we expect clean fuel to be combusted in excess of the amount needed to bring the emissions control devices to expected operational levels. We have determined that it is appropriate to slightly revise the language in the November 19, 2014, final rule. 79 FR 68777. The proposed revision would change the language from "to the maximum extent possible" to "to the maximum extent practicable, taking into account boiler or control device integrity."

35. Section 63.10020(e) is revised to clarify that it applies only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. In addition, the undefined term "electrical load" has been replaced with the defined term "gross output" and the incorrect terms "liquid to fuel ratio" and "the differential pressure of the liquid" in § 63.10020(e)(3)(i)(E) have been replaced with the correct terms "liquid to flue gas ratio" and "the pressure drop across the scrubber." Finally, in order to clarify our intent that existing instrumentation or engineering calculations can be used to provide flow information, § 63.10020(e)(3)(i)(A) and (B) is revised to remove the term "rate" and to acknowledge the use of existing combustion air flow monitors or combustion equations.

36. Section 63.10021(d)(3) is revised to clarify the type of monitoring that is to be used to demonstrate compliance.

37. Section 63.10021(e) is revised to clarify the condition that allows delay of burner inspections for initial boiler tune-ups.

38. Section 63.10021(e)(9)(i) and (ii) is revised to clarify the dates that tune-ups must be reported.

39. Section 63.10023(b) and Table 6 are revised to clarify that all EGUs using PM continuous parametric monitoring systems (CPMS) for compliance purposes are to follow the same procedure for determining the operating limit. The final rule allowed existing EGUs to determine the operating limit based on the highest 1-hour average PM CPMS value recorded during a performance test, even if that average time was associated with a test run in excess of the numeric standards, while new EGUs were required to use a scaling factor or the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish the operating limit.[3] We believe all EGUs should use a consistent set of procedures for both new and existing EGUs for establishing an operating PM limit, so we are proposing in this action to revise the procedures for existing EGUs. The procedures for existing EGUs, contained in § 63.10023(b)(1) are reserved, and § 63.10023(b)(2) and Table 6 are revised so that all EGUs are to follow the operating limit development procedures for new EGUs (*i.e.*, use a scaling factor or the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish the operating limit).

40. Section 63.10030(e)(1) is revised to replace the phrase "identification of which subcategory the source is in" with "identification of the subcategory of the source."

41. Section 63.10030(e)(7)(i) is revised to clarify that the date of each stack test conducted for purposes of demonstrating LEE eligibility is to be provided. The final rule establishes that each test for pollutants other than Hg conducted over a 3-year period must meet the LEE emission limit in order for an EGU to be eligible for LEE status.

42. Section 63.10030(e)(7)(iii) is added to establish the procedures by which an EGU owner or operator may switch between mass per heat input and mass per gross output emission limits. The EPA has received questions about how frequently an existing EGU could alternate between the two compliance formats. Although we did not envision that an owner or operator of an existing EGU would want to change the basis of the EGU's emission limits, we believe it is reasonable to allow such action provided certain conditions, including performance testing demonstrating compliance with the new format, submission of a written request to change formats, and receipt of permission from the Administrator to change formats, are met. We request comment on these procedures, as well as on the concept of switching emission limits, particularly during performance averaging periods.

43. Section 63.10030(e)(8)(i) is revised to clarify that it applies only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. Moreover, the provisions requiring a description of PM control device efficiencies and PM emission rates are revised to clarify that such efficiencies and emission rates are those of periods other than startup and shutdown periods. As the uncontrolled emission rates can be calculated from control device efficiencies and corresponding emission rates, the provisions requiring reporting of uncontrolled emission rates have been removed.

In addition, as current EGU characteristics are most relevant for compliance with the MATS rule, the requirements concerning identification of intermediate changes to the EGU design have been removed. In order to reduce redundant reporting, the rule has been revised to require no additional identification if no changes to the EGU's design characteristics have occurred.

Finally, § 63.10030(e)(8)(ii)(A) has been revised to remove the requirement for use of an independent professional engineer. Consistent with the discussion contained in 71 FR 16869 (April 4, 2006), we believe that a professional engineer, regardless of whether they are independent, is able to give a fair technical review because of the programs established by the state licensing boards, which serve to enforce objectivity from each registrant. We believe that the revision will allow EGUs to reduce burden without compromising environmental safety by

[3] See the description of the "third approach" at 79 FR 24708 (April 24, 2013).

using in-house expertise. Professional engineers employed by an EGU should be more familiar with its design and operational characteristics and should be in a position to expedite collection and submission of required information.

44. Section 63.10030(f) is revised to add notification requirements for EGUs that move in and out of MATS applicability.

45. Section 63.10031(c)(4) is revised to clarify the reporting requirements for EGU tune-ups.

46. Section 63.10031(c)(5) is revised to clarify that it applies only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.

47. Section 63.10031(c)(6) is revised to add emergency bypass reporting for EGUs with LEE status.

48. Section 63.10031(f)(5) is revised to state that the Administrator retains the right to require submittal of reports subject to paragraph (f)(4), as well as paragraphs (f)(1) through (3).

49. Section 63.10032(f) is revised to clarify that the requirements of § 63.10032(f)(1) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (1) of the definition of startup, while the requirements of § 63.10032(f)(2) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.

50. The definitions of "Coal-fired electric utility steam generating unit," "Coal refuse," "Fossil fuel-fired," "Integrated gasification combined cycle electric utility steam generating unit or IGCC," "Limited-use liquid oil-fired subcategory," "Natural gas-fired electric utility steam generating unit," and "Oil-fired electric utility steam generating unit" in § 63.10042 are revised to clarify the period of time to be included in determining the source's applicability to the MATS.

During the comment period on the proposed MATS rule, industry noted that many EGUs would convert to natural gas or other non-fossil fuel prior to the compliance date and those sources would remain subject to MATS because the proposed rule required sources to determine applicability based on the 3 calendar years prior to the compliance date. *See, e.g.,* 40 CFR 63.10042 (definition of "fossil fuel-fired"). The EPA agreed that this was not the EPA's intent and in the final MATS rule revised several definitions, including the definition of fossil fuel-fired, that required sources to evaluate usage after the applicable compliance date.

The EPA inadvertently created confusion in its attempt to address industry concerns in the final MATS rule. The confusion is best illustrated by an analysis of the proposed and final definitions of "fossil fuel-fired." The EPA's proposed definition stated, in part, that "[i]n addition, fossil fuel-fired means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input during the *previous 3 calendar years* or for more than 15.0 percent of the annual heat input *during any one of those calendar year.*" *See* 76 FR 24975 at 25123 (emphasis added). The intent in this definition was to require sources to look at the usage from the 3 previous years to determine if the average or the single year usage from those 3 years exceeded either of the thresholds.

To address the commenters' concern, the EPA revised the definition of "fossil fuel-fired" in the final rule to state, in part, that "[i]n addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual year input during *any 3 consecutive calendar years* or for more than 15.0 percent of the annual heat input during *any one calendar year* after the applicable compliance date." 40 CFR 63.10042 (emphasis added). This definition creates at least two potential compliance issues: (1) It creates confusion as to how sources are to determine MATS applicability during the first 3 years after the applicable compliance date; and (2) it subjects sources to MATS in perpetuity if the usage thresholds are ever exceeded after the compliance date—"any 3 consecutive calendar years" or "any one calendar year" "after the applicable compliance date."

The proposed revisions to the definitions address both issues. Concerning applicability in the first 3 years after the applicable compliance date, this proposed rule states that sources must project their coal and oil usage for the first 3 years to determine whether the EGU will exceed either the 10.0 or 15.0 percent threshold. The EPA's understanding is that sources know with sufficient specificity the fuels they will use in advance, and requiring sources to project their usage accommodates industry concerns that the sources that are converting to natural gas or biomass prior to the compliance date not be subject to MATS. The EPA is also proposing that sources that permanently convert to natural gas or biomass after the compliance date are no longer subject to MATS, notwithstanding the coal or oil usage the previous 3 calendar years.

The EPA is also proposing to revise the definitions to make clear that after the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the 3 previous calendar years on an annual rolling basis, consistent with the definition of "fossil fuel-fired" proposed in the MATS rule. This proposed change will prevent EGUs from being subject to MATS in perpetuity if they exceed the 10 or 15 percent threshold at any time after the compliance date.

A definition of "neural network" is also being added because the term is used in 40 CFR 63.10005(f), 63.10006(i), and 63.10021(e) and Table 3 to subpart UUUUU of Part 63 but is not defined.

51. Table 1 to subpart UUUUU of Part 63 is revised to correct the term "gross electric output" to "gross output" which is the term defined in 40 CFR 63.10042 in footnotes 1, 4, and 5.

52. Table 2 to subpart UUUUU of Part 63 is revised to correct the term "gross electric output" to "gross output" which is the term defined in 40 CFR 63.10042 in footnote 2. Provision 1(c) (the Hg limit for EGUs in the subcategory "unit designed for coal ≥8,300 Btu/lb") is also revised to clarify the applicability of the alternate 90-boiler operating day compliance option.

53. Table 3 to subpart UUUUU of Part 63 is revised as described earlier to clarify the term "maximum extent possible."

In addition, we have received questions concerning the interpretation of the definition of startup, particularly the language defining the end of startup. Industry has inquired whether the triggering action is either the generation of electricity or of steam for any useful purpose under both definitions of startup. The EPA does interpret the end of startup in a consistent manner as between the two definitions. Specifically, we interpret the phrase ". . . when any of the steam from the boiler is used . . . for any other purpose," contained in paragraph (1) of the definition of startup, to have the same meaning as the phrase "for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler," as provided in paragraph (2) of the definition of startup. EGUs trigger the end of startup whenever they use either electricity or steam for any useful purpose either on or offsite.

54. Table 4 to subpart UUUUU of Part 63 is revised to clarify that existing as well as new EGUs using PM CPMS share the same procedures for

developing operating limits (*i.e.*, those that are based on the higher of a parameter scaled from all values obtained during an individual emissions test to 75 percent of the emissions limit or the average parameter value obtained from all runs of an individual emission test as the operating limit provided that the result of the individual emissions test met the emissions limit requirements).

55. Table 5 to subpart UUUUU of Part 63 is revised to state that when using Method 5, you are to report the average of the final 2 filter weighings, and to clarify that when using Method 29, you are to report the metals matrix spike and recovery levels. These provisions are needed for the required electronic reporting.

56. Table 6 to subpart UUUUU of Part 63 is revised to clarify that existing, as well as new, EGUs using PM CPMS share the same procedures for developing operating limits (*i.e.*, those that are based on the higher of a parameter scaled from all values obtained during an individual emissions test to 75 percent of the emissions limit or the average parameter value obtained from all runs of an individual emission test as the operating limit provided that the result of the individual emissions test met the emissions limit).

57. Table 8 to subpart UUUUU of Part 63 is revised to clarify that compliance reports are to include information required by § 63.10031(c)(5) and (6).

58. Table 9 to subpart UUUUU of Part 63 is revised to correct an inadvertent omission of 30-day notification requirements of § 63.9.

59. Paragraphs 4.1.1.3 and 5.1.2.3 and Tables A–1 and A–2 to Appendix A to subpart UUUUU of Part 63 are revised to adjust Hg CEMS language regarding converters. Research has shown that all Hg CEMS need weekly single-level system integrity checks.

60. Paragraph 7.1.2.5 to Appendix A to subpart UUUUU of Part 63 is added to require that owners or operators flag EGUs that are part of emission averaging groups.

61. Paragraph 3.2.1.2.1 of Appendix A to subpart UUUUU of Part 63 is revised to specifically indicate that Hg gas generators and cylinders are allowed.

62. Paragraphs 4.1.1.1, Table A–1, Table A–2, 5.1.2.1, and 4.1.1.3 of Appendix A to subpart UUUUU of Part 63 are revised to exclude use of oxidized Hg gas standards for daily calibration of Hg CEMS.

63. Paragraph 5.1.2.3 of Appendix A to subpart UUUUU of Part 63 is revised to make the weekly single level system integrity check mandatory.

64. Paragraphs 4.1.1.5.2, Table A–1, Table A–2, and 4.1.1.5 of Appendix A to subpart UUUUU of Part 63 are revised to provide an alternative relative accuracy test audit (RATA) procedure for EGUs with low emissions that is related specifically to the emission standard.

65. Paragraph 5.2.1 of Appendix A to subpart UUUUU of Part 63 is revised to correct the number of days for sorbent trap use from 14 to 15.

66. Paragraph 6.2.2.3 of Appendix A to subpart UUUUU of Part 63 is revised to clarify that the 90-day alternative Hg standard may be used and that electrical output is gross output.

67. Paragraph 7.1.2.6 of Appendix A to subpart UUUUU of Part 63 is added to clarify that EGU owners or operators are to keep records of their EGUs that constitute emissions averaging groups.

68. Paragraphs 2.1, 2.3, 2.3.1, 2.3.2, 3.1, 3.2, 3.3, 5, 5.1, 5.2, and 5.3 of Appendix B to subpart UUUUU of Part 63 are revised to clarify that use of Performance Specification (PS) 18, a proposed technology-neutral PS for HCl CEMS which will soon be promulgated, will be allowed. Consistent with our statements in the final rule, we expect that PS 18 will likely be promulgated in advance of the rule's compliance date. An EGU owner or operator who wishes to use proposed PS 18, along with quality assurance (QA) procedure 6, prior to their promulgation dates is welcome to submit an alternative monitoring request in accordance with the requirements of § 63.8(f) for use of proposed PS 18 and QA Procedure 6 to us.

69. Paragraph 5.4 of Appendix B to subpart UUUUU of Part 63 is added as part of the renumbering due to the addition of PS 18.

70. Paragraph 8 of Appendix B to subpart UUUUU of Part 63 is revised to accommodate use of PS 18.

71. Paragraphs 10.1.8, 10.1.8.1, 10.1.8.1.1, and 10.1.8.1.2 of Appendix B to Subpart UUUUU of Part 63 are revised as part of the renumbering due to the addition of PS 18.

72. Paragraph 10.1.8.1.3 of Appendix B to Subpart UUUUU of Part 63 is revised to clarify that records of relative accuracy audits (RAAs) are also required.

73. Paragraphs 10.1.8.2, 10.1.8.1.2.1, and 10.1.8.1.2.2 of Appendix B to Subpart UUUUU of Part 63 are revised to clarify the quarterly gas audit recordkeeping requirements for PS 15 and the quarterly data accuracy assessments for PS 18 (which are reserved).

74. Paragraph 11.4 of Appendix B to Subpart UUUUU of Part 63 is revised to replace the incorrect abbreviation "*i.e.*" with "*e.g.*"

75. Paragraph 11.4.2 of Appendix B to Subpart UUUUU of Part 63 is revised to specify the requirements of the daily beam intensity checks for EGUs using PS 18.

76. Paragraphs 11.4.2.1, 11.4.2.2, 11.4.2.3, 11.4.2.4, 11.4.2.5, 11.4.2.6, 11.4.2.7, 11.4.2.8, 11.4.2.9, 11.4.2.10, 11.4.2.11, 11.4.2.12, and 11.4.2.13 of Appendix B to Subpart UUUUU of Part 63 are revised to hold the requirements of the daily beam intensity checks for PS 18 (which are reserved).

77. Paragraph 11.4.3 of Appendix B to Subpart UUUUU of Part 63 is revised to reflect the reporting requirements for PS 15.

78. Paragraphs 11.4.3.1, 11.4.3.2, 11.4.3.3, 11.4.3.4, 11.4.3.5, 11.4.3.6, 11.4.3.7, 11.4.3.8, 11.4.3.9, 11.4.3.10, 11.4.3.11, 11.4.3.12, and 11.4.3.13 of Appendix B to Subpart UUUUU of Part 63 are revised to include PS 15 reporting requirements.

79. Paragraph 11.4.4 of Appendix B to Subpart UUUUU of Part 63 is revised to reserve the reporting requirements for quarterly parameter verification checks for PS 18.

80. Paragraphs 11.4.4.1, 11.4.5, 11.4.5.1, 11.4.6, 11.4.6.1 of Appendix B to Subpart UUUUU of Part 63 are added to reserve the reporting requirements for quarterly gas audit information and for quarterly dynamic spiking for PS 18.

81. Paragraph 11.4.7 of Appendix B to Subpart UUUUU of Part 63 is added to include reporting requirements for RAAs.

82. Paragraphs 11.4.7.1, 11.4.7.2, 11.4.7.3, 11.4.7.4, 11.4.7.5, 11.4.7.6, 11.4.7.7, 11.4.7.8, 11.4.7.9, 11.4.7.10, 11.4.7.11, 11.4.7.12, and 11.4.7.13 of Appendix B to Subpart UUUUU of Part 63 are added as part of the renumbering due to the addition of PS 18.

83. Paragraph 11.5.3.4 of Appendix B to Subpart UUUUU of Part 63 is revised to include reporting requirements for beam intensity checks for PS 18.

II. Affirmative Defense for Violation of Emission Standards During Malfunction

In several prior CAA section 112 and CAA section 129 rules, including this rule, the EPA included an affirmative defense to civil penalties for violations caused by malfunctions in an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included the affirmative defense to provide a more formalized approach and more regulatory clarity. *See Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); *but see Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of "upsets beyond the control of the permit holder."). Under the EPA's regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the United States Court of Appeals for the District of Columbia Circuit vacated an affirmative defense in one of the EPA's CAA section 112 regulations. *NRDC* v. *EPA,* 749 F.3d 1055 (D.C. Cir., 2014) (vacating affirmative defense provisions in CAA section 112 rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the court found: "As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.'" *See NRDC,* 749 F.3d at 1063 ("[U]nder this statute, deciding whether penalties are 'appropriate' . . . is a job for the courts, not EPA.").

In light of *NRDC,* the EPA is proposing to remove the regulatory affirmative defense provision in the current rule. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate. Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. *NRDC,* at 1064 (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.

III. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was, therefore, not subject to review by the Office of Management and Budget (OMB).

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden. This action clarifies but does not change the information collection requirements previously finalized and, as a result, does not impose any additional burden on industry. The OMB has previously approved the information collection requirements contained in the existing regulations (see 77 FR 9303, February 16, 2012) under the provisions of the PRA, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0567. The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities. The EPA has determined that none of the small entities will experience a significant impact because the action imposes no additional regulatory requirements on owners or operators of affected sources.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate as described in 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. This action does not significantly or uniquely affect the communities of tribal governments. Thus, Executive Order 13175, does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The corrections do not involve special consideration of environmental justice-related issues as required by Executive Order 12898, and an evaluation was not necessary for this action.

The EPA's compliance with the above statutes and Executive Orders for the underlying rule is discussed in the February 16, 2012, **Federal Register** document containing "National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-

Institutional Steam Generating Units." (77 FR 9303).

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: December 19, 2014.

Gina McCarthy,

Administrator.

For the reasons discussed in the preamble, the EPA proposes to correct and amend 40 CFR parts 60 and 63 to read as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. Section 60.48Da is amended by revising paragraph (f) to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction or reconstruction commenced after May 3, 2011 that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in § 60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup and shutdown.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 3. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 4. Section 63.9983 is amended by:

■ a. Revising the section heading and paragraphs (a), (b), and (c); and

■ Adding paragraph (e).

The revisions and addition read as follows:

§ 63.9983 Are any fossil fuel-fired electric generating units not subject to this subpart?

* * * * *

(a) Any unit designated as a major source stationary combustion turbine subject to 40 CFR part 63, subpart YYYY and any unit designated as an area source stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in § 63.10042.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in § 63.10042. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

* * * * *

(e) Any electric utility steam generating unit that meets the definition of a natural gas-fired EGU under this subpart and that fires at least 10 percent biomass is an industrial boiler subject to standards established under 40 CFR part 63, subpart DDDDD, if it otherwise meets the applicability provisions in that rule.

■ 5. Section 63.9991 is amended by revising paragraphs (c)(1) and (2) to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

* * * * *

(c) * * *

(1) Has a system using wet or dry flue gas desulfurization technology and an SO_2 continuous emissions monitoring system (CEMS) installed on the EGU; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology and the SO_2 CEMS installed on the EGU consistent with § 63.10000(b).

■ 6. Section 63.10000 is amended by:

■ a. Revising paragraph (c)(1)(i);

■ b. Revising paragraph (c)(2)(iii); and

■ c. Adding paragraph (m).

The revisions and additions read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

* * * * *

(c)(1) * * *

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except:

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack exhaust configuration that allows the EGU to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) Notwithstanding paragraph (c)(1)(i)(A) of this section, you may pursue the LEE option provided:

(*1*) Your control device bypass stack is routed through the EGU main stack so that emissions are measured during the bypass event; or

(*2*) You bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent practicable during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

* * * * *

(2) * * *

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance through quarterly performance testing and parametric monitoring for HCl and HF. If you choose to use quarterly testing and parametric monitoring, then you must also develop a site-specific monitoring plan that identifies the CMS you will use to ensure that the operations of the EGU remains consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

* * * * *

(m) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e).

(1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

§ 63.10001 [Removed and reserved]

■ 7. Section 63.10001 is removed and reserved.

■ 8. Section 63.10005 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(2) introductory text and (a)(2)(i);

■ b. Revising paragraph (b)(1);

■ c. Adding paragraph (b)(6);

■ d. Revising paragraphs (d)(3), (d)(4)(i);

■ f. Revising paragraph (f);

■ g. Revising paragraph (h) introductory text, and (h)(3) introductory text;

■ h. Removing paragraphs (i)(4)(iii) and (iv).

The revisions and additions read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (*e.g.,* a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, *e.g.,* hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in § 63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs.

(1) * * *

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.,* an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test may occur on or before the first averaging period (30- or, for certain coal-fired existing EGUs that use emissions averaging for Hg, 90-boiler operating days) after the date that compliance with this subpart is required but must occur such that the averaging period is completed on or before the date that compliance must be demonstrated.

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

* * * * *

(b) * * *

(1) For a performance test of an existing EGU based on stack test data, the test was conducted between 180 and 365 calendar days prior to the date that compliance must be demonstrated as specified in § 63.9984.

* * * * *

(6) If the performance test data that are collected prior to the date that compliance must be demonstrated are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated.

* * * * *

(d) * * *

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30- (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) * * *

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

* * * * *

(f) For an existing EGU without a neural network, a tune-up must occur on or before 180 days after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur on or before 180 days after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the operating conditions remain the same and that the tune-up met all rule requirements.

* * * * *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

* * * * *

(3) For Hg, you must conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A–8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within 10 percent of the duct area centered about the duct's

centroid at a location that meets Method 1 in appendix A–1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12 B in appendix B to part 60 of this chapter.

* * * * *

■ 9. Section 63.10006 is amended by revising paragraph (f) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

* * * * *

(f) *Time between performance tests.* (1) Notwithstanding the provisions of § 63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows:

(i) At least 45 calendar days must separate performance tests conducted every quarter;

(ii) At least 370 calendar days must separate performance tests conducted every year; and

(iii) At least 1,050 calendar days must separate performance tests conducted every 3 years.

(2) Although you are not required to operate your EGU solely in order to conduct a performance test, you must conduct a performance test in the 4th quarter of a calendar year if your EGU has skipped performance tests in the 3 quarters of the calendar year.

(3) If your EGU misses a performance test deadline due to being inoperative and if you have at least 168 boiler operating hours in the next test period, you must complete an additional performance test in that period as follows:

(i) At least 15 calendar days must separate two performance tests conducted in the same quarter.

(ii) At least 107 calendar days must separate two performance tests conducted in the same calendar year.

(iii) At least 350 calendar days must separate two performance tests conducted in the same 3 year period.

* * * * *

■ 10. Section 63.10009 is amended by:

■ a. Revising paragraphs (a)(2) introductory text and (a)(2)(i);

■ b. Revising paragraphs (b)(1) through (3);

■ c. Revising paragraphs (f) introductory text and paragraph (f)(2);

■ d. Revising paragraphs (g)(1) and (2); and

■ e. Revising paragraph (j)(1)(ii).

The revisions read as follows:

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) * * *

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E–2 lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E–2 lb/GWh) from EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory is 90-boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant).

* * * * *

(b) * * *

(1) *Group eligibility equations.*

$$WAER_m = \frac{\sum_{j=1}^{p}\left[\left(\sum_{i=1}^{n} Herm_{i,j}\right) \times Rmm_j \times q_j\right] + \sum_{k=1}^{m} Ter_k \times Rmt_k \times r_k}{\left(\sum_{j=1}^{p} Rmm_j \times q_j\right) + \left(\sum_{k=1}^{m} Rmt_k \times r_k\right)} \quad (Eq.\ 1a)$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = hourly emission rate (*e.g.*, lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = hours in an averaging period (*e.g.*, 720 for a 30-group boiler operating day averaging period or 2160 for a 90-group boiler operating day averaging period),

q_j = hours in an averaging period for EGU j (*e.g.*, 720 for a 30-group boiler operating day averaging period or 2160 for a 90-group boiler operating day averaging period),

Ter_k = Emissions rate (lb/MMBTU or lb/MWh) from the most recent test of EGU k,

Rmt_k = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k,

r_k = hours in an averaging period for EGU k (*e.g.*, 720 for a 30-group boiler operating day averaging period or 2160 for a 90-group boiler operating day averaging period), and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum_{j=1}^{p}\left[\left(\sum_{i=1}^{n} Herm_{i,j}\right) \times Smm_j \times Cfm_j \times q_j\right] + \sum_{k=1}^{m} Ter_k \times Smt_k \times Cft_k \times r_k}{\sum_{j=1}^{p}\left[\sum_{i=1}^{n} Smm_j \times Cfm_j \times q_j\right] + \sum_{k=1}^{m} Smt_k \times Cft_k \times r_k} \quad (Eq.\ 1b)$$

Where:

Variables with the similar names share the descriptions for Equation 1a,

Smm_j = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = conversion factor, calculated from the most recent compliance test results, in terms units of heat input or electrical output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = conversion factor, calculated from the most recent compliance test results, in terms units of heat input or electrical output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.2a)$$

Where:

Her_i = hourly emission rate (*e.g.*, lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hours that hourly rates are collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.3b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

* * * * *

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum possible heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before the date on which you plan to being using emissions averaging. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

* * * * *

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

* * * * *

(g) * * *

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

* * * * *

(j) * * *

(1) * * *

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group;

* * * * *

■ 11. Section 63.10010 is amended by:

■ a. Revising paragraph (a)(4);

■ b. Revising paragraph (f)(3);

■ c. Revising paragraphs (h)(6)(i) and (ii);

■ d. Revising paragraphs (i)(5)(i)(A) and (B);

■ e. Revising paragraph (j)(1)(i) and (j)(4)(i)(A) and (B); and

■ f. Revising paragraph (l).

The revisions read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

* * * * *

(a) * * *

(4) *Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall:

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured, or

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements.

* * * * *

(f) * * *

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the preceding 30 boiler operating days.

* * * * *

(h) * * *

(6) * * *

(i) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions. You must report any such periods in your annual deviation report;

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report.

* * * * *

(i) * * *

(5) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions. You must report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report.

* * * * *

(j) * * *

(1) * * *

(i) Install, calibrate, operate, and maintain your HAP metals CEMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

* * * * *

(4) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions. You must report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report.

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e).

(1) You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

(2) You shall submit the site-specific monitoring plan upon request by the Administrator.

(3) The provisions of the monitoring plan must address the following items:

(i) Monitoring system installation;

(ii) Performance and equipment specifications;

(iii) Schedule for initial and periodic performance evaluations;

(iv) Performance evaluation procedures and acceptance criteria;

(v) On-going operation and maintenance procedures; and

(vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer's specifications to address paragraphs (l)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.

■ 12. Section 63.10011 is amended by revising paragraphs (b), (c), (e) and (g) to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the initial performance test, consisting of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with certified CEMS, expressed in units of the standard, may occur on or before the first averaging period after the date that compliance with the subpart is required but must occur such that the averaging period is completed on or before the date that compliance must be demonstrated. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For an EGU that uses a CEMS to measure SO_2 or PM emission for initial compliance, the initial performance test, consisting of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard, may occur on or before the first averaging period after the date that compliance with the subpart is required but must occur such that the averaging period is completed on or before the date that compliance must be demonstrated. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or PM emission limit in Table 1 or 2 to this subpart.

* * * * *

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, in accordance with § 63.10030(e).

* * * * *

(g) You must follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default electrical load values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in § 63.10031.

(4) If you choose to use paragraph (2) of the definition of "startup" in § 63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of "startup" in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

(i) As mentioned in § 63.6(g)(1), the request will be published in the **Federal Register** for notice and comment rulemaking. Until promulgation in the **Federal Register** of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of "startup" in § 63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the **Federal Register** of the final alternative non-opacity emission standard.

(ii) The request need not address the items contained in § 63.6(g)(2).

(iii) The request shall provide evidence of a documented manufacturer-identified safety issue.

(iv) The request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, the request shall contain documentation that:

(A) The EGU is using clean fuels to the maximum extent practicable, taking into account considerations such as not compromising boiler or control device integrity, to bring the EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in the EGU;

(B) The EGU has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(vi) The request shall specify the other work practice standards the EGU owner or operator will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

■ 13. Section 63.10020 is amended by revising paragraph (e) to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU.

(1) During each period of startup, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of startup begins;

(ii) The quantity and heat input of clean fuel for each hour of startup;

(iii) The gross output for each hour of startup;

(iv) The date and time that non-clean fuel combustion begins; and

(v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins;

(ii) The quantity and heat input of clean fuel for each hour of shutdown;

(iii) The gross output for each hour of shutdown;

(iv) The date and time that non-clean fuel combustion ends; and

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the differential pressure across the scrubber of the liquid during each hour of startup.

■ 14. Section 63.10021 is amended by revising paragraphs (d)(3), (e) introductory text, and (e)(9)(i) and (ii) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(d) * * *

(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may delay the burner inspection until the next scheduled EGU outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

* * * * *

(9) * * *

(i) If the first tune-up is performed prior to April 16, 2015, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is performed on or after April 16, 2015, report the date of the tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

* * * * *

■ 15. Section 63.10023 is amended by removing and reserving paragraph (b)(1) and revising (b)(2) introductory text to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

* * * * *

(b) * * *

(2) Determine your operating limit as follows:

* * * * *

■ 16. Section 63.10030 is amended by:

■ a. Revising paragraphs (e)(1) and (e)(7)(i);

■ b. Adding paragraph (e)(7)(iii);

■ c. Revising paragraph (e)(8);

■ d. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

* * * * *

(7) * * *

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

* * * * *

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply.

(A) You may switch between mass per heat input and mass per gross output levels, provided:

(*1*) You submit a Notification of Compliance Status that identifies for each EGU or EGU emissions averaging group involved in proposed switch both the current and proposed emission limit;

(*2*) Your submission arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(*3*) Your submission demonstrates through performance stack test results conducted within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per electric output limits;

(*4*) You revise and submit all other applicable plans, *e.g.,* monitoring and emissions averaging, with your submission; and

(*5*) You maintain records of all information regarding your choice of emission limits.

(B) You may begin to use the revised emission limits the semi-annual reporting period after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission until the semi-annual reporting period after receipt of written acknowledgement from the Administrator of the switch, you must demonstrate compliance with both the mass per heat input and mass per electric output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of "startup" in § 63.10042.

(i) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(M) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(f) You must submit the notifications in § 63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.

■ 17. Section 63.10031 is amended by:

■ a. Revising paragraphs (c)(4) and (5);

■ b. Adding paragraph (c)(6); and

■ c. Revising paragraph (f)(5).

The revisions and addition read as follows:

§ 63.10031 What reports must I submit and when?

* * * * *

(c) * * *

(4) Include the date of the most recent tune-up for each EGU. For the first tune-up, include the date of the burner inspection if it was delayed.

(5) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, for each instance of startup or shutdown you shall:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of § 63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of § 63.10020(e).

(iii) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO_2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(6) Emergency bypass reports from EGUs with LEE status.

* * * * *

(f) * * *

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1) through (4) of this section in paper format.

* * * * *

■ 18. Section 63.10032 is amended by revising paragraph (f) to read as follows:

§ 63.10032 What records must I keep?

* * * * *

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of "startup" in § 63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

(2) Should you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU, you must keep records of:

(i) The determination of the maximum clean fuel capacity for each EGU;

(ii) The determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and

(iii) The information required in § 63.10020(e).

* * * * *

■ 19. Section 63.10042 is amended by:

■ a. Revising the definitions of "Coal-fired electric utility steam generating unit," "Coal refuse," "Fossil fuel-fired," "Integrated gasification combined cycle electric utility steam generating unit or IGCC," "Limited-use liquid oil-fired subcategory," and "Natural gas-fired electric utility steam generating unit";

■ b. Adding, in alphabetical order, a definition of "Neural network or neural net"; and

■ c. Revising the definition of "Oil-fired electric utility steam generating unit."

The revisions and additions read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

* * * * *

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

* * * * *

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

* * * * *

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

* * * * *

Neural network or *neural net* for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

* * * * *

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years.

* * * * *

■ 20. Revise Table 1 to subpart UUUUU of part 63 to read as follows:

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR Total non-Hg HAP metals	OR 6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E–2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[4] 9.0E–2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2) [3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR Individual HAP metals:	OR Collect a minimum of 2 dscm per run.	
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	3.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.
[4] Duct burners on syngas; gross output.
[5] Duct burners on natural gas; gross output.

■ 21. Revise Table 2 to subpart UUUUU of part 63 to read as follows:

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh	LEE Testing for 90 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
			For ASTM D6348–03[3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 7.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–2 lb/TBtu or 5.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2) [4]	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
[2] Gross output.
[3] Incorporated by reference, see § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 22. Revise Table 3 to subpart UUUUU of part 63 to read as follows:

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS

[As stated in § 63.9991, you must comply with the following applicable work practice standards:]

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU.	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	You have the option of complying using either of the following work practice standards: (1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). (2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent practicable, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits within 4 hours of start of electricity generation. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel. You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices.

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

[As stated in § 63.9991, you must comply with the following applicable work practice standards:]

If your EGU is . . .	You must meet the following . . .
	Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent practicable. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.

■ 23. Revise Table 4 to subpart UUUUU of part 63 to read as follows:

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUS

[As stated in § 63.9991, you must comply with the applicable operating limits:]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 24. Revise Table 5 to subpart UUUUU of part 63 to read as follows:

Table 5 to Subpart UUUUU of Part 63 – Performance Testing Requirements

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]

To conduct a performance test for the following pollutant ...	Using...	You must perform the following activities, as applicable to your input- or output-based emission limit ...	Using ...[2]
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-2 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the filterable PM concentration.	Method 5 at Appendix A-3 to Part 60 of this chapter. When using Method 5, use the average of the final 2 filter weightings.
			For positive pressure fabric filters, Method 5D at Appendix A-3 to Part 60 of this chapter for filterable PM emissions.
			Note that the Method 5 front half temperature shall be 160° ± 14°C (320° ± 25°F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at Appendix B to Part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas,	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

		flow rate, and/or moisture monitoring systems.	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-2 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at Appendix A-8 to Part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A-8 to Part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

		rates.	
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-2 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations.	Method 26 or Method 26A at Appendix A-8 to Part 60 of this chapter or Method 320 at Appendix A to Part 63 of this chapter or ASTM 6348-03[3] with (1) the following conditions using ASTM D6348-03: (A) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; (B) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent

			(%) R must be determined for each target analyte (see Equation A5.5); (C) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70 % ≥ R ≤ 130%; and (D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: $Reported\ Result = \frac{(Measured\ Concentration\ in\ Stack)}{\%R} x\,100$ and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS.	Appendix B of this subpart.
		b. Install, certify,	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

		operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide	Method 3A or 3B at Appendix A-1 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		concentrations of the stack gas.	
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the Hg emission concentration.	Method 30B at Appendix A-8 to Part 60 of this chapter, ASTM D6784[3], or Method 29 at Appendix A-8 to Part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS.	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas,	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

		flow rate, and/or moisture monitoring systems.	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A-1 to Part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A-1 or A-2 to Part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-1 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter, or moisture monitoring systems certified according to Part 75 of this chapter.

		e. Measure the Hg emission concentration.	Method 30B at Appendix A-8 to Part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (i.e., per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold.	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS.	Part 75 of this chapter and §§ 63.10010 (a) and (f).
		b. Install, operate, and maintain the	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

		diluent gas, flow rate, and/or moisture monitoring systems.	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).
[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.
[3] Incorporated by reference, see § 63.14.

■ 25. Revise Table 6 to subpart UUUUU of part 63 to read as follows:

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 26. Revise Table 8 to subpart UUUUU of part 63 to read as follows:

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements for reports:]

You must submit a	The report must contain . . .	You must submit the report . . .
1. Compliance report.	a. Information required in § 63.10031(c)(1) through (6); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e).	Semiannually according to the requirements in § 63.10031(b).

■ 27. Revise Table 9 to subpart UUUUU of part 63 to read as follows:

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:]

Citation	Subject	Applies to subpart UUUUU
§ 63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(g)	Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard.	Yes. See §§ 63.10011(g)(4) and 63.10021(h)(4) for additional requirements.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, except for the 60-day notification prior to conducting a performance test in § 63.9(d); instead use a 30-day notification period per § 63.10030(d).
§ 63.10(a), (b)(1), (c), (d)(1) and—(2), (e), and (f).	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) through—(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3),and (d)(3) through—(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See § 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§§ 63.13 through—63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§§ 63.1(a)(5),(a)(7) through—(9), (b)(2), (c)(3) and—(4), (d), 63.6(b)(6), (c)(3) and), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2) through—(4), (c)(9).	Reserved	No.

■ 28. Appendix A to subpart UUUUU of part 63 is amended by:

■ a. Revising paragraph 3.2.1.2.1;

■ b. Revising paragraphs 4.1.1.1, 4.1.1.3, 4.1.1.5, and 4.1.1.5.2;

■ c. Revising Tables A–1 and A–2;

■ d. Revising paragraphs 5.1.2.1, 5.1.2.3, and 5.2.1; and

■ e. Adding paragraph 6.2.2.3 and 7.1.2.6.

The revisions and additions to read as follows:

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

* * * * *

3. Mercury Emissions Measurement Methods

* * * * *

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.*, NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

* * * * *

4. Certification and Recertification Requirements

* * * * *

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Use a NIST-traceable elemental Hg gas standard (as defined in section 3.1.4 of this appendix) for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over non-consecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.*, resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1 of this appendix. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1 of this appendix. The SIE must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A–8 to part 60 of this chapter. When Method 29 or ASTM D6784–02 is used, paired sampling trains are required and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a Method 29 or ASTM D6784–02 test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a + C_b|}{C_a + C_b} \times 100 \quad (Eq.\ A-1)$$

Where:

RD = Relative Deviation between the Hg concentrations of samples "a" and "b" (percent),

C_a = Hg concentration of Hg sample "a" (µg/dscm), and

C_b = Hg concentration of Hg sample "b" (µg/dscm).

* * * * *

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2) including the option to substitute the emission limit value (in this case the equivalent concentration) in the denominator of Equation 2–6 in place of the average RM value when the average emissions for the test are less than 50 percent of the applicable emissions limit. For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS

For this required certification test . . .	The main performance specification [1] is . . .	The alternate performance specification [1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test [2]	$\|R - A\| \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$\|R - A\| \leq 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check [3]	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$\|R - A_{avg}\| \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check [4]	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$\|R - A_{avg}\| \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	≤10% RA when concentration equivalent of applicable emissions limit is used in place of RM_{avg} in Equation 2–6 of PS2 (see Section 4.1.1.5.2 of this appendix).	RM_{avg} <50% of applicable emissions limit.

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS—Continued

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
Cycle time test[2]	15 minutes where the stability criteria are readings change by <2.0% of span *or* by ≤0.5 μg/scm, for 2 minutes.		

[1] Note that \|R − A\| is the absolute value of the difference between the reference gas value and the analyzer reading. $|R - A_{avg}|$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.
[2] Use elemental Hg standards; a mid-level or high-level upscale gas may be used. The cycle time test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.
[3] Use elemental Hg standards.
[4] Use oxidized Hg standards.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high-level gas. • Use elemental Hg • Calibrations are not required when the unit is not in operation.	|R − A| ≤5.0% of span value *or* |R − A| ≤1.0 μg/scm.
Single-level system integrity check	Weekly[1]	• Use oxidized Hg—either mid- or high-level.	$|Rn - A_{avg}|$ ≤10.0% of the reference gas value *or* $|R - A_{avg}|$ ≤0.8 μg/scm.
Linearity check *or* 3-level system integrity check.	Quarterly[3]	• Required in each "QA operating quarter"[2] and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check.	$|R - A_{avg}|$ ≤10.0% of the reference gas value, at each calibration gas level *or* $|R - A_{avg}|$ ≤0.8 μg/scm.
RATA	Annual[4]	• Test deadline may be extended for "non-QA operating quarters," up to a maximum of 8 quarters from the quarter of the previous test. • 720 operating hour grace period available.	≤20.0% RA when C_{avg} ≥50% of the emissions limit *or* ≤10.0% RA when C_{avg} <50% of the emissions limit and the concentration equivalent of the applicable emission limit is used in the denominator of Equation 2–6 of PS2 (see Section 4.1.1.5.1 of this appendix).

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.

* * * * *

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable elemental Hg gas standard for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

* * * * *

5.1.2.3 Perform a single-level system integrity check weekly, *i.e.*, once every 7 operating days (see the third column in Table A–2 of this appendix).

* * * * *

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

* * * * *

6. Data Reductions and Calculations

* * * * *

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation A–5 of this appendix to calculate the Hg emission rate for each averaging period.

$$\bar{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \quad (Eq.\ A-5)$$

Where:

E_o = Hg emission rate for the averaging period (lb/GWh),

E_{ho} = Gross output-based hourly Hg emission rate for unit or stack sampling hour "h" in the averaging period, from Equation A–4 of this appendix (lb/GWh), and

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters.

(*Note:* Do *not* include non-operating hours with zero emission rates in the average).

* * * * *

7. Recordkeeping and Reporting

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7.1.2.6 The EGUs that constitute an emissions averaging group.

* * * * *

■ 29. Appendix B to subpart UUUUU of part 63 is amended by:

■ a. Revising paragraph 2.1 and 2.3;

■ b. Adding paragraphs 2.3.1 and 2.3.2;

■ c. Revising paragraphs 3.1 and 3.2 and adding paragraph 3.3;

■ d. Adding introductory text to section 5. On-Going Quality Assurance Requirements;

■ e. Revising paragraphs 5.1, 5.2, and 5.3;

■ f. Adding paragraphs 5.4, 5.4.1, 5.4.2, 5.4.2.1, 5.4.2.2, 5.4.2.2.1, 5.4.2.2.2, 5.4.2.3, 5.4.2.3.1, 5.4.2.3.2, 5.4.2.3.3, and 5.4.3;

■ g. Revising section 8. introductory text;

■ h. Revising paragraphs 10.1.8, 10.1.8.1, 10.1.8.1.1, and 10.1.8.1.2, adding paragraph 10.1.8.1.2.1, and adding and reserving paragraph 10.1.8.1.2.2;

■ i. Revising paragraph 10.1.8.1.3;

■ j. Revising paragraphs 11.4 and 11.4.2 and removing and reserving paragraphs 11.4.2.1 through 11.4.2.13;

■ k. Revising paragraphs 11.4.3 and 11.4.3.1 through 11.4.3.13;

■ l. Revising paragraph 11.4.4 and adding and reserving paragraph 11.4.4.1;

■ m. Adding paragraph 11.4.5 and adding and reserving paragraph 11.4.5.1;

■ n. Adding paragraph 11.4.6 and adding and reserving paragraph 11.4.6.1;

■ o. Adding paragraphs 11.4.7, 11.4.7.1 through 11.4.7.13;

■ p. Revising paragraph 11.4.8 and

■ q. Revising paragraph 11.5.3.4.

■ The revisions and additions read as follows:

Appendix B to Subpart UUUUU of Part 63—HC_L and HF Monitoring Provisions

* * * * *

2. Monitoring of HC_L and/or HF Emissions

* * * * *

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems and § 63.10010(a) or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS and § 63.10010(a).

* * * * *

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter, or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

* * * * *

3.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

* * * * *

3.2 If you choose to follow Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

* * * * *

5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

* * * * *

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of Procedure 6 of 40 CFR part 60, appendix F shall apply.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

* * * * *

5.4 *Data Validation.*

5.4.1 *Out-of-Control Periods.* An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 *Grace Periods.* For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit/data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems required under in section 5.3 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit/data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in § 75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

* * * * *

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in paragraph 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

* * * * *

10. Recordkeeping Requirements

* * * * *

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations and checks (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values and their certification information, action levels for integrated path HCl CEMS, HCl or HF monitor responses, and calculated calibration error values;

10.1.8.1.2 For quarterly gas audits of HCl or HF CEMS certified under PS 15 of appendix B to part 60 of this chapter follow paragraph 10.1.8.1.2.1 of this appendix and for quarterly data accuracy assessments under PS 18 of appendix B to part 60 of this chapter follow paragraph 10.1.8.1.2.2 of this appendix.

10.1.8.1.2.1 Record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of P S 15 of appendix B to part 60 of this chapter, and the results of those calculations and analyses.

10.1.8.1.2.2 [Reserved]

10.1.8.1.3 For each RATA or RAA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

* * * * *

11. Reporting Requirements

* * * * *

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*e.g.,* calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

* * * * *

11.4.2 For daily beam intensity checks for integrated path HCl CEMS as specified by PS 18 of appendix B to part 60 of this chapter, report:

11.4.2.1 through 11.4.2.13 [Reserved]

11.4.3 For each quarterly gas audit of an HCl or HF CEMS under Performance Specification 15, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (*e.g.,* quarterly gas audit);

11.4.3.4 Reason for test;

11.4.3.5 Certified audit (spike) gas concentration value (ppm);

11.4.3.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.3.7 Calculated dilution ratio for audit (spike) gas;

11.4.3.8 Date and time of each spiked flue gas sample;

11.4.3.9 Date and time of each unspiked flue gas sample;

11.4.3.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.3.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of PS 15 of appendix B to part 60 of this chapter (ppm);

11.4.3.12 Bias at the spike level as calculated using equation 3 in section 12.1 of PS 15 of appendix B to part 60 of this chapter; and

11.4.3.13 The correction factor (CF), calculated using equation 6 in section 12.1 of PS 15 of appendix B to part 60 of this chapter.

11.4.4 For each quarterly parameter verification check for an integrated path HCl CEMS under PS 18 of appendix B to part 60 of this chapter, report:

11.4.4.1 [Reserved]

11.4.5 For each quarterly gas audit under P S 18 of appendix B to part 60 of this chapter, report:

11.4.5.1 [Reserved]

11.4.6 For each quarterly dynamic spiking audit as allowed by P S 18 of appendix B to part 60 of this chapter, report:

11.4.6.1 [Reserved]

11.4.7 For each RATA or RAA of an HCl or HF CEMS, report:

11.4.7.1 Facility ID information;

11.4.7.2 Monitoring system ID number;

11.4.7.3 Type of test (*i.e.,* initial or annual RATA or RAA);

11.4.7.4 Reason for test;

11.4.7.5 The reference method used;

11.4.7.6 Starting and ending date and time for each test run;

11.4.7.7 Units of measure;

11.4.7.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.7.9 Flags to indicate which test runs were used in the calculations;

11.4.7.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.7.11 Standard deviation, as specified in Equation 2–4 of PS 2 or PS 18, as applicable in appendix B to part 60 of this chapter;

11.4.7.12 Confidence coefficient, as specified in Equation 2–5 of PS 2 or PS 18, as applicable in appendix B to part 60 of this chapter; and

11.4.7.13 Relative accuracy calculated using Equation 2–6 of PS 2 or PS 18, as applicable in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in paragraph 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

* * * * *

11.4.8 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.8.2 of this appendix.

* * * * *

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests and beam intensity checks of integrated path CEMS) of the HCl or HF monitor as described in paragraph 10.1.8.1.1 of this appendix; and

* * * * *

[FR Doc. 2015–01699 Filed 2–13–15; 8:45 am]

BILLING CODE 6560–50–P

Andrews, Edward S

From:	Andrews, Edward S
Sent:	Thursday, February 04, 2016 9:00 AM
To:	'tshirley@ppmsllc.com'
Cc:	Patrick E. Ward; Dan Traynor (dtraynor@ppmsllc.com)
Subject:	WV DAQ NSR Permit Application Complete for Morgantown Energy Associates - Morgantown Energy Facility

RE: Application Status: Complete
Morgantown Energy Associates – Morgantown Energy Facility
Permit Application R14-0007C
Plant ID No. 061-00027

Mr. Shirley:

Your application for a modification permit for a fossil fuel fired cogeneration facility was received by this Division on November 23, 2015, and assigned to the writer for review. Upon review of said application, it has been determined that the application is complete and, therefore, the statutory review period commenced on January 27, 2016.

This determination of completeness shall not relieve the permit applicant of the requirement to subsequently submit, in a timely manner, any additional or corrected information deemed necessary for a final permit determination.

Should you have any questions, please contact Ed Andrews at (304) 926-0499 ext. 1214 or reply to this email.

Sincerely,

Edward S. Andrews, P.E.
Engineer
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
304.926.0499 ext. 1214

Entire Document
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2011 Emissions Report

Total Emissions by Emission Unit for MORGANTOWN ENERGY ASSOCIATES

002 TRANSFER CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000136
PM10-FIL - PM10 Filterable	0.000136
PM25-FIL - PM2.5 Filterable	6.8E-05

ID # 061-00027
Reg R14-0007C
Company MEA
Facility Morgantown Energy Initials [illegible]

003 ELEVATING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000649
PM10-FIL - PM10 Filterable	0.000649
PM25-FIL - PM2.5 Filterable	0.000325

004 MILL COLLECTING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000649
PM10-FIL - PM10 Filterable	0.000649
PM25-FIL - PM2.5 Filterable	0.000325

005 TWO COAL/GOB CRUSHERS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.321
PM10-FIL - PM10 Filterable	0.321
PM25-FIL - PM2.5 Filterable	0.185

006 LIMESTONE STORAGE SILO

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00312
PM10-FIL - PM10 Filterable	0.00312
PM25-FIL - PM2.5 Filterable	0.00178

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007 LIMESTONE UNLOADING HOPPR

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00601
PM10-FIL - PM10 Filterable	0.00601
PM25-FIL - PM2.5 Filterable	0.00334

008 LIMESTONE DAY BIN

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00111
PM10-FIL - PM10 Filterable	0.00111
PM25-FIL - PM2.5 Filterable	0.000668

009 PNEUMATIC ASH HANDLING

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.0677
PM10-FIL - PM10 Filterable	0.0677
PM25-FIL - PM2.5 Filterable	0.0387

010 MECH SYSTEM BOTTOM ASH

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.114
PM10-FIL - PM10 Filterable	0.114
PM25-FIL - PM2.5 Filterable	0.0651

011 FLYASH TRANSPORT SILO VNT

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.445
PM10-FIL - PM10 Filterable	0.445
PM25-FIL - PM2.5 Filterable	0.256

012 FUEL RECEIVING FUGITIVES

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00941
PM10-FIL - PM10 Filterable	0.00445
PM25-FIL - PM2.5 Filterable	0.000674

013 EMERGENCY FUEL FEED FUG.

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0
PM10-FIL - PM10 Filterable	0
PM25-FIL - PM2.5 Filterable	0

014 STORAGE TANK FUGITIVES

Pollutant	Total Emissions (Tons)
VOC - Volatile Organic Compounds	0

015 FUGUTIVE ROAD DUST

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.0687
PM10-FIL - PM10 Filterable	0.013
PM25-FIL - PM2.5 Filterable	0.00324

043 BOILERS

Pollutant	Total Emissions (Tons)
106467 - 1,4-Dichlorobenzene	4.27E-05
121142 - 2,4-Dinitrotoluene	5.42E-05
532274 - 2-Chloroacetophenone	0.001354
75070 - Acetaldehyde	0.1103
98862 - Acetophenone	0.00291
107028 - Acrolein	0.0561
NH3 - Ammonia	0.109278
7440360 - Antimony	0.00483
7440382 - Arsenic	0.00214712
71432 - Benzene	0.2510747
100447 - Benzyl Chloride	0.1354
7440417 - Beryllium	6.0727E-05
117817 - Bis(2-Ethylhexyl)Phthalate	0.01412
75252 - Bromoform	0.00754
7440439 - Cadmium	0.00048392
75150 - Carbon Disulfide	0.0251
CO - Carbon Monoxide	195.98
108907 - Chlorobenzene	0.00426
67663 - Chloroform	0.01141
7440473 - Chromium	0.00409498

7440484 - Cobalt	0.00064698
98828 - Cumene	0.001025
57125 - Cyanide	0.483
78933 - DELETED - Methyl Ethyl Ketone	0.0754
77781 - Dimethyl Sulfate	0.00928
100414 - Ethyl Benzene	0.01818
75003 - Ethyl Chloride	0.00812
106934 - Ethylene Dibromide	0.000232
107062 - Ethylene Dichloride	0.00774
50000 - Formaldehyde	0.049067
110543 - Hexane	0.076965
7647010 - Hydrochloric Acid	23.52
7664393 - Hydrogen Fluoride	0.1694
78591 - Isophorone	0.1122
7439921 - Lead	0.00772779
7439965 - Manganese	0.00890351
7439976 - Mercury	0.00277925
74839 - Methyl Bromide	0.0309
74873 - Methyl Chloride	0.1025
71556 - Methyl Chloroform	0.00386
80626 - Methyl Methacrylate	0.00386
1634044 - Methyl Tert-Butyl Ether	0.00677
75092 - Methylene Chloride	0.0561
60344 - Methylhydrazine	0.0329
91203 - Naphthalene	2.17E-05
7440020 - Nickel	0.0024047
NOX - Nitrogen Oxides	818.680102
PM-CON - PM Condensible	65.57309
PM-FIL - PM Filterable	40.28959
PM10-FIL - PM10 Filterable	40.28959
PM25-FIL - PM2.5 Filterable	40.28959
108952 - Phenol	0.00309
123386 - Propionaldehyde	0.0735
246 - REPLACE WITH 250 - Polycyclic Organic Matter	3.06E-08
605 - Radionuclides (Including Radon)	0.0037
7782492 - Selenium	0.001505854
100425 - Styrene	0.00483
SO2 - Sulfur Dioxide	1024.12
127184 - Tetrachloroethylene	0.00832
108883 - Toluene	0.0465209

108054 - Vinyl Acetate	0.00147
VOC - Volatile Organic Compounds	3.74
1330207 - Xylenes (Mixed Isomers)	0.00715

2012 Emissions Report

Total Emissions by Emission Unit for MORGANTOWN ENERGY FACILITY

002 TRANSFER CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00039
PM10-FIL - PM10 Filterable	0.000139
PM25-FIL - PM2.5 Filterable	6.96E-05

003 ELEVATING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000665
PM10-FIL - PM10 Filterable	0.000665
PM25-FIL - PM2.5 Filterable	0.000333

004 MILL COLLECTING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000665
PM10-FIL - PM10 Filterable	0.000665
PM25-FIL - PM2.5 Filterable	0.000333

005 TWO COAL/GOB CRUSHERS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.329
PM10-FIL - PM10 Filterable	0.329
PM25-FIL - PM2.5 Filterable	0.19

006 LIMESTONE STORAGE SILO

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00342
PM10-FIL - PM10 Filterable	0.00342
PM25-FIL - PM2.5 Filterable	0.00196

007 LIMESTONE UNLOADING HOPPR

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.0066
PM10-FIL - PM10 Filterable	0.0066
PM25-FIL - PM2.5 Filterable	0.00367

008 LIMESTONE DAY BIN

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00122
PM10-FIL - PM10 Filterable	0.00122
PM25-FIL - PM2.5 Filterable	0.00734

009 PNEUMATIC ASH HANDLING

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.0711
PM10-FIL - PM10 Filterable	0.0711
PM25-FIL - PM2.5 Filterable	0.0406

010 MECH SYSTEM BOTTOM ASH

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.177
PM10-FIL - PM10 Filterable	0.117
PM25-FIL - PM2.5 Filterable	0.0668

011 FLYASH TRANSPORT SILO VNT

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.467
PM10-FIL - PM10 Filterable	0.467
PM25-FIL - PM2.5 Filterable	0.269

012 FUEL RECEIVING FUGITIVES

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00965
PM10-FIL - PM10 Filterable	0.00456
PM25-FIL - PM2.5 Filterable	0.000691

013 EMERGENCY FUEL FEED FUG.

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0
PM10-FIL - PM10 Filterable	0
PM25-FIL - PM2.5 Filterable	0

014 STORAGE TANK FUGITIVES

Pollutant	Total Emissions (Tons)
VOC - Volatile Organic Compounds	0

015 FUGUTIVE ROAD DUST

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.071
PM10-FIL - PM10 Filterable	0.0134
PM25-FIL - PM2.5 Filterable	0.00335

043 BOILERS

Pollutant	Total Emissions (Tons)
106467 - 1,4-Dichlorobenzene	5.076E-05
121142 - 2,4-Dinitrotoluene	5.55E-05
532274 - 2-Chloroacetophenone	0.001389
75070 - Acetaldehyde	0.1131
98862 - Acetophenone	0.00298
107028 - Acrolein	0.0575
NH3 - Ammonia	0.1121211425
7440360 - Antimony	0.00509
7440382 - Arsenic	0.00226846
71432 - Benzene	0.25808883
100447 - Benzyl Chloride	0.1389
7440417 - Beryllium	6.40076E-05
117817 - Bis(2-Ethylhexyl)Phthalate	0.01448
75252 - Bromoform	0.00773
7440439 - Cadmium	0.000510653
75150 - Carbon Disulfide	0.0258
CO - Carbon Monoxide	206.86
108907 - Chlorobenzene	0.00437
67663 - Chloroform	0.01171
7440473 - Chromium	0.004315922

7440484 - Cobalt	0.0006825532
98828 - Cumene	0.001052
57125 - Cyanide	0.496
78933 - DELETED - Methyl Ethyl Ketone	0.0773
77781 - Dimethyl Sulfate	0.00953
100414 - Ethyl Benzene	0.01865
75003 - Ethyl Chloride	0.00833
106934 - Ethylene Dibromide	0.000238
107062 - Ethylene Dichloride	0.00793
50000 - Formaldehyde	0.0507725
110543 - Hexane	0.08944
7647010 - Hydrochloric Acid	24.78
7664393 - Hydrogen Fluoride	0.1786
78591 - Isophorone	0.1151
7439921 - Lead	0.00814115
7439965 - Manganese	0.009386074
7439976 - Mercury	0.002920998
74839 - Methyl Bromide	0.0318
74873 - Methyl Chloride	0.1052
71556 - Methyl Chloroform	0.00397
80626 - Methyl Methacrylate	0.00397
1634044 - Methyl Tert-Butyl Ether	0.00695
75092 - Methylene Chloride	0.0575
60344 - Methylhydrazine	0.0337
91203 - Naphthalene	2.5803E-05
7440020 - Nickel	0.00253883
NOX - Nitrogen Oxides	910.03
PM-CON - PM Condensible	50.92
PM-FIL - PM Filterable	23.84
PM10-FIL - PM10 Filterable	23.84
PM25-FIL - PM2.5 Filterable	17.4
108952 - Phenol	0.00318
123386 - Propionaldehyde	0.0755
246 - REPLACE WITH 250 - Polycyclic Organic Matter	3.6378E-08
605 - Radionuclides (Including Radon)	0.0038
7782492 - Selenium	0.0015870152
100425 - Styrene	0.00496
SO2 - Sulfur Dioxide	908.75
127184 - Tetrachloroethylene	0.00853
108883 - Toluene	0.04774382

108054 - Vinyl Acetate	0.001508
VOC - Volatile Organic Compounds	3.96
1330207 - Xylenes (Mixed Isomers)	0.00735

2013 Emissions Report

Total Emissions by Emission Unit for MORGANTOWN ENERGY FACILITY

002 TRANSFER CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000138
PM10-FIL - PM10 Filterable	0.000138
PM25-FIL - PM2.5 Filterable	6.88E-05

003 ELEVATING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000687
PM10-FIL - PM10 Filterable	0.000687
PM25-FIL - PM2.5 Filterable	0.000344

004 MILL COLLECTING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.000687
PM10-FIL - PM10 Filterable	0.000687
PM25-FIL - PM2.5 Filterable	0.000344

005 TWO COAL/GOB CRUSHERS

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.34
PM10-FIL - PM10 Filterable	0.34
PM25-FIL - PM2.5 Filterable	0.196

006 LIMESTONE STORAGE SILO

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00341
PM10-FIL - PM10 Filterable	0.00341
PM25-FIL - PM2.5 Filterable	0.00195

007 LIMESTONE UNLOADING HOPPR

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00658
PM10-FIL - PM10 Filterable	0.00658
PM25-FIL - PM2.5 Filterable	0.00366

008 LIMESTONE DAY BIN

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00122
PM10-FIL - PM10 Filterable	0.00122
PM25-FIL - PM2.5 Filterable	0.000731

009 PNEUMATIC ASH HANDLING

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.064
PM10-FIL - PM10 Filterable	0.064
PM25-FIL - PM2.5 Filterable	0.0366

010 MECH SYSTEM BOTTOM ASH

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.115
PM10-FIL - PM10 Filterable	0.115
PM25-FIL - PM2.5 Filterable	0.0657

011 FLYASH TRANSPORT SILO VNT

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.421
PM10-FIL - PM10 Filterable	0.421
PM25-FIL - PM2.5 Filterable	0.242

012 FUEL RECEIVING FUGITIVES

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.00953
PM10-FIL - PM10 Filterable	0.00451
PM25-FIL - PM2.5 Filterable	0.000682

015 FUGUTIVE ROAD DUST

Pollutant	Total Emissions (Tons)
PM-FIL - PM Filterable	0.07219925
PM10-FIL - PM10 Filterable	0.0136225
PM25-FIL - PM2.5 Filterable	0.003405625

043 BOILERS

Pollutant	Total Emissions (Tons)
106467 - 1,4-Dichlorobenzene	5.3706E-05
121142 - 2,4-Dinitrotoluene	5.517568E-05
532274 - 2-Chloroacetophenone	0.001379392
75070 - Acetaldehyde	0.11232192
98862 - Acetophenone	0.00295584
107028 - Acrolein	0.05714624
NH3 - Ammonia	0.11133664
7440360 - Antimony	0.0045
7440382 - Arsenic	0.002003951
71432 - Benzene	0.2562667855
100447 - Benzyl Chloride	0.1379392
7440417 - Beryllium	5.663706E-05
117817 - Bis(2-Ethylhexyl)Phthalate	0.014385088
75252 - Bromoform	0.007685184
7440439 - Cadmium	0.0004962305
75150 - Carbon Disulfide	0.02561728
CO - Carbon Monoxide	183.40942
108907 - Chlorobenzene	0.004335232
67663 - Chloroform	0.011626304
7440473 - Chromium	0.003872657
7440484 - Cobalt	0.00060375942
98828 - Cumene	0.0010443968
57125 - Cyanide	0.49264
78933 - DELETED - Methyl Ethyl Ketone	0.07685184
77781 - Dimethyl Sulfate	0.009458688
100414 - Ethyl Benzene	0.018523264
75003 - Ethyl Chloride	0.008276352
106934 - Ethylene Dibromide	0.0002364672
107062 - Ethylene Dichloride	0.00788224
50000 - Formaldehyde	0.050650065
110543 - Hexane	0.093761752
7647010 - Hydrochloric Acid	21.9

7664393 - Hydrogen Fluoride	0.1578
78591 - Isophorone	0.11429248
7439921 - Lead	0.0071823775
7439965 - Manganese	0.0082970069
7439976 - Mercury	0.0025816363
74839 - Methyl Bromide	0.03152896
74873 - Methyl Chloride	0.10443968
71556 - Methyl Chloroform	0.00394112
80626 - Methyl Methacrylate	0.00394112
1634044 - Methyl Tert-Butyl Ether	0.00689696
75092 - Methylene Chloride	0.05714624
60344 - Methylhydrazine	0.03349952
91203 - Naphthalene	2.730055E-05
7440020 - Nickel	0.0022639855
NOX - Nitrogen Oxides	1056.98
250 - PAH/POM - Unspecified	3.8892095E-08
PM-CON - PM Condensible	44.9351035
PM-FIL - PM Filterable	24.0750345
PM10-FIL - PM10 Filterable	24.0750345
PM25-FIL - PM2.5 Filterable	15.3850345
108952 - Phenol	0.003152896
123386 - Propionaldehyde	0.07488128
605 - Radionuclides (Including Radon)	0.00373
7782492 - Selenium	0.00140107412
100425 - Styrene	0.0049264
SO2 - Sulfur Dioxide	913.922959315
127184 - Tetrachloroethylene	0.008473408
108883 - Toluene	0.047445607
108054 - Vinyl Acetate	0.0014976256
VOC - Volatile Organic Compounds	3.5461525
1330207 - Xylenes (Mixed Isomers)	0.007291072

2014 Emissions Report

Total Emissions by Emission Unit for MORGANTOWN ENERGY FACILITY

002 TRANSFER CONVEYORS

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.0001445
PM10-FIL - PM10 Filterable	0.0001445
PM25-FIL - PM2.5 Filterable	7.22E-05

003 ELEVATING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.0007988
PM10-FIL - PM10 Filterable	0.0007988
PM25-FIL - PM2.5 Filterable	0.0003994

004 MILL COLLECTING CONVEYORS

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.0007988
PM10-FIL - PM10 Filterable	0.0007988
PM25-FIL - PM2.5 Filterable	0.0003994

005 TWO COAL/GOB CRUSHERS

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.3954
PM10-FIL - PM10 Filterable	0.3954
PM25-FIL - PM2.5 Filterable	0.2277

006 LIMESTONE STORAGE SILO

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0

PM-FIL - PM Filterable	0.00348
PM10-FIL - PM10 Filterable	0.00348
PM25-FIL - PM2.5 Filterable	0.00199

007 LIMESTONE UNLOADING HOPPER

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.00671
PM10-FIL - PM10 Filterable	0.00671
PM25-FIL - PM2.5 Filterable	0.00373

008 LIMESTONE DAY BIN

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.00124
PM10-FIL - PM10 Filterable	0.00124
PM25-FIL - PM2.5 Filterable	0.000745

009 PNEUMATIC ASH HANDLING

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.0665
PM10-FIL - PM10 Filterable	0.0665
PM25-FIL - PM2.5 Filterable	0.038

010 MECH SYSTEM BOTTOM ASH

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.117
PM10-FIL - PM10 Filterable	0.117
PM25-FIL - PM2.5 Filterable	0.067

011 FLYASH TRANSPORT SILO VNT

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.437
PM10-FIL - PM10 Filterable	0.437

PM25-FIL - PM2.5 Filterable	0.252

012 FUEL RECEIVING FUGITIVES

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.00996
PM10-FIL - PM10 Filterable	0.00471
PM25-FIL - PM2.5 Filterable	0.000714

014 STORAGE TANK FUGITIVES

Pollutant	Total Emissions (Tons)
VOC - Volatile Organic Compounds	0

015 FUGITIVE ROAD DUST

Pollutant	Total Emissions (Tons)
PM-CON - PM Condensible	0
PM-FIL - PM Filterable	0.07495525
PM10-FIL - PM10 Filterable	0.0141425
PM25-FIL - PM2.5 Filterable	0.003535625

043 BOILERS

Pollutant	Total Emissions (Tons)
106467 - 1,4-Dichlorobenzene	3.9588E-05
121142 - 2,4-Dinitrotoluene	5.572238E-05
532274 - 2-Chloroacetophenone	0.0013930595
75070 - Acetaldehyde	0.113434845
98862 - Acetophenone	0.0029851275
107028 - Acrolein	0.057712465
NH3 - Ammonia	0.1124398025
7440360 - Antimony	0.005
7440382 - Arsenic	0.002216598
71432 - Benzene	0.258780329
100447 - Benzyl Chloride	0.13930595
7440417 - Beryllium	6.249794E-05
117817 - Bis(2-Ethylhexyl)Phthalate	0.0145276205
75252 - Bromoform	0.0077613315
7440439 - Cadmium	0.000533289
75150 - Carbon Disulfide	0.025871105

CO - Carbon Monoxide	136.06116
108907 - Chlorobenzene	0.004378187
67663 - Chloroform	0.0117415015
7440473 - Chromium	0.004276186
7440484 - Cobalt	0.00066877116
98828 - Cumene	0.00105474505
57125 - Cyanide	0.49752125
77781 - Dimethyl Sulfate	0.009552408
100414 - Ethyl Benzene	0.018706799
75003 - Ethyl Chloride	0.008358357
106934 - Ethylene Dibromide	0.0002388102
107062 - Ethylene Dichloride	0.00796034
50000 - Formaldehyde	0.05023629
110543 - Hexane	0.0727155695
7647010 - Hydrochloric Acid	24.33
7664393 - Hydrogen Fluoride	0.1753
78591 - Isophorone	0.11542493
7439921 - Lead	0.007976495
7439965 - Manganese	0.0092025362
7439976 - Mercury	0.0028685774
74839 - Methyl Bromide	0.03184136
74873 - Methyl Chloride	0.105474505
71556 - Methyl Chloroform	0.00398017
80626 - Methyl Methacrylate	0.00398017
1634044 - Methyl Tert-Butyl Ether	0.0069652975
75092 - Methylene Chloride	0.057712465
60344 - Methylhydrazine	0.033831445
91203 - Naphthalene	2.01239E-05
7440020 - Nickel	0.002479279
NOX - Nitrogen Oxides	1108.19
250 - PAH/POM - Unspecified	2.3093E-06
PM-CON - PM Condensible	49.848043
PM-FIL - PM Filterable	26.722681
PM10-FIL - PM10 Filterable	26.722681
PM25-FIL - PM2.5 Filterable	17.052681
108952 - Phenol	0.003184136
123386 - Propionaldehyde	0.07562323
605 - Radionuclides (Including Radon)	0.00382
7782492 - Selenium	0.00155639588
100425 - Styrene	0.0049752125
SO2 - Sulfur Dioxide	1027.51692387

127184 - Tetrachloroethylene	0.0085573655
108883 - Toluene	0.047874206
108054 - Vinyl Acetate	0.0015124646
VOC - Volatile Organic Compounds	3.841445
1330207 - Xylenes (Mixed Isomers)	0.0073633145

Morgantown Energy Associates
555 Beechurst Avenue
Morgantown, West Virginia 26505
304.284.2500 PHONE
304.284.2509 FAX

MEA
Morgantown Energy Associates

VIA E-MAIL: Edward.S.Andrews@wv.gov

January 27, 2016

Mr. Edward S. Andrews
Engineer -- Division of Air Quality
West Virginia Department of Environmental Protection
601 57th Street SE
Charleston, WV 25304

RE: Morgantown Energy Associates - Morgantown Energy Facility
Permit Application No. R14-0007C
Plant ID No. 061-00027
Updated SNCR reagent bulk storage system design information

Dear Mr. Andrews:

Morgantown Energy Associates (MEA) would like to make an update to Permit Application No. R14-0007C initially submitted on November 20, 2015. The update is in reference to the SNCR reagent bulk storage system design information

In Attachment G of the modification, it is stated that "Storage of urea or aqueous ammonia is estimated to be less than 1500 gallons." Also, the system diagrams in Attachment F and Appendix 2 refer to "Reagent Storage – Totes".

MEA's updated design for SNCR reagent storage is to store urea or aqueous ammonia in a 9000 gallon double-walled tank made of fiberglass-reinforced plastic. The tank will be 9 feet in diameter and 18 feet in height. MEA will register the tank under the recently passed WV regulations regarding above ground storage tank registration and inspections. Totes will not be used in the current system but could be incorporated as an emergency backup in the event of interruption in supply from the bulk storage tank. The update in the SNCR reagent storage will not adversely impact air emissions at the site.

If you have any questions or comments about the information provided, please do not hesitate to contact Dan Traynor at (610) 390-3522 or Todd Shirley at (704) 815-8022.

Very truly yours,

Todd Shirley

Todd Shirley
Projects General Manager

cc: File

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Andrews, Edward S

From: Todd Shirley <tshirley@ppmsllc.com>
Sent: Tuesday, January 05, 2016 12:55 PM
To: Andrews, Edward S
Subject: RE: WV DAQ Permit Application Incomplete for Morgantown Energy Associates - Morgantown Energy Facility

Ed,

The MEA plant team indicated that you may have a questions regarding the business plan and the reduced generation for one of the years. The reduced MW estimate for the one year compared to the others is related to the extended maintenance associated with the periodic steam turbine and generator inspection. Let me know if you need additional information.

Regards,
Todd Shirley
Projects General Manager
Power Plant Management Services, LLC
10710 Sikes Place, Suite 300
Charlotte, NC 28277
704-815-8022 (Office)
704-909.8158 (Cell)
tshirley@ppmsllc.com

From: Todd Shirley
Sent: Friday, December 18, 2015 4:59 PM
To: 'Andrews, Edward S' <Edward.S.Andrews@wv.gov>
Cc: McKeone, Beverly D <Beverly.D.Mckeone@wv.gov>; josh.manley@nrg.com; Patrick E. Ward <PEWard@potesta.com>; Shimshock, John <John.Shimshock@nrg.com>; Dan Traynor <dtraynor@ppmsllc.com>
Subject: RE: WV DAQ Permit Application Incomplete for Morgantown Energy Associates - Morgantown Energy Facility

Mr. Andrews,

Attached is a pdf of the MEA response to your previous e-mail regarding:

RE: Application Status: Incomplete
Morgantown Energy Associates
Morgantown Energy Facility
Permit Application No. R14-0007C
Plant ID No. 061-00027

An original copy will also be sent to your attention. Please let me know if you have any questions or concerns.

Regards,
Todd Shirley
Projects General Manager
Power Plant Management Services, LLC
10710 Sikes Place, Suite 300
Charlotte, NC 28277

704-815-8022 (Office)
704-909.8158 (Cell)
tshirley@ppmsllc.com

From: Andrews, Edward S [mailto:Edward.S.Andrews@wv.gov]
Sent: Thursday, December 10, 2015 4:05 PM
To: Todd Shirley <tshirley@ppmsllc.com>
Cc: McKeone, Beverly D <Beverly.D.Mckeone@wv.gov>; josh.manley@nrg.com; Patrick E. Ward <PEWard@potesta.com>; Shimshock, John <John.Shimshock@nrg.com>; Dan Traynor <dtraynor@ppmsllc.com>
Subject: WV DAQ Permit Application Incomplete for Morgantown Energy Associates - Morgantown Energy Facility

RE: Application Status: Incomplete
Morgantown Energy Associates
Morgantown Energy Facility
Permit Application No. R14-0007C
Plant ID No. 061-00027

Mr. Shirley:

Your application for a modification permit for a fossil fuel fired cogeneration was received by this Division on November 23, 2015, and assigned to the writer for review. Upon initial review of said application, it has been determined that the application as submitted is incomplete based on the following items:

1. The business plan or financial performance document that was used in projecting the heat input and capacity of the affected unit for operating 2016 through 2020.

2. Please provide justification for excluding the "emissions that could have been accommodated" in the net emission change in your PSD applicability determination.

3. The average and range of F_d factors from past 5 operating year.

Please address the above deficiencies in writing within fifteen (15) days of the receipt of this email. Application review will not commence until the application has been deemed to be technically complete. Failure to respond to this request in a timely manner may result in the denial of the application.

Should you have any questions, please contact me at (304) 926-0499 ext.1214 or reply to this email.

Sincerely,

Edward S. Andrews, P.E.
Engineer
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
304.926.0499 ext. 1214

Morgantown Energy Associates
555 Beechurst Avenue
Morgantown, West Virginia 26505
304.284.2500 Phone
304.284.2509 Fax

MEA
Morgantown Energy Associates

VIA E-MAIL: Edward.S.Andrews@wv.gov

December 18, 2015

RECEIVED
DEC 21 2015
DIV OF AIR QUALITY

ID # 061-00027
Reg R14-0007C
Company MEA
Facility MEA Initials

Mr. Edward S. Andrews
Engineer – Division of Air Quality
West Virginia Department of Environmental Protection
601 57th Street SE
Charleston, WV 25304

RE: "Permit Application Incomplete" Response
Morgantown Energy Associates

Dear Mr. Andrews:

In response to the items in your letter received on December 10, 2015, MEA is providing the following response in regards to the three matters referenced in your letter:

1. **The business plan or financial performance document that was used in projecting the heat input and capacity of the affected unit for operating 2016 through 2020.**

   The requested 2016 thru 2020 financial projections used as the basis of the heat input and capacity in the application calculations is attached to this email. Please note that MEA is submitting this information under a request for Confidential Business Information (CBI).

2. **Please provide justification for excluding the "emissions that could have been accommodated" in the net emission change in your PSD applicability determination.**

   Actual emissions achieved during the look back period were used to calculate the "Excludable Emissions". Therefore, these emissions could have been accommodated during the baseline period and the unit is capable of accommodating them in the future.

   The "emissions that could have been accommodated" are identified in the row of the Table shown in Appendix 1 titled "ANNUALIZED SINGLE MONTH". These emissions were calculated using the maximum monthly emissions of each regulated NSR pollutant from the past 5 years ("MONTH (from 5 Year Total Plant Tons Baseline)") and multiplying each by 12 to calculate the maximum emissions that could have

Entire Document
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been accommodated in a single year of operation. This is both a realistic and conservative approach in calculating "emissions that could have been accommodated" and reflects actual baseline operating hours of the unit including typical maintenance and outages.

3. **The average and range of F_d factors from past 5 operating year.**

   The average of the F_d factors from the past 5 operating years is 9505. The range of F_d factors from the same period is 9045 – 10121.

If you have any questions or comments about the information provided, please do not hesitate to contact Dan Traynor at (610) 390-3522 or Todd Shirley at (704) 815-8022.

Very truly yours,

Todd Shirley

Todd Shirley
Projects General Manager

Enclosures

cc: File (w/enclosures)

Sample Cover Document
Confidential Information

This sample form contains each of the required elements for the cover document required under 45CSR31. The person submitting this form may wish to attach an additional page(s) to provide adequate justification under the "Rationale" section of the form.

Company Name	Morgantown Energy Associates (MEA)	Responsible Official		Mr. Todd Shirley
Company Address	555 Beechurst Ave	Confidential Information Designee in State of WV	Name	Mr. Daryl Miller
	Morgantown, WV		Title	Plant Manager
	26505		Address	555 Beechurst Ave
Person/Title *Submitting* Confidential Information	Todd Shirley			Morgantown, WV 26505
	Projects General Manager		Phone	304.284.2520
			Fax	304.284.2509

Reason for Submittal of Confidential Information:
On December 10, 2015 Mr. Ed Andrews requested that Morgantown Energy Associates provide a business plan of financial document used as the basis of the projections for MEA requested permit modification. Morgantown Energy Associates requests this information be granted CBI protection due to the potential economic harm if this information was provided to MEA customers, competitors and or suppliers. **Permit Application No. R14-0007C** **Plant ID No. 061-00027**

Identification of Confidential Information	Rationale for Confidential Claim	Confidential Treatment Time Period

Identification of Confidential Information	Rationale for Confidential Claim	Confidential Treatment Time Period
Confidential information include any information related to financial projections including energy and other revenues, commodity and services pricing and MEA financial information.	Provide justification that the criteria set forth in § 45CSR31-4.1.a - e have been met. *a. Confidentiality of MEA financial projections has not been waived or withdrawn by MEA.* *b. MEA protects this data by restricting its access to employees who have a "need to know, " and by requiring employees and customers who have access to this information to sign confidentiality agreements.* *c. Financial projection data is not reasonably obtainable without MEA's consent by use of legitimate non-discovery means. MEA keeps this information secured on an internal network with restricted access to the data.* *d. The data held confidential is not emissions information nor is required to be disclosed by a statue.* e. Financial projections *are crucial to MEA's business interests. Disclosure of this information could allow suppliers and or competitors to alter the demand of the commodities used by MEA, potentially altering the price of commodities bought or sold by MEA and would do substantial harm to MEA 's competitive position*	

Responsible Official Signature:	Todd Shumley
Responsible Official Title:	Project General Manager
Date Signed:	December 18, 2015

NOTE: Must be signed and dated in **BLUE INK**.

(cofc.wpd)
WVDEP-DAQ: Revised 3/02

COMPLETENESS DETERMINATION -- CONFIDENTIAL BUSINESS INFORMATION (CBI)

		YES	NO
1)	Has each page of CBI been marked **"Claimed Confidential"** and dated?	☒	☐
2)	Is CBI submitted on colored paper? (Only applies to documents the size of 8½" × 14" or less.)	☒	☐
3)	Has applicant submitted a cover document containing the following information:		
	A. Identity of person making submission;	☒	☐
	B. Reason for submission;	☒	☐
	C. Name, address in State of West Virginia and telephone number of designee who shall be contacted in accordance with §45CSR31-3.3.b.;	☒	☐
	D. Identification of each segment of information claimed confidential;	☒	☐
	E. Period of time confidential treatment desired; and	☒	☐
	F. Signature of responsible official or an authorized representative.	☒	☐
4)	Has applicant provided justification that the following criteria have been met:		
	A. The claim of confidentiality has not expired by its terms, nor been waived or withdrawn;	☒	☐
	B. The person asserting the claim of confidentiality has satisfactorily shown that it has taken reasonable measures to protect the confidentiality of the information, and that it intends to continue to take such measures;	☒	☐
	C. The information claimed confidential is not, and has not been, reasonably obtainable without the person's consent by other persons (other than governmental bodies) by use of legitimate means (other than discovery based on a showing of special need in a judicial or quasi-judicial proceeding);	☒	☐
	D. No statute specifically requires disclosure of the information; and	☒	☐
	E. Either --		
	(i) The person has satisfactorily shown that disclosure of the information is likely to cause substantial harm to the business's competitive position; or	☒	☐

		YES	NO
	(ii) The information is voluntarily submitted information, and its disclosure would be likely to impair the State's ability to obtain necessary information in the future.	☐	☐
5)	A. Has applicant submitted CBI in a "redacted" format, i.e., a complete set of the information on white paper with the CBI blacked or whited out and the words **"Redacted Copy - Claim of Confidentiality"** marked on each page which contains confidential information?	☒	☐
	B. If CBI is included in a drawing or blueprint, has applicant submitted a "redacted" copy with the words **"Redacted Copy - Claim of Confidentiality"** marked on each page and the legend or title of the drawing included on each page? (Redacted copy may be 8½" × 11" in size)	☒	☐
6)	Does information claimed CBI include any "emission data"? (See definition of "types and amounts of air pollutants discharged" in §45CSR31 and §45CSR31B and any DAQ guidance).	☐	☒
	If "YES", that information may not be claimed CBI.		

NOTE:
If any of the above-required elements has been omitted, notify applicant of omission(s) when informing applicant of the Completeness Determination associated with the permit.

RECOMMENDATION:
Based upon my review of the attached information claimed CBI and after verification that each of the required elements listed above has been included in the information, I believe the applicant has made a credible showing that a trade secret is in jeopardy, and I therefore recommend that the Division of Air Quality treat such information as "Confidential".

SIGNATURE ____________________ DATE ____________________

If the permit engineer is unable to make the above recommendation, explain below how the submitted information is deficient and notify applicant of such deficiency, giving applicant an opportunity to remedy, or discuss such deficiency with supervisors and counsel.

Morgantown Energy Associates

Financial Projections

($ in 000s)

	12/31/16	12/31/17	12/31/18	12/31/19	12/31/20
Months	12	12	12	12	12
Days	366	365	365	365	366
Operations					
Electric Generation (mWh)	415,034	394,190	413,900	413,900	415,034
Capacity Factor - net electrical	94.5%	90.0%	94.5%	94.5%	94.5%
Revenues					
Energy Revenues					
Generation (mWh)	415,034	394,190	413,900	413,900	415,034
Energy Rate ($/mWh)	[redacted]				
Energy Revenue					
Capacity Revenues					
Generation (mWh)	415,034	394,190	413,900	413,900	415,034
Base Capacity Rate ($/mWh)	[redacted]				
Fixed O&M Capacity Revenues					
Steam Revenues					
Steam Output (lbs/hr)	[redacted]				
Annual Hours	8,784	8,760	8,760	8,760	8,784
Total Steam Production (klbs)	[redacted]				
Total Steam Revenue	[redacted]				
Beneficial Ash Sales					
Total Beneficial Ash Sales Revenue	[redacted]				
Total Annual Revenues	[redacted]				
Fuel & Consumption Expenses					
Fuel Costs					
Electric Generation (mWh)	415,034	394,190	413,900	413,900	415,034
Steam Equivalent Generation (mWh)	[redacted]				
Total Generation (mWh)					
Blended Heating Value					
Blended Heat Rate					
Total Tons	410,546	392,095	409,542	409,542	410,546
Waste Coal #2 $s	[redacted]				
Limestone Costs					
Fuel Sulfur Tons	[redacted]				
Tons of Limestone / Tons of Fuel Sulfur					
Tons of Lime Consumed	128,145	122,386	127,832	127,832	128,145
Total Lime Cost	[redacted]				
Ash Expense					
Fuel Cycle Solid tons	[redacted]				
Fuel to Ash Conversn (% of fuel cycle tons)					
Tons of Ash Created					
Total Ash Cost					
Aux Boiler fuel Cost					
Aux Boiler Generated Steam	[redacted]				
MMBtu's/Year					
Total Aux Boiler Cost					
Total Fuel & Consumption Expenses	[redacted]				
Revenues Less Fuel Costs	[redacted]				
Total Heat Input CFBs	6,145,053	5,868,871	6,130,028	6,130,028	6,145,053
Total Heat Input Aux Boilers	87,968	87,968	87,968	87,968	87,968
Total Heat Input	6,233,021	5,956,839	6,217,996	6,217,996	6,233,021
Total Emission Allowances	[redacted]				
Gross Margin	[redacted]				
Fixed & Variable Operating Expenses					
Total Owner Expenses	[redacted]				
Total Operator Expenses					
Major Maintenance Expense					
Total Fixed & Variable Operating Expenses	[redacted]				
Cash After Operating Expenses	[redacted]				
Interest Income	[redacted]				
Debt Service					
EEPA Reserve funding					
CAPEX					
Excess Cash after Debt Service and Other Funding	[redacted]				

Andrews, Edward S

From: James Kotcon <jkotcon@gmail.com>
Sent: Thursday, December 24, 2015 12:20 PM
To: Andrews, Edward S; Durham, William F
Subject: Comments on Permit modification for R14-0007C filed by Morgantown Energy Associates (MEA)
Attachments: SC-MEA Air Permit FinalComments 12-23-2015.doc

Please accept the attached comments on behalf of the West Virginia Sierra Club.

Jim Kotcon
304-293-8822 (office)
304-594-3322 (home)

ID # 061-00027
Reg R14-0007C
Company MEA
Facility Morgantown Plant Initials ESA

Entire Document
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SIERRA CLUB
FOUNDED 1892

SIERRA CLUB
WEST VIRGINIA CHAPTER

P. O. Box 4142
Morgantown, WV 26504

Dec. 23, 2015

Division of Air Quality, DEP
601 57th Street SE
Charleston, WV 25304
Attn: Ed Andrews

RE: Permit modification for R14-0007C filed by Morgantown Energy Associates (MEA)

Dear Mr. Andrews:

Please accept the following comments on behalf of the West Virginia Chapter of Sierra Club. The Sierra Club appreciates the opportunity to comment on this application, because we believe it sets important precedents in meeting Mercury and Air Toxics Standard, especially as West Virginia moves forward with other air pollution controls and EPA requirements.

1. Public Notice Requirements:

The Sierra Club questions the validity of the legal notice for this permit modification. The notice was published on Nov. 25, 2015, and indicates that "Installation of the SNCR system will proceed upon issuance of the revised permit and is anticipated to start in fourth quarter 2015 and begin operating in January 2016." However the permit application at Section 14A. indicates the date of the anticipated installation as "11/1/2015 – 2/28/2015" and indicates "Project commenced in accordance with WVDEP MATS extension dated 12/15/2014 and related MEA correspondence." (past tense in the original). This it is not clear whether this project has commenced construction, but it seems unlikely that MEA can begin operation in January 2016 if a permit is not issued until after Dec. 24, 2015. We note with regard to "pre-construction" activities that, as specified in 45-CSR-13-5.3, "All activities … shall be conducted solely at the risk of the owner or operator pf the stationary source and, in undertaking such activities, the owner or operator shall not assert as any argument, including legal or equitable, in any proceeding (administrative, civil or criminal) that such activities or investment has occurred." This, if construction has begun, as implied in the application, that should have no bearing on any decision by DEP as to whether or not to issue a permit.

We further question whether the public notice is adequate because it fails to describe "the type and amount of air pollutants proposed to be discharged" as specified in 45-CSR-14 section 17.1. The legal notice indicates that "The applicant estimates that there is no increase in emission from the change…", but there is no indication of what "type or amount of air pollutants" are proposed to be emitted. We note that MEA is the largest single source of air emissions within the City limits of Morgantown, but no one would be able to discern this from the public notice published Nov. 25. The SNCR system proposed would involve adding significant amounts of ammonia or urea injected into the flue gas, creating a significant potential for emissions and adverse impacts to the community. As noted below, SNCR systems require precise mixing of the ammonia with flue gases, or significant emissions can result. **We recommend that the public notice be re-advertised with correct start dates and emissions projections, including notice of ammonia or urea usage, and that the public have an additional 30 days to comment on the proposed change.**

2. Mercury Pollution Emission Limits

The application (section D) indicates that the proposed change is to comply with the Mercury and Air Toxics rule, and would involve an increase in limestone injection rates and fuel feed, resulting in exceedances of NOx emissions limits. To meet existing NOx limits, MEA proposes to add Selective Non Catalytic reduction, but requests that emissions limits, except for SO2, remain at current limits.

The whole reason for the change is to comply with the mercury rule, but no change in the emissions limit is specified for mercury in the application for the proposed revision, even though the application indicates a 1-3 % increase in coal gob being fed into the system. Furthermore, MEA proposes no actual reduction in the emissions limit of 0.021 lbm/hr in their existing Title V permit, nor does the proposed limit account for the increased fuel consumption. MEA's existing limit of 0.021 lbm/hr is equivalent to 183 lb/yr, well in excess of the level to qualify as a "Low Emitting Electric generating unit" (LEE); thus we believe that **continuous emissions monitoring for mercury is required under MATS**. MEA states that they anticipate that the facility will qualify as LEE, however no data or operating changes are proposed to demonstrate this. **We recommend that DEP reject the designation as LEE and require continuous monitoring to document compliance with the MATS. We further request that the mercury emissions limit be reduced as much as is practicable to reduce overall potential for mercury exposure in Morgantown.**

3. Ammonia Emission Limits

Attachment G of the MEA application (Process description) indicates that as much as 1500 gallons of either anhydrous ammonia or urea would be stored on site, and injected into the flue gas. In either case NH2 radicals bind with NOx . However, unreacted NH2 would be exhausted through the stack, creating an "ammonia slip" which creates potential human health hazards (US-EPA at http://www3.epa.gov/ttncatc1/dir1/fsncr.pdf). **We recommend that emissions limits for ammonia be imposed at levels as low as practicable, and in no event should this exceed 10 ppm.**

In addition, ammonia in the flue gas can form ammonium sulfates which deposit in the ash, but which can off-gas as ammonium when in an aqueous environment. Because most of the coal combustion residues from MEA are disposed of at surface mines, it should be assumed that these will be in an aqueous environment, and ammonia off-gassing can occur. Ammonia content in ash greater that 5 ppm can result in ammonia off-gassing. **We recommend that ammonia content of ash be monitored, and unless MEA demonstrates that it never exceeds 5 ppm, emissions limits for ammonia at disposal sites must also be established and monitoring be required.**

4. Nitrous Oxides Emission Limits

When either ammonia or urea react with NOx, significant amounts of N_2O can form. N_2O formation is greater with urea than ammonia (EPA 2002 at http://www3.epa.gov/ttn/catc/dir1/cs4-2ch1.pdf). Since N_2O is a greenhouse gas, its emissions must be monitored and controlled. **We recommend that emissions limits be established for N_2O at the lowest practicable level and monitoring be required.**

5. Nitrogen Oxides Emission Limits.

The whole rationale for installing SNCR is to reduce NOx emissions, yet MEA proposes no reduction in the existing NOx limits of 0.4 lbm/mmBtu. SNCR typically achieves NOx reductions of 30-50 %, and higher emissions reductions are achievable. **Therefore we recommend that the NOx limit be lowered to the lowest practicable level, not more than 0.28 lb/mmBtu, and preferably to 0.2 lb/mmBtu or lower. Alternatively, we recommend that Selective Catalytic Reduction be required.** SCR achieves far higher NOx reductions (90 % or more) and is an available control technology.

6. Acid Gases

The existing Title V permit has no emissions limits for acid gases such as hydrofluoric, hydrochloric, or sulfuric acids. These are extremely hazardous materials and appropriate limits are needed. **We recommend that these be established at the lowest practicable level.**

Thank you for the opportunity to comment on this application.

Sincerely,

James Kotcon, Chair
Energy Committee
414 Tyrone Avery Road
Morgantown, WV 26508
304-594-3322 (home)
304-293-8822 (office)

Andrews, Edward S

From: Null, Gregory L
Sent: Friday, December 04, 2015 2:37 PM
To: Andrews, Edward S
Subject: Morgantown Energy Associates Permit Application Fee

This is the receipt for payment received from:

Morgantown Energy Associates, ck# 35207, dated 12/2/15, $2,500
R14-0007C, id 061-00027

OASIS Deposit CR 1600062050, December 5, 2015

Ed

POTESTA
Engineers and Environmental Consultants

TRANSMITTAL MEMO

7012 MacCorkle Avenue, SE, Charleston, WV 25304 ▪ Phone: (304) 342-1400 ▪ Fax: (304) 343-9031

To: Director
Division of Air Quality
WV Department of Environmental Protection
601 57th Street, SE
Charleston, West Virginia 25304

Date: December 2, 2015

Project No.: 0101-14-0438-001

RECEIVED
DEC 03 2015

Sent Via: ☐ Mail ☐ Federal Express ☐ United Parcel Service
☒ Hand Carried ☐ Other: ______

Quantity	Description
1	Check No. 35207 of Morgantown Energy Associates payable to WV Department of Environmental Protection in the amount of $2,500 covering additional application fee (NESHAP) for Modification Application for Mercury and Air Toxics Standard Compliance with A Selective Non-Catalytic Reduction (SNCR) System – Morgantown Energy Associates
	ID # 061-
	Reg R14-0007C
	Company MEA
	Facility Morgantown Initials EK

Remarks:

Entire Document
NON-CONFIDENTIAL

By: Patrick E. Ward/rlh

c: Josh Manley, Morgantown Energy Associates

POTESTA
Engineers and Environmental Consultants

TRANSMITTAL MEMO

7012 MacCorkle Avenue, SE, Charleston, WV 25304 ▪ Phone: (304) 342-1400 ▪ Fax: (304) 343-9031

To: Director
Division of Air Quality
WV Department of Environmental Protection
601 57th Street, SE
Charleston, West Virginia 25304

Date: November 30, 2015

Project No.: 0101-14-0438-001

RECEIVED
DEC 01 2015
WV DEP / DIV OF AIR QUALITY

Sent Via: ☐ Mail ☐ Federal Express ☐ United Parcel Service
☒ Hand Carried ☐ Other: ____

Quantity	Description
1	Affidavit of Publication for Modification for Mercury and Air Toxics Standard Compliance with A Selective Non-Catalytic Reduction (SNCR) System – Morgantown Energy Associates
	ID # 061-00027
	Reg R14-0007C
	Company
	Facility ______ Initials ______

Remarks:

By: Patrick E. Ward/rlh

c: Josh Manley, Morgantown Energy Associates

Entire Document
NON-CONFIDENTIAL

010079167 November 25

AIR QUALITY PERMIT NOTICE
Notice of Application

Notice is given that Morgantown Energy Associates has applied to the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), for a Modification for the installation of a selective non-catalytic reduction (SNCR) system to aid in meeting the requirements of the 40CFR63, Subpart UUUUU, Mercury and Air Toxics Standards (MATS) for the Morgantown Energy Facility, a cogeneration facility, located on Beechurst Avenue, in Morgantown, Monongalia County, West Virginia. The latitude and longitude coordinates of the facility are: 39.640234 and -79.961871.

The applicant estimates that there is no increase in emission from the change in the method of operations and additional control being applied to the source. The MATS requirements mandate a reduction in sulfur dioxides. Meeting the MATS sulfur dioxide requirements requires a limestone addition to the Circulating Fluidized Bed (CFB) system and increases the heat required for limestone calcination to activate for sulfur dioxide control. The SNCR system is being added to allow flexibility in meeting nitrogen oxide emissions from the CFB system. These changes trigger a regulatory definition of a change in the method of operation and require a permit revision for the change and to make the control requirements enforceable by the West Virginia Department of Environmental Protection under the Division of Air Quality and the United States Environmental Protection Agency.

Installation of the SNCR system will proceed upon issuance of the revised permit and is anticipated to start in fourth quarter 2015 and begin operating in January 2016. Written comments will be received by the West Virginia Department of Environmental Protection, DAQ, 601 57th Street, Charleston, WV 25304, for at least 30 calendar days from the date of publication of this notice.

Any questions regarding this permit application should be directed to the DAQ at (304) 926 0499, Extension 1250, during normal business hours.

Dated this the 25th day of November, 2015.

By: Morgantown Energy Associates
Todd Shirley
Projects General Manager
555 Beechurst Avenue
Morgantown, West Virginia 26505

PUBLISHER'S CERTIFICATE

____

vs.

____

STATE OF WEST VIRGINIA
COUNTY OF MONONGALIA

I **Eric Wilson** Advertising Director of THE DOMINION POST, a newspaper of general circulation published in the City of Morgantown, County and State aforesaid, do hereby certify that the annexed

Legal Notice

was published in the said THE DOMINION POST once a week for **1** successive weeks commencing on the **25th** day of **Nov.**, 2015 and ending on the **25th** day of **Nov.**, 2015

The publisher's fee for said publication is **$82.77**

Given under my hand this **25th** day of **November**, **2015**

(signature)

(SEAL)

Advertising Director of THE DOMINION POST

Subscribed and sworn to before me this **25th** day of **November**, **2015**

Kelley V. Felton

Notary Public of Monongalia County, W. Va.

My commission expires on the 13th day of December 2019

Official Seal
Notary Public, State of West Virginia
Kelley V. Felton
500 Mylan Park Lane
Morgantown WV 26501
My Commission Expires December 13, 2019

Adkins, Sandra K

From:	Adkins, Sandra K
Sent:	Monday, November 30, 2015 1:46 PM
To:	'tshirley@ppmsllc.com'; 'josh.manley@morgantownenergy.com'; 'peward@potesta.com'
Cc:	McKeone, Beverly D; Andrews, Edward S
Subject:	WV DAQ Permit Application Status for Morgantown Energy Associates; Morgantown

RE: Application Status
Morgantown Energy Associates
Morgantown
Plant ID No. 061-00027
Application No. R14-0007C

Mr. Shirley,

Your application for a modification permit for the Morgantown facility was received by this Division on November 23, 2015, and was assigned to Ed Andrews. The following items were not included in the initial application submittal:

Original affidavit for Class I legal advertisement not submitted.

Application fee AND/OR additional application fees:
**$2,500 NESHAP*

These items are necessary for the assigned permit writer to continue the 30-day completeness review.

Within 30 days, you should receive a letter from Ed stating the status of the permit application and, if complete, given an estimated time frame for the agency's final action on the permit.

Any determination of completeness shall not relieve the permit applicant of the requirement to subsequently submit, in a timely manner, any additional or corrected information deemed necessary for a final permit decision.

Should you have any questions, please contact the assigned engineer, Ed Andrews, at 304-926-0499, extension 1214.