Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Draft/Proposed Permit and Fact Sheet for Kentucky Power Company's Mitchell Plant - R30-05100005-2025

1 message

McCumbers, Carrie <carrie.mccumbers@wv.gov> Fri, Mar 21, 2025 at 1:19 AM
To: "Roberts, Daniel P" <daniel.p.roberts@wv.gov>

Dan,

Attached are my comments on the permit and fact sheet. I don't need to see these documents after you make the changes. Just go ahead and give them to Stephanie so she can send everything out and update the website for Monday. For Subpart UUUUU, the requirements changed and I made some updates. This regulation, however, is one of the ones expected to be changed by the new administration, but hasn't changed yet.

Thanks,
Carrie

On Thu, Mar 20, 2025 at 2:16 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Here is the draft/proposed fact sheet.
>
> Dan
>
> On Thu, Mar 20, 2025 at 12:36 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:
>
>> Carrie,
>>
>> Hey. Here is the draft proposed permit for your review. I am working on cleaning up and double checking the fact sheet and will send it shortly.
>>
>> Matt Palmer got back to me and confirmed that there was never an official acknowledged name change from Kentucky to Wheeling Power. I will forward the copy of an email which he sent me that ties this up. So, the documents will use Kentucky Power Company at this time, but he said they may submit the name change forms in the near future (probably before the comment period expires).
>>
>> Thanks,
>> Dan

2 attachments

Draft FactSheet R30-05100005-2025 3-20-25 Carrie's comments.docx
107K

Draft Permit R30-05100005-2025 3-20-25 Carrie's comments.docx
2081K

West Virginia Department of Environmental Protection
Harold D. Ward
Cabinet Secretary

Permit to Operate

Pursuant to
Title V
of the Clean Air Act

Issued to:
Kentucky Power Company
Mitchell Plant
R30-05100005-2025

____
Laura M. Crowder
Director, Division of Air Quality

Issued: [Date of issuance] • Effective: [Equals issue date plus two weeks]
Expiration: [5 years after issuance date] • Renewal Application Due: [6 months prior to expiration]

Permit Number: **R30-05100005-~~2019~~2025**
Permittee: **Kentucky Power Company (d.b.a. American Electric Power)**
Facility Name: **Mitchell Plant**
Permittee Mailing Address: **1 Riverside Plaza, Columbus, Ohio 43215-2373**

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45CSR30 C *Requirements for Operating Permits. The permittee identified at the above-referenced facility is authorized to operate the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.*

Facility Location:	Cresap/Moundsville, Marshall County, West Virginia
Facility Mailing Address:	Post Office Box K, Moundsville, West Virginia 26041
Telephone Number:	304-843-6000
Type of Business Entity:	Corporation
Facility Description:	Electric Generation Service
SIC Codes:	Primary 4911; Secondary N/A; Tertiary N/A
UTM Coordinates:	516.00 km Easting $ 4409.00 km Northing $ Zone 17

Permit Writer: Dan Roberts

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.

Issuance of this Title V Operating Permit does not supersede or invalidate any existing permits under 45CSR13, 14 or 19, although all applicable requirements from such permits governing the facility's operation and compliance have been incorporated into the Title V Operating Permit.

Table of Contents

1.0 Emission Units and Active R13, R14, and R19 Permits

1.1. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed [1]	Design Capacity [2]	Control Device [3]
Boilers & Associated Equipment					
Unit 1	1E	Boiler: Foster Wheeler, Model # 2-85-303	1971	7020 mmBtu/hr	High efficiency ESP, LNB, SCR, FGD
Unit 2	2E	Boiler: Foster Wheeler, Model # 2-85-304	1971	7020 mmBtu/hr	High efficiency ESP, LNB, SCR, FGD
Aux 1	Aux ML1	Boiler: Foster Wheeler, Model # SD-25	1970	663 mmBtu/hr	FGR/LNB
17S	17E	Unit 1 Emergency Diesel Driven Fire Pump Engine – 2023 Cummins CFP7E-F60 Certificate No. PCEXL0409AAB-006 (Tier 3)	2023	249 hp	None
18S	18E	Unit 2 Emergency Diesel Driven Fire Pump Engine – 2024 Cummins CFP9E-F10 Certificate No. RCEXL0540AAB-009 (Tier 3)	2024	275 hp	None
EG-1	EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	2014	3,717 bhp @ 1,800rpm	None
EGT01	EGT01	Diesel Fuel Storage Tank for EG-1	2014	4,800 gallons	None
EG-2	EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	2014	3,004 bhp @ 1,800rpm	None
EGT02	EGT02	Diesel Fuel Storage Tank for EG-2	2014	4,800 gallons	None
LF DEG	LF DEG	Landfill Leachate Collection Sump Emergency Diesel Driven Generator, 2019 Cummings C300DQDAC model	2020	464 bhp 300 kW	None
LF DEGT	LF DEGT	Diesel Fuel Storage Tank for LF DEG	2020	600 gallons	None
LF DEG2	LF DEG2	Landfill Leachate Pond Diesel Emergency Generator, 2023 Cummins QSG12 Model Certificate No. PCEXL12.0AAA-049 (Tier 3)	2023	513 bhp 400 kW	None
LF DEGT2	LF DEGT2	Diesel Fuel Storage Tank for LF DEG2	2023	600 gallons	None
Coal & Ash Handling					
BU	BU	Barge Unloader (unload barge onto Conveyor R1	1971	4,000 TPH	WS, PE, MC
Station R1	Sta-R1	Conveyor R1 and drop points to Conveyor R2	1971	3,000 TPH	FE, MC
C-R2	C-R2	Conveyor R2 (transfer to Station R2)	1971	3,000 TPH	WS, PE, MC
RCU	RCU	Rail Car Unloader (unload rail cars to feeders R6-1, R6-2 and R6-3)	April, 1974	3,000 TPH	WS, MC

R6-1, R6-2, R6-3	R6-1, R6-2, R6-3	Feeders R6-1, R6-2, R6-3 (transfer points to Conveyor R7)	April 1974	1,400 TPH	PE, MC
C-R7	C-R7	Conveyor R7 (transfer to Station R2)	April 1974	3,000 TPH	WS, PE, MC
Station R2	Sta-R2	Drop point to coal crusher or conveyor R3	April 1974	N/A	FE, MC
CR-R2	CR-R2	Coal Crusher	1971	2,500 TPH	FE, MC
C-R3	C-R3	Conveyor R3 (transfer to Station R3)	1971	3,000 TPH	PE, MC
Station R3	Sta-R3	Drop point to conveyor R4 or R11	1971	N/A	FE, MC
C-R11	C-R11	Conveyor R11 (transfer to radial portable Conveyor R12)	1971	3,000 TPH	PE, MC
C-R12	C-R12	Radial Portable Conveyor R12 (transfer to temporary storage pile)	1971	3,000 TPH	MC
C-R4	C-R4	Conveyor R4 (transfer to Station R4)	1971	3,000 TPH	PE, MC
Station R4	Sta-R4	Drop point to Sample System and Conveyor R5; and/or Conveyor R8	1971	N/A	FE, MC
C-R8	C-R8	Conveyor R8 (transfer to Radial Stacker Conveyor R9)	April 1974	3,000 TPH	PE, MC
C-R9	C-R9	Radial Stacker Conveyor R9 (transfer to North Yard Storage Pile – Station R7)	April 1974	3,000 TPH	MC
Station R7	Sta-R7	Drop point from North Yard Storage Pile through Crusher R7-1 to Feeder Conveyor BFR7-1	April 1974	N/A	FE, MC
CR-R7-1	CR-R7-1	Coal Crusher	April 1974	1,000 TPH	FE, MC
BFR7-1	BFR7-1	Feeder BFR7-1 (transfer to Conveyor R10)	April 1974	1,100 TPH	FE, MC
C-R10	C-R10	Conveyor R10 (transfer to truck load out and Station R4)	April 1974	1,100 TPH	PE, MC
C-R5	C-R5	Conveyor R5 (transfer to Drive Tower S1)	1971	3,000 TPH	PE, MC
Drive Tower S1	Drive Tower S1	Drop point to Conveyor R6	1971	N/A	FE, MC
C-R6	C-R6	Conveyor R6 (transfer to Station 2)	1971	3,000 TPH	PE, MC
Station 2	Sta-2	Drop point to Radial Stacker Conveyor 2	1969	N/A	FE, MC
RS-2	RS-2	Radial Stacker 2 (transfer to surge pile)	1969	4,000 TPH	WS, MC
Station 1A	Sta-1A	Drop point from frozen coal storage area 4 through crusher CR-1A to Conveyor 1A	1969	N/A	FE, MC
CR-1A	CR-1A	Coal Crusher	1969	1,000 TPH	FE, MC
C-1A	C-1A	Conveyor 1A (transfer to Station 1B)	1969	1,100 TPH	PE, MC
Station 1B	Sta-1B	Drop point to Conveyor 1	1969	N/A	FE, MC
C-1	C-1	Conveyor 1 (transfer to Station 2)	1969	2,600 TPH	PE, MC
CSA-1	CSA-1	Coal Storage Area #1 (Surge Pile)	1969	Approx. 40 Acres	MC
CSA-2	CSA-2	Coal Storage Area #2 (North Yard Storage Pile)	April 1974	Approx. 40 Acres	MC
CSA-3	CSA-3	Coal Storage Area #3 (Temporary Storage Pile at R3)		Approx. 6 Acres	MC

CSA-4	CSA-4	Coal Storage Area #4 (conveyor from 1B)	1969	Included in CSA-1	MC
SGM1 through SGM16	SGM1 through SGM16	Reclaim Hoppers/Vibratory Feeders (Reclaim Area #1 surge pile) transfers to Conveyors 3A, 3B and 3C	1969	300 TPH each	FE, MC
C-3A	C-3A	Conveyor 3A (transfer to Station 3B)	1969	1,100 TPH	FE, MC
Station 3B	Sta-3B	Drop point to Conveyor 3B	1969	N/A	FE, MC
C-3B	C-3B	Conveyor 3B (transfer to Station 3)	1969	1,100 TPH	FE, MC
C-3C	C-3C	Conveyor 3C (transfer to Station 3)	1969	1,100 TPH	FE, MC
Station 3	Sta-3	Drop point to Conveyors 4E and/or 4W	1969	N/A	FE, MC
C-4E / C-4W	C-4E / C-4W	Conveyors 4E and 4W (transfer to Station 4)	1969	1,100 TPH each	PE, MC
Station 4	Sta-4	Drop point to Sample System, Conveyor 7E and/or 7W, and Conveyor 5 or Emergency Conveyors E25 through E21	1969	N/A	FE, MC
C-7E / C-7W	C-7E / C-7W	Conveyors 7E and 7W (transfer to Station 5)	1969	1,100 TPH each	PE, MC
C-5	C5	Conveyor 5 (transfer to Unit 2 coal silos 3, 4 or 5 and to Conveyor 6)	1969	1,100 TPH	FE, MC
C-6	C-6	Conveyor 6 (transfer to Unit 2 coal silos 1 or 2)	1969	1,100 TPH	FE, MC
C-E25 through C-E21	C-E25 through C-E21	Emergency conveyors E25 through E21 (used in an emergency to transfer coal into Unit 2 coal silos)	1969	500 TPH each	MC
Station 5	Sta-5	Drop point to Conveyor 8 or Emergency Conveyors E11 through E15	1969	N/A	FE, MC
C-8	C-8	Conveyor 8 (transfer to Unit 1 coal silos 3, 4, or 5 and to Conveyor 9)	1969	1,100 TPH	FE, MC
C-9	C-9	Conveyor 9 (transfer to Unit 1 coal silos 1 or 2)	1969	1,100 TPH	FE, MC
C-E11 through C-E15	C-E11 through C-E15	Emergency conveyors E11 through E15 (used in an emergency to transfer coal into Unit 1 coal silos)	1969	500 TPH	MC
Fly Ash Material Handling					
Haul Roads	Haul Roads	Fly Ash Material Haul Roads and Landfill	N/A	N/A	Water Truck
ME-1A	EP-1	Unit 1 Mechanical Exhauster 1A	2012	N/A	Filter/ Separator
ME-1B	EP-2	Unit 1 Mechanical Exhauster 1B	2012	N/A	Filter/ Separator
ME-1C (spare)	EP-3	Unit 1 Mechanical Exhauster 1C	2012	N/A	Filter/ Separator
ME-2A	EP-4	Unit 2 Mechanical Exhauster 2A	2012	N/A	Filter/ Separator
ME-2B	EP-5	Unit 2 Mechanical Exhauster 2B	2012	N/A	Filter/ Separator
ME-2C (spare)	EP-6	Unit 2 Mechanical Exhauster 2C	2012	N/A	Filter/ Separator
FAS-A	EP-7	Fly Ash Silo A	2012	2,160 tons	BVF-A
FAS-B	EP-8	Fly Ash Silo B	2012	2,160 tons	BVF-B

FAS-C	EP-9	Fly Ash Silo C	Future	2,160 tons	BVF-C
WFA-AA	F-1	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-BA	F-2	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-CA	F-3	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	Future	360 tph	MC
WFA-AB (spare)	F-4	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-BB (spare)	F-5	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-CB (spare)	F-6	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	Future	360 tph	MC
TC-A	EP-10, F-7	Transfer dry fly ash from Fly Ash Silo A to Truck via Telescopic Chute	2012	300 tph	TC
TC-B	EP-11, F-8	Transfer dry fly ash from Fly Ash Silo B to Truck via Telescopic Chute	2012	300 tph	TC
TC-C	EP-12, F-9	Transfer dry fly ash from Fly Ash Silo C to Truck via Telescopic Chute	Future	300 tph	TC
LPG	LPG	Generac SG080, Lean Burn Four Stroke, Liquid Propane Gas-fired emergency generator Certificate No. DGNXB08.92NL-011	2013	126 bhp	None
LPT	LPT	Liquid Propane tank for LPG	2013	500 gallons	None
1S – Limestone Material Handling					
BUN-1	BUN-1 (Fugitive)	Limestone Unloading Crane	2006	1,000 TPH	None
RH-1	RH-1 (Fugitive)	Limestone Unloading Hopper	2006	60 Tons	WS, PE
VF-1	VF-1 (Fugitive)	Limestone Unloading Feeder	2006	750 TPH	FE
BC-1	BC-1 (Fugitive)	Limestone Dock/Connecting Conveyor	2006	750 TPH	PE
TH-1	TH-1 (Fugitive)	Limestone Transfer House #1	2006	750 TPH	FE
BC-2	BC-2 (Fugitive)	Limestone Storage Pile Stacking Conveyor	2006	750 TPH	PE
LSSP	LSSP (Fugitive)	Limestone Active/Long-Term Stockpile	2006/2011	155,000 Tons	None
2S – Gypsum Material Handling					
BC-8	BC-8 (Fugitive)	Vacuum Collecting Conveyor	2007	200 TPH	PE
TH-3	TH-3 (Fugitive)	Gypsum Transfer House #3	2007	200 TPH	FE
BC-9	BC-9 (Fugitive)	Connecting Conveyor	2007	200 TPH	PE
TH-4	TH-4 (Fugitive)	Gypsum Transfer House #4	2007	200 TPH	FE

BC-10	BC-10 (Fugitive)	Connecting Conveyor	2007	200 TPH	PE
TH-5	TH-5 (Fugitive)	Gypsum Transfer House #5	2007	200 TPH	FE
BC-11	BC-11 (Fugitive)	Connecting Conveyor	2007	200 TPH	PE
TH-6	TH-6 (Fugitive)	Gypsum Transfer House #6	2007	200 TPH	FE
BC-12	BC-12 (Fugitive)	Stacking Tripper Conveyor	2007	200 TPH	PE
GSP	GSP (Fugitive)	Gypsum Stockpile	2007	15,600 tons	FE
PSR-1	PSR-1 (Fugitive)	Traveling Portal Scraper Reclaimer	2007	1,000 TPH	FE
BC-14	BC-14 Fugitive)	Reclaim Conveyor	2007	1,000 TPH	PE
TH-7	TH-7 (Fugitive)	Transfer House #7	2007	1,000 TPH	FE
BC-13	BC-13 (Fugitive)	Bypass Conveyor	2007	200 TPH	PE
BC-15	BC-15 (Fugitive)	Connecting Conveyor	2007	1,000 TPH	PE
TH-1	TH-1 (Fugitive)	Transfer House #1	2007	1,000 TPH	FE
BC-16	BC-16 (Fugitive)	Transfer Conveyor	2007	1,000 TPH	PE
BL-1	BL-1 (Fugitive)	Barge Loader	2007	1,000 TPH	PE
BC-14	BC-14 (Fugitive)	Reclaim Conveyor Extension	2007	1,000 TPH	PE
TH-8	TH-8 (Fugitive)	Transfer House 8	2007	1,000 TPH	FE
BC-19	BC-19 (Fugitive)	Transfer Conveyor	2007	1,000 TPH	PE
TH-9	TH-9 (Fugitive)	Transfer House 9	2007	1,000 TPH	FE
BC-20	BC-20 (Fugitive)	Transfer Conveyor to 20	2007	1,000 TPH	PE
TH-10	TH-10 (Fugitive)	Transfer House 10	2007	1,000 TPH	FE
BC-21	BC-21 (Fugitive)	Transfer Conveyor to 21	2007	1,000 TPH	PE
BUN-1	BUN-1 (Fugitive)	Clamshell Unloading Crane	2007	1,000 TPH	
RH-4	RH-4 (Fugitive)	Gypsum Unloading Hopper	2007	30 tons	WS, PE
RP-1	RP-1 (Fugitive)	Gypsum Rotary Plow	2007	750 TPH	FE
BC-17	BC-17 (Fugitive)	Dock/Connecting Conveyor	2007	750 TPH	PE

TH-7	TH-7 (Fugitive)	Transfer House #7	2007	750 TPH	FE
BC-18	BC-18 (Fugitive)	Bypass Conveyor	2007	750 TPH	PE
TH-6	TH-6 (Fugitive)	Transfer House #6	2007	750 TPH	FE
3S – Limestone Mineral Processing					
VF-2	VF-2 (Fugitive)	Limestone Reclaim Feeder 2	2007	750 TPH	FE
VF-3	VF-3 (Fugitive)	Limestone Reclaim Feeder 3	2007	750 TPH	FE
BC-3	BC-3 (Fugitive)	Limestone Tunnel Reclaim Conveyor	2007	750 TPH	PE
FB-1	FB-1 (Fugitive)	Emergency Limestone Reclaim Feeder/Breaker	2007	750 TPH	
TH-2	TH-2 (Fugitive)	Limestone Transfer House 2	2007	750 TPH	FE
BC-4	BC-4 (Fugitive)	Limestone Silo A Feed Conveyor	2007	750 TPH	PE
BC-5	BC-5 (Fugitive)	Limestone Silo B Feed Conveyor	2007	750 TPH	PE
BC-6	BC-6 (Fugitive)	Limestone Silo C Feed Conveyor (future)	2007	750 TPH	PE
LSB-1	6E	Limestone Silo A	2007	900 Tons	BH
LSB-2	7E	Limestone Silo B	2007	900 Tons	BH
LSB-3	8E	Limestone Silo C (future)	Future	900 Tons	BH
	(Fugitive)	Vibrating Bin Discharger (one per silo)	2007	68.4 TPH	FE
LSWF-1 LSWF-2 LSWF-3	LSWF-1 (Fugitive) LSWF-2 (Fugitive) LSWF-3 (Fugitive)	Limestone Weigh Feeder (one per silo)	2007	68.4 TPH	FE
	(Fugitive)	Wet Ball Mill (one per silo)	2007	68.4 TPH	FE
4S – Dry Sorbent Material Handling					
	(Fugitive)	Truck Unloading Connection (2)	2007	25 TPH	FE
DSSB 1	10E	Dry Sorbent Storage Silo #1	2007	500 TPH	BH, FE
DSSB 2	11E	Dry Sorbent Storage Silo #2	2007	500 TPH	BH, FE
	(Fugitive)	Aeration Distribution Bins	2007	4.6 TPH	FE
	(Fugitive)	De-aeration Bins	2007	4.6 TPH	FE
	(Fugitive)	Rotary Feeder	2007	4.6 TPH	FE
5S – Coal Blending System					
HTS-1	HTS-1 (Fugitive)	Transfer House #1	2007	3,000 TPH	FE
HSC-1	HSC-1 (Fugitive)	Stacking Conveyor #1	2007	3,000 TPH	PE

HTS-2A	HTS-2A (Fugitive)	Transfer House #2A	2007	3,000 TPH	FE
HSC-2	HSC-2 (Fugitive)	Stacking Conveyor #2	2007	3,000 TPH	PE
HTS-3	HTS-3 (Fugitive)	Transfer House #3	2007	3,000 TPH	FE
HSC-3	HSC-3 (Fugitive)	Stacking Conveyor #3	2007	3,000 TPH	PE
SH-1	SH-1 (Fugitive)	Stacking Hopper SH-1 Transfer to SC-3 (receive coal from plant radial stacker R9)	2007	3,000 TPH	FE
HSC-3 to High Sulfur Pile (CSA-2, existing)	HSC-3 to High Sulfur Pile (Fugitive) (CSA-2, existing)	Transfer from Stacking Conveyor HSC-3 to High Sulfur Pile at existing North Yard Storage Area (CSA-2)	2007	3,000 TPH	Stacking Tube
HVF-1	HVF-1 (Fugitive)	Coal Reclaim Feeder 1	2007	800 TPH	FE
HVF-2	HVF-2 (Fugitive)	Coal Reclaim Feeder 2	2007	800 TPH	FE
HVF-3	HVF-3 (Fugitive)	Coal Reclaim Feeder 3	2007	800 TPH	FE
HVF-4	HVF-4 (Fugitive)	Coal Reclaim Feeder 4	2007	800 TPH	FE
HVF-1 through HVF-4 to HRC-1 (Transfer)	HVF-1 through HVF-4 to HRC-1 (Fugitive) (Transfer)	Transfer from Vibrating Feeders HVF-1 through HVF-4 to Reclaim Conveyor HRC-1	2007	1,600 TPH	FE
HRC-1	HRC-1 (Fugitive)	Coal Tunnel Reclaim Conveyor	2007	1,600 TPH	PE
HTS-2B	HTS-2B (Fugitive)	Coal Transfer House #2B	2007	1,600 TPH	FE
HRC-2	HRC-2 (Fugitive)	Reclaim Conveyor #2	2007	1,600 TPH	PE
HTS-4	HTS-4 (Fugitive)	Coal Transfer House #4	2007	1,600 TPH	FE
HRC-3	HRC-3 (Fugitive)	Reclaim Conveyor #3	2007	1,600 TPH	PE
HTS-5	HTS-5 (Fugitive)	Coal Transfer House #5	2007	1,600 TPH	FE
SB-1	SB-1 (Fugitive)	Surge Bin #1	2007	80 Tons	FE
HBF-1A	HBF-1A (Fugitive)	Belt Feeder 1A	2007	800 TPH	PE
HBF-1B	HBF-1B (Fugitive)	Belt Feeder 1B	2007	800 TPH	PE
HBF-1A/1B to BF-4E/4W	HBF-1A/1B to BF-4E/4W (Fugitive)	Transfer from Belt Feeders HBF-1A and HBF-1B to Existing Coal Conveyors 4E and 4W	2007	1,600 TPH	FE

6S, 7S – Emergency Quench Water System

6S	15E	Diesel Engine on Quench Pump #1	2007[1]		

[1] Construction *commenced* (as defined in 40 C.F.R. §63.2) on or about June 14, 2004 for engine 6S.
[2] Construction *commenced* (as defined in 40 C.F.R. §63.2) on or about June 14, 2004 for engine 7S.

				60 HP (approx.)	FE
7S	16E	Diesel Engine on Quench Pump #2	2007 [2]	60 HP (approx.)	FE
9S – Magnesium Hydroxide Material Handling System					
MHM-1	MHM-1	Magnesium Hydroxide Mix Tank #1	2007	1,000 gallons	N/A
MHM-2	MHM-2	Magnesium Hydroxide Mix Tank #2	2007	1,000 gallons	N/A

Tank #28	Tank #28	Diesel Fire Pump Fuel Tank – U1	2023	300 gallons	N/A
Tank #29	Tank #29	Diesel Fire Pump Fuel Tank – U2	2024	300 gallons	N/A
Tank #30	Tank #30	3 Compartment Oil Tank – Tractor Shed Oil Room	~1995	920 gallons	N/A
Tank #31	Tank #31	Single Compartment Oil Tank – Tractor Shed	~1995	560 gallons	N/A
Tank #33	Tank #33	Urea Receiving Hopper	2007	45 tons	FE
Tank #34	Tank #34	No.2 Fuel Oil Tank – Drain Receiver Tank – overflow tank	2001	1,000 gallons	N/A
Tank #35	Tank #35	TK103-100 Urea Solution Storage Tank	2007	200,000 gallons	N/A
Tank #36	Tank #36	TK102-100 Urea Mix Tank	2007	2,700 gallons	N/A
Tank #37	Tank #37	CPS Lime Slurry Tank #1	2007	750 gallons	N/A
Tank #38	Tank #38	CPS Lime Slurry Tank #2	2007	750 gallons	N/A
Tank #39	Tank #39	CPS Equalization Tank #1	2007	254,513 gallons	N/A
Tank #40	Tank #40	CPS Equalization Tank #2	2007	254,513 gallons	N/A
Tank #41	Tank #41	CPS Ferric Chloride Mix Tank #1	2007	9,200 gallons	N/A
Tank #42	Tank #42	CPS Ferric Chloride Mix Tank #2	2007	9,200 gallons	N/A
Tank #43	Tank #43	CPS Ferric Chloride Bulk Storage Tank	2007	8,800 gallons	N/A
Tank #45	Tank #45	CPS Polymer Totes (2)	2007	225 gallons each	N/A
Tank #46	Tank #46	Emergency Quench Pump #1 Diesel Tank	2007	70 gallons	N/A
Tank #47	Tank #47	Emergency Quench Pump #2 Diesel Tank	2007	70 gallons	N/A
Tank #49	Tank #49	No. 2 Fuel Tank – SW Corner of CSA-2	2008	2000 gallons	N/A
Tank #50	Tank #50	Gypsum Storage Building Fuel Oil Tank	2009	1,000 gallons	None
Tank #51	Tank #51	Highway Grade Diesel Tank #1	2011	1,000 gallons	None
Tank #52	Tank #52	Limestone Storage Pile Diesel Tank #1	2011	500 gallons	None
	Fugitive	Rock Salt Storage Pile (roadway ice control)	2010 and 2014	600 tons	Enclosure
Tank #53	Tank #53	Landfill Building Furnace Fuel Oil Tank	2018	2,000 gallons	N/A
Tank #54	Tank #54	Landfill Gasoline Tank	2018	520 gallons	N/A
Tank #55	Tank #55	Kerosene Tank	2015	1,000 gallons	N/A
Tank #56	Tank #56	CPS Coagulant Tank	2019	5,000 gallons	N/A
Tank #57	Tank #57	Unit 1 Scale Inhibitor Tank	2015	3,500 gallons	N/A
Tank #58	Tank #58	Unit 2 Scale Inhibitor Tank	2015	3,500 gallons	N/A
Tank #59	Tank #59	Unit 1 Dispersant Tank	2015	5,000 gallons	N/A
Tank #60	Tank #60	Unit 2 Dispersant Tank	2015	5,000 gallons	N/A
Tank #61	Tank #61	Unit 1 Ferric Chloride Tank	2015	1,500 gallons	N/A
Tank #62	Tank #62	Unit 1 Ferric Chloride Tank	2015	2,500 gallons	N/A
Tank #63	Tank #63	FGD corrosion inhibitor tank	2015	5,000 gallons	N/A
		Landfill Building Fuel Oil Fired Furnace Clean Burn Model CB-3250	2018	0.325 MMBtu/hr	None
Tank #64	Tank #64	Bioreactor Nutrient Tank	2024	12,575 gallons	N/A

Tank #65	Tank #65	Bioreactor Hydrochloric Acid Tank	2024	6,000 gallons	N/A
Tank #66	Tank #66	WW Pond Sulfuric Acid Tank	2023	14,500 gallons	N/A
Tank #67	Tank #67	WW Pond Sodium Hydroxide Tank	2023	20,300 gallons	N/A
Tank #68	Tank #68	WW Pond Organosulfide Tank	2023	6,400 gallons	N/A
Tank #69	Tank #69	WW Pond Polymer Tank	2023	1,360 gallons	N/A

"Year Installed" reflects the "commenced" construction or modification date as defined in 40 C.F.R. Part 60.

[2] Rated Design Capacity

[3] Control Device/Control System abbreviations: ESP = Electrostatic Precipitators, LNB = Low NOx Burners, SCR = Selective Catalytic Reduction, FGD = Flue Gas Desulfurization, FE = Full enclosure, PE = Partial Enclosure, BH = Baghouse(s), MC = Moisture Content, WS = Wetting Spray, TC = Telescopic Chute, BVF = Bin Vent Filter, TS = Vacuum/Pressure Transfer Stations, N/A = Not applicable

1.2. Active R13, R14, and R19 Permits

The underlying authority for any conditions from R13, R14, and/or R19 permits contained in this operating permit is cited using the original permit number (e.g. R13-1234). The current applicable version of such permit(s) is listed below.

Permit Number	Date of Issuance
R13-2608E	May ~~8~~12, 2014
G60-C057A	August 8, 2014
~~Phase II Acid Rain Permit # R33-3948-2027-6~~	~~December 19, 2022~~

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 other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.39.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.1.4. Unless otherwise specified in a permit condition or underlying rule or regulation, all references to a "rolling yearly total" shall mean the sum of the monthly data, values or parameters being measured, monitored, or recorded, at any given time for the previous twelve (12) consecutive calendar months.

2.2. Acronyms

CAAA	Clean Air Act Amendments
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
C.F.R. ***or*** **CFR**	Code of Federal Regulations
CO	Carbon Monoxide
C.S.R. ***or*** **CSR**	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
FOIA	Freedom of Information Act
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr ***or*** **lb/hr**	Pounds per Hour
LDAR	Leak Detection and Repair
m	Thousand
MACT	Maximum Achievable Control Technology
mm	Million
mmBtu/hr	Million British Thermal Units per Hour
mmft³/hr ***or*** **mmcf/hr**	Million Cubic Feet Burned per Hour
NA ***or*** **N/A**	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10μm in diameter
pph	Pounds per Hour
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
VOC	Volatile Organic Compounds

2.3. Permit Expiration and Renewal

2.3.1. Permit duration. This permit is issued for a fixed term of five (5) years and shall expire on the date specified on the cover of this permit, except as provided in 45CSR§30-6.3.b. and 45CSR§30-6.3.c.
[45CSR§30-5.1.b.]

2.3.2. A permit renewal application is timely if it is submitted at least six (6) months prior to the date of permit expiration.
[45CSR§30-4.1.a.3.]

2.3.3. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with 45CSR§30-6.2. and 45CSR§30-4.1.a.3.
[45CSR§30-6.3.b.]

2.3.4. If the Secretary fails to take final action to deny or approve a timely and complete permit application before the end of the term of the previous permit, the permit shall not expire until the renewal permit has been issued or denied, and any permit shield granted for the permit shall continue in effect during that time.
[45CSR§30-6.3.c.]

2.4. Permit Actions

2.4.1. This permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
[45CSR§30-5.1.f.3.]

2.5. Reopening for Cause

2.5.1. This permit shall be reopened and revised under any of the following circumstances:

a. Additional applicable requirements under the Clean Air Act or the Secretary's legislative rules become applicable to a major source with a remaining permit term of three (3) or more years. Such a reopening shall be completed not later than eighteen (18) months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 45CSR§§30-6.6.a.1.A. or B.

b. Additional requirements (including excess emissions requirements) become applicable to an affected source under Title IV of the Clean Air Act (Acid Deposition Control) or other legislative rules of the Secretary. Upon approval by U.S. EPA, excess emissions offset plans shall be incorporated into the permit.

c. The Secretary or U.S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

d. The Secretary or U.S. EPA determines that the permit must be revised or revoked and reissued to assure compliance with the applicable requirements.

[45CSR§30-6.6.a.]

2.6. Administrative Permit Amendments

2.6.1. The permittee may request an administrative permit amendment as defined in and according to the procedures specified in 45CSR§30-6.4.
[45CSR§30-6.4.]

2.7. Minor Permit Modifications

2.7.1. The permittee may request a minor permit modification as defined in and according to the procedures specified in 45CSR§30-6.5.a.
[45CSR§30-6.5.a.]

2.8. Significant Permit Modification

2.8.1. The permittee may request a significant permit modification, in accordance with 45CSR§30-6.5.b., for permit modifications that do not qualify for minor permit modifications or as administrative amendments.
[45CSR§30-6.5.b.]

2.9. Emissions Trading

2.9.1. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit and that are in accordance with all applicable requirements.
[45CSR§30-5.1.h.]

2.10. Off-Permit Changes

2.10.1. Except as provided below, a facility may make any change in its operations or emissions that is not addressed nor prohibited in its permit and which is not considered to be construction nor modification under any rule promulgated by the Secretary without obtaining an amendment or modification of its permit. Such changes shall be subject to the following requirements and restrictions:

a. The change must meet all applicable requirements and may not violate any existing permit term or condition.

b. The permittee must provide a written notice of the change to the Secretary and to U.S. EPA within two (2) business days following the date of the change. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the permit shield.

d. The permittee shall keep records describing all changes made at the source that result in emissions of regulated air pollutants, but not otherwise regulated under the permit, and the emissions resulting from those changes.

e. No permittee may make any change subject to any requirement under Title IV of the Clean Air Act (Acid Deposition Control) pursuant to the provisions of 45CSR§30-5.9.

f. No permittee may make any changes which would require preconstruction review under any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) pursuant to the provisions of 45CSR§30-5.9.

[45CSR§30-5.9.]

2.11. Operational Flexibility

2.11.1. The permittee may make changes within the facility as provided by § 502(b)(10) of the Clean Air Act. Such operational flexibility shall be provided in the permit in conformance with the permit application and applicable requirements. No such changes shall be a modification under any rule or any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) promulgated by the Secretary in accordance with Title I of the Clean Air Act and the change shall not result in a level of emissions exceeding the emissions allowable under the permit.
[45CSR§30-5.8]

2.11.2. Before making a change under 45CSR§30-5.8., the permittee shall provide advance written notice to the Secretary and to U.S. EPA, describing the change to be made, the date on which the change will occur, any changes in emissions, and any permit terms and conditions that are affected. The permittee shall thereafter maintain a copy of the notice with the permit, and the Secretary shall place a copy with the permit in the public file. The written notice shall be provided to the Secretary and U.S. EPA at least seven (7) days prior to the date that the change is to be made, except that this period may be shortened or eliminated as necessary for a change that must be implemented more quickly to address unanticipated conditions posing a significant health, safety, or environmental hazard. If less than seven (7) days notice is provided because of a need to respond more quickly to such unanticipated conditions, the permittee shall provide notice to the Secretary and U.S. EPA as soon as possible after learning of the need to make the change.
[45CSR§30-5.8.a.]

2.11.3. The permit shield shall not apply to changes made under 45CSR§30-5.8., except those provided for in 45CSR§30-5.8.d. However, the protection of the permit shield will continue to apply to operations and emissions that are not affected by the change, provided that the permittee complies with the terms and conditions of the permit applicable to such operations and emissions. The permit shield may be reinstated for emissions and operations affected by the change:

a. If subsequent changes cause the facility's operations and emissions to revert to those authorized in the permit and the permittee resumes compliance with the terms and conditions of the permit, or

b. If the permittee obtains final approval of a significant modification to the permit to incorporate the change in the permit.

[45CSR§30-5.8.c.]

2.11.4. "Section 502(b)(10) changes" are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.
[45CSR§30-2.40]

2.12. Reasonably Anticipated Operating Scenarios

2.12.1. The following are terms and conditions for reasonably anticipated operating scenarios identified in this permit.

a. Contemporaneously with making a change from one operating scenario to another, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating and to document the change in reports submitted pursuant to the terms of this permit and 45CSR30.

b. The permit shield shall extend to all terms and conditions under each such operating scenario; and

c. The terms and conditions of each such alternative scenario shall meet all applicable requirements and the requirements of 45CSR30.

[45CSR§30-5.1.i.]

2.13. Duty to Comply

2.13.1. 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; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.
[45CSR§30-5.1.f.1.]

2.14. Inspection and Entry

2.14.1. 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;

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.

[45CSR§30-5.3.b.]

2.15. Schedule of Compliance

2.15.1. For sources subject to a compliance schedule, certified progress reports shall be submitted consistent with the applicable schedule of compliance set forth in this permit and 45CSR§30-4.3.h., but at least every six (6) months, and no greater than once a month, and shall include the following:

a. Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when such activities, milestones or compliance were achieved; and

b. An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measure adopted.

[45CSR§30-5.3.d.]

2.16. Need to Halt or Reduce Activity not a Defense

2.16.1. It shall not be a defense for a permittee in an enforcement action that it would 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.
[45CSR§30-5.1.f.2.]

2.17. Reserved

2.18. Federally-Enforceable Requirements

2.18.1. All terms and conditions in this permit, including any provisions designed to limit a source's potential to emit and excepting those provisions that are specifically designated in the permit as "State-enforceable only", are enforceable by the Secretary, USEPA, and citizens under the Clean Air Act.
[45CSR§30-5.2.a.]

2.18.2. Those provisions specifically designated in the permit as “State-enforceable only” shall become “Federally-enforceable” requirements upon SIP approval by the USEPA.

2.19. Duty to Provide Information

2.19.1. 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 modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records required 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.
[45CSR§30-5.1.f.5.]

2.20. Duty to Supplement and Correct Information

2.20.1. 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.
[45CSR§30-4.2.]

2.21. Permit Shield

2.21.1. Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance provided that such applicable requirements are included and are specifically identified in this permit or the Secretary has determined that other requirements specifically identified are not applicable to the source and this permit includes such a determination or a concise summary thereof.
[45CSR§30-5.6.a.]

2.21.2. Nothing in this permit shall alter or affect the following:

a. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance; or

b. The applicable requirements of the Code of West Virginia and Title IV of the Clean Air Act (Acid Deposition Control), consistent with § 408 (a) of the Clean Air Act.

c. The authority of the Administrator of U.S. EPA to require information under § 114 of the Clean Air Act or to issue emergency orders under § 303 of the Clean Air Act.

[45CSR§305.6.c.]

2.22. Credible Evidence

2.22.1. 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 defenses otherwise available to the permittee including but not limited to any challenge to the credible evidence rule in the context of any future proceeding.
[45CSR§30-5.3.e.3.B.]

2.23. Severability

2.23.1. The provisions of this permit are severable. If any provision of this permit, or the application of any provision of this permit to any circumstance is held invalid by a court of competent jurisdiction, the remaining permit terms and conditions or their application to other circumstances shall remain in full force and effect.
[45CSR§305.1.e.]

2.24. Property Rights

2.24.1. This permit does not convey any property rights of any sort or any exclusive privilege.
[45CSR§30-5.1.f.4]

2.25. Acid Deposition Control

2.25.1. Emissions shall not exceed any allowances that the source lawfully holds under Title IV of the Clean Air Act (Acid Deposition Control) or rules of the Secretary promulgated thereunder.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid deposition control program, provided that such increases do not require a permit revision under any other applicable requirement.

b. No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

c. Any such allowance shall be accounted for according to the procedures established in rules promulgated under Title IV of the Clean Air Act.

[45CSR§30-5.1.d.]

2.25.2. Where applicable requirements of the Clean Air Act are more stringent than any applicable requirement of regulations promulgated under Title IV of the Clean Air Act (Acid Deposition Control), both provisions shall be incorporated into the permit and shall be enforceable by the Secretary and U. S. EPA.
[45CSR§30-5.1.a.2.]

3.0 Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person 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 or allow 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.
[40 C.F.R. §61.145(b) and 45CSR34]

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. **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]

3.1.6. **Emission inventory.** The permittee is responsible for submitting, on an annual basis, an emission inventory in accordance with the submittal requirements of the Division of Air Quality.
[W.Va. Code § 22-5-4(a)(15)]

3.1.7. **Ozone-depleting substances.** For those facilities performing maintenance, service, repair or disposal of appliances, the permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 C.F.R. Part 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the prohibitions and required practices pursuant to 40 C.F.R. §§ 82.154 and 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 C.F.R. § 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 C.F.R. § 82.161.

[40 C.F.R. 82, Subpart F]

3.1.8. **Risk Management Plan.** Should this stationary source, as defined in 40 C.F.R. § 68.3, become subject to Part 68, then the owner or operator shall submit a risk management plan (RMP) by the date specified in 40 C.F.R. § 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 C.F.R. Part 70 or 71.
[40 C.F.R. 68]

3.1.9. **Fugitive Particulate Matter Control.** No person shall cause, suffer, allow, or permit any source of fugitive particulate matter to operate that is not equipped with a fugitive particulate matter control system. This system shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter. Sources of fugitive particulate matter associated with fuel burning units shall include, but not be limited to, the following:

a. Stockpiling of ash or fuel either in the open or in enclosures such as silos;

b. Transport of ash in vehicles or on conveying systems, to include spillage, tracking, or blowing of particulate matter from or by such vehicles or equipment; and

c. Ash or fuel handling systems and ash disposal areas.

d. Flue Gas Desulfurization (FGD) and Selective Catalytic Reduction (SCR) material handling systems.

[45CSR§2-5; 45CSR13, R13-2608, 4.1.18.]

3.1.10. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed within Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S, and emission unit Aux 1 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.
[45CSR13, R13-2608, 4.1.25. and 5.1.2; 45CSR§13-5.11.]

3.1.11. **40 C.F.R. Part 97, Subpart AAAAA – CSAPR NO_x Annual Trading Program.** The permittee shall comply with the standard requirements set forth in the attached Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements (see APPENDIX E).
[40 C.F.R. § 97.406; 45CSR43]

3.1.12. **40 C.F.R. Part 97, Subpart EEEEE – CSAPR NO_x Ozone Season Group 2 Trading Program.** The permittee shall comply with the standard requirements set forth in the attached Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements (see APPENDIX E).
[40 C.F.R. § 97.806; 45CSR43]

3.1.13. **40 C.F.R. Part 97, Subpart CCCCC – CSAPR SO_2 Group 1 Trading Program.** The permittee shall comply with the standard requirements set forth in the attached Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements (see APPENDIX E).
[40 C.F.R. § 97.606; 45CSR43]

3.2. Monitoring Requirements

3.2.1. 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 sourcespecific 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, if applicable, in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable.

b. The Secretary may on a sourcespecific 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 shall be revised in accordance with 45CSR§30-6.4 or 45CSR§30-6.5 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 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.

3. A statement of compliance or non-compliance with each permit or rule condition.

[WV Code §§ 2254(a)(15-16) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Monitoring information.** 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.

[45CSR§30-5.1.c.2.A.]
[45CSR13, R13-2608, 4.4.1.] (Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S)
[45CSR13, R13-2608, 5.4.1.] (Em. Unit ID: Aux 1)

3.4.2. **Retention of records.** The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of monitoring sample, measurement, report, application, or record creation date. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Where appropriate, records may be maintained in computerized form in lieu of the above records.
[45CSR§30-5.1.c.2.B.]

3.4.3. **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§30-5.1.c. State-Enforceable only.]

3.4.4. The permittee shall maintain records indicating the use of any dust suppressants or any other suitable dust control measures applied at the facility. The permittee shall also inspect all fugitive dust control systems weekly from May 1 through September 30 and monthly from October 1 through April 30 to ensure that they are operated as necessary and maintained in good working order. The permittee shall maintain records of all scheduled and non-scheduled maintenance and shall state any maintenance or corrective actions taken as a result of the weekly and/or monthly inspections, the times the fugitive dust control system(s) were inoperable and any corrective actions taken.
[45CSR§30-5.1.c.]

3.4.5. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed within Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S in Section 1.0 and control equipment for the Auxiliary Boiler (Aux 1), the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.
[45CSR13, R13-2608, 4.4.2. and 5.4.2.]

3.4.6. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed within Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S in Section 1.0 and control equipment for the Auxiliary Boiler (Aux 1), 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.

[45CSR13, R13-2608, 4.4.3. and 5.4.3.]

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.
[45CSR§§30-4.4. *and* 5.1.c.3.D.]

3.5.2. A permittee may request confidential treatment for the submission of reporting required under 45CSR§30-5.1.c.3. pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.
[45CSR§30-5.1.c.3.E.]

3.5.3. Except for the electronic submittal of the annual compliance certification and semi-annual monitoring reports to the DAQ and USEPA as required in 3.5.5 and 3.5.6 below, 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 or by private carrier with postage prepaid to the address(es), or submitted in electronic format by e-mail as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ:	**US EPA:**
Director WVDEP Division of Air Quality 601 57th Street SE Charleston, WV 25304	Section Chief U. S. Environmental Protection Agency, Region III Enforcement and Compliance Assurance Division Air, RCRA and Toxics Branch (3ED21) Four Penn Center 1600 John F. Kennedy Boulevard Philadelphia, PA 19103-2852

DAQ Compliance and Enforcement[1]:
DEPAirQualityReports@wv.gov

[1]For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status reports, Initial Notifications, etc.

3.5.4. **Fees.** The permittee shall pay fees on an annual basis in accordance with 45CSR§30-8.
[45CSR§30-8.]

3.5.5. **Compliance certification.** The permittee shall certify compliance with the conditions of this permit on the forms provided by the DAQ. In addition to the annual compliance certification, the permittee may be required to submit certifications more frequently under an applicable requirement of this permit. The annual certification shall be submitted to the DAQ and USEPA on or before March 15 of each year, and shall certify compliance for the period ending December 31. The permittee shall maintain a copy of the certification on site for five (5) years from submittal of the certification. The annual certification shall be submitted in electronic format by e-mail to the following addresses:

DAQ:	**US EPA:**
DEPAirQualityReports@wv.gov	R3_APD_Permits@epa.gov

[45CSR§30-5.3.e.]

3.5.6. **Semi-annual monitoring reports.** The permittee shall submit reports of any required monitoring on or before September 15 for the reporting period January 1 to June 30 and on or before March 15 for the reporting period July 1 to December 31. All instances of deviation from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with 45CSR§30-4.4. The semi-annual monitoring reports shall be submitted in electronic format by e-mail to the following address:

DAQ:
DEPAirQualityReports@wv.gov

[45CSR§30-5.1.c.3.A.]

3.5.7. **Reserved.**

3.5.8. **Deviations.**

a. In addition to monitoring reports required by this permit, the permittee shall promptly submit supplemental reports and notices in accordance with the following:

1. Reserved.

2. Any deviation that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to the Secretary immediately by telephone or email. A written report of such deviation, which shall include the probable cause of such deviation, and any corrective actions or preventative measures taken, shall be submitted by the responsible official within ten (10) days of the deviation.

3. Deviations for which more frequent reporting is required under this permit shall be reported on the more frequent basis.

4. All reports of deviations shall identify the probable cause of the deviation and any corrective actions or preventative measures taken.

[45CSR§30-5.1.c.3.C.]

b. The permittee shall, in the reporting of deviations from permit requirements, including those attributable to upset conditions as defined in this permit, report the probable cause of such deviations and any corrective actions or preventive measures taken in accordance with any rules of the Secretary.
[45CSR§30-5.1.c.3.B.]

3.5.9. **New applicable requirements.** If any applicable requirement is promulgated during the term of this permit, the permittee will meet such requirements on a timely basis, or in accordance with a more detailed schedule if required by the applicable requirement.
[45CSR§30-4.3.h.1.B.]

3.6. Compliance Plan

3.6.1. There is no compliance plan since a responsible official certified compliance with all applicable requirements in the Title V renewal application.

3.7. Permit Shield

3.7.1. The permittee is hereby granted a permit shield in accordance with 45CSR§30-5.6. The permit shield applies provided the permittee operates in accordance with the information contained within this permit.

3.7.2. The following requirements specifically identified are not applicable to the source based on the determinations set forth below. The permit shield shall apply to the following requirements provided the conditions of the determinations are met.

a. **45CSR5 – *To Prevent and Control Air Pollution from the Operation of Coal Preparation Plants, Coal Handling Operations and Coal Refuse Disposal Areas***. Since the facility is subject to 45CSR2, according to 45CSR§5-~~2.4.b~~2.5. the facility is not included in the definition of a "Coal Preparation Plant". Therefore, 45CSR5 does not apply to the facility, and particularly to its coal crushing operations and associated coal handling.

b. **45CSR7 – *To Prevent and Control Particulate Matter Air Pollution from Manufacturing Processes and Associated Operations.*** Since the facility is subject to 45CSR2, 45CSR§7-10.1. provides an exemption from 45CSR7.

c. **45CSR17 – *To Prevent and Control Particulate Matter Air Pollution from Material Handling, Preparation, Storage and Other Sources of Fugitive Particulate Matter.*** The facility is characterized by the handling and storage of materials that have the potential to produce fugitive particulate if not properly controlled. However, since the facility is subject to 45CSR2, it is not subject to this rule in accordance with the exemption granted in 45CSR§17-6.1.

d. **40 C.F.R. 60 Subpart D – *Standards of Performance for Fossil-fuel-fired Steam Generators for which Construction is Commenced after August 17, 1971.*** The fossil-fuel-fired steam generators potentially affected by this rule have not commenced construction or modification after August 17, 1971. Therefore, the units do not meet the applicability criteria under §60.40(c), and hence the NSPS does not apply.

e. **40 C.F.R. 60 Subpart Da – *Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978.*** The electric utility steam generating units (i.e., Unit 1 and Unit 2) potentially affected by this rule have not commenced construction or modification after September 18, 1978. Therefore, the units do not meet the applicability criteria under §60.40Da(a)(2), and hence the NSPS does not apply to Unit 1 and Unit 2. The auxiliary boiler (Aux 1) was not constructed or reconstructed "for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale." As such, Aux 1 does not meet the definition of an *Electric utility steam-generating unit* in §60.41Da, and therefore, does not meet the applicability criteria of §60.40Da(a). Consequently, NSPS Subpart Da does not apply to Aux 1.

f. **40 C.F.R. 60 Subpart K - *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R. §60.111(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after June 11, 1973 and prior to May 19, 1978. Therefore, the tanks do not meet the applicability criteria under §60.110, and hence the NSPS does not apply.

g. **40 C.F.R. 60 Subpart Ka - *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R. §60.111a(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after May 18, 1978 and prior to July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110a(a), and hence the NSPS does not apply.

h. **40 C.F.R. 60 Subpart Kb - *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 and On or Before October 4, 2023*.** Storage vessels potentially affected by this rule are exempted because they contain liquids with a maximum true vapor pressure of less than 3.5 kPa, have a storage capacity of less than 75 cubic meters, or have not commenced construction, reconstruction or modification after July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110b, and hence the NSPS does not apply.

i. **40 C.F.R. 60 Subpart Y – *Standards of Performance for Coal Preparation Plants.*** The coal handling equipment potentially affected by this rule has not been constructed or modified after October 24, 1974. Therefore, the equipment does not meet the applicability criteria set forth in 40 C.F.R. §60.250(b), and hence this NSPS does not apply.

j. **40 C.F.R. 63 Subpart Q – *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers.*** This facility does not include *industrial process cooling towers* that have operated with chromium-based water treatment chemicals. Therefore, the facility does not meet the applicability criteria set forth in §63.400(a), and hence this MACT does not apply to the facility.

4.0 Main Boilers [Emission Unit IDs *Unit 1* and *Unit 2* – Emission Point IDs *1E* and *2E*]

4.0.1. **~~Emergency Operating Scenarios~~Reserved**

~~a. In the event of an unavoidable shortage of fuel having characteristics or specifications necessary to comply with the visible emission requirements or any emergency situation or condition creating a threat to public safety or welfare, the Secretary may grant an exemption to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during that period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the weight emission requirements will not be exceeded during the exemption period.~~
~~[45CSR§2-10.1.]~~

~~b. Due to unavoidable malfunction of equipment or inadvertent fuel shortages, SO_2 emissions from the main boilers exceeding those provided for in 45CSR§§10-3.1.b. and 3.1.e., respectively, may be permitted by the Secretary for periods not to exceed ten (10) days upon specific application to the Secretary. Such application shall be made within twenty-four (24) hours of the equipment malfunction or fuel shortage. In cases of major equipment failure or extended shortages of conforming fuels, additional time periods may be granted by the Secretary, provided a corrective program has been submitted by the owner or operator and approved by the Secretary.~~
~~[45CSR§10-9.1.]~~

4.0.2. **Thermal Decomposition of Boiler Cleaning Solutions.** The thermal decomposition of boiler cleaning solutions is permitted upon notification to the Secretary, provided that records are maintained which show that the solutions are non-hazardous materials and that the combustion of such solutions does not produce hazardous compounds or emissions. Such records shall be kept on site for a period of no less than five (5) years and shall be made available, in a suitable form for inspection, to the Secretary upon request. See Appendix C.
[WVDAQ Letter dated September 3, 2002 addressed to Mr. Greg Wooten and signed by Jesse D. Adkins - State-Enforceable only]

4.0.3. **Combustion of Demineralizer Resins.** The combustion of demineralizer resins is permitted in accordance with the WVDAQ letter dated January 21, 2004 addressed to Mr. Frank Blake and signed by Jesse D. Adkins and subject to the DAQ notification requirements as outlined in the document titled "American Electric Power Demineralizer Resin Burn Notification Procedure." Records pertaining to the combustion of demineralizer resins shall be kept in accordance with 3.3.2. and shall be made available, in a suitable form for inspection, to the Secretary upon request. See Appendix D.
[WVDAQ Letter dated January 21, 2004 addressed to Mr. Frank Blake and signed by Jesse D. Adkins - State-Enforceable only; 45CSR§30-5.1.c.]

4.1. Limitations and Standards

4.1.1. Any fuel burning unit(s) including associated air pollution control equipment, shall at all times, including periods of start-up, shutdowns, and malfunctions, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions.
[45CSR§2-9.2.]

4.1.2. Visible Emissions from Unit 1 & 2 stacks shall not exceed ten (10) percent opacity based on a six minute block average.
[45CSR§2-3.1.]

4.1.3. ~~The visible emission standards (condition 4.1.2.) shall apply at all times except in periods of start ups, shutdowns and malfunctions.~~Reserved.
~~**[45CSR§2-9.1.]**~~

4.1.4. a. Particulate matter emissions from Unit 1 & 2 stacks shall not exceed 702 lb/hr. The averaging time shall be the arithmetic average of three (3) complete sampling runs consisting of a minimum total sampling time of two (2) hours per run.
[45CSR§2-4.1.~~a~~1.; 45CSR2-Appendix §§ 4.1.b. & 4.1.c.]

b. **Filterable Particulate Matter (PM) Emission Limitation for 40 C.F.R. 63 Subpart UUUUU.** Before July 6, 2027, ~~If~~ if your EGU is in the coal-fired unit not low rank virgin coal subcategory, for filterable particulate matter (PM), you must meet the emission limit 0.030 lb/MMBtu or 0.30 lb/MWh, by collecting a minimum of 1 dscm per run according to applicable test methods in Table 5 to Subpart UUUUU. On or after July 6, 2027, you must meet the emission limit 0.010 lb/MMBtu or 0.10 lb/MWh (gross output), by collecting a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run according to the applicable test methods in Table 5 to Subpart UUUUU. For LEE emissions testing for total PM, the required minimum sampling volume must be increased nominally by a factor of two. On or after July 6, 2027, you may not pursue the LEE option for filterable PM and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits unless you request and receive approval for the use of a HAP metals CMS under 40 C.F.R. §63.7(f).
[40 C.F.R. §63.9991(a)(1), Table 2, Item #1.a.; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.5. a. Sulfur dioxide emissions from Unit 1 and Unit 2 stacks (Em. Pt. IDs: 1E, 2E) shall not exceed a heat input weighted average of 1.2 lb/mmBtu SO_2 on a 3-hour block average basis, with SO_2 mass emissions not to exceed an average of 20,485.2 lb SO_2/hr on a 3-hour block average basis. *Compliance with this limitation will assure compliance with the 45CSR10 limitation of 7.5 lb/mmBtu.*
[45CSR§30-12.7.; 45CSR§§10-3.1., and 3.1.~~b~~2.]

b. **Sulfur Dioxide (SO_2) Emission Limitation for 40 C.F.R. 63 Subpart UUUUU.** If your EGU is in the coal-fired unit not low rank virgin coal subcategory, for sulfur dioxide (SO_2), you must meet the emission limit 0.20 lb/MMBtu, using SO_2 CEMS according to applicable methods in Table 5 and procedures in Table 7 to 40 C.F.R. 63 Subpart UUUUU.

You may use the alternate SO_2 limit in Table 2 to 40 C.F.R. 63 Subpart UUUUU only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and 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 40 C.F.R. §63.10000(b) (permit condition 4.1.12.).

[40 C.F.R. §63.9991(a)(1), Table 2, Item #1.b.; 40 C.F.R. §63.10000(a); 40 C.F.R. §§63.9991(c)(1) and (2); 45CSR34]

4.1.6. Compliance with the allowable sulfur dioxide emission limitations from the Unit 1 & 2 boilers in condition 4.1.5.a. shall be based on a continuous twenty-four (24) hour averaging time. Emissions shall not be

allowed to exceed the weight emissions standards for sulfur dioxide as set forth in 45CSR10, except during one (1) continuous twenty-four (24) hour period in each calendar month. During this one (1) continuous twenty-four hour period, emissions shall not be allowed to exceed such weight emission standards by more than ten percent (10%) without causing a violation of 45CSR10. A continuous twenty-four (24) hour period is defined as one (1) calendar day.
[45CSR§10-3.8.]

4.1.7. **Dry Sorbent Injection.** The permittee shall operate the SO_3 dry-sorbent injection control system consistent with the technological capabilities and limitations of the system and with good operation and maintenance practices whenever *Unit 1* or *Unit 2* (or both) is operating, except during periods of startup, shut-down, malfunction, and maintenance.
[45CSR§30-12.7., State-enforceable only]

4.1.8. **Mercury (Hg) Emission Limitation for 40 C.F.R. 63 Subpart UUUUU.** If your EGU is in the coal-fired unit not low rank virgin coal subcategory, for mercury (Hg), you must meet the emission limit 1.2 lb/TBtu, or 0.013 lb/GWh using either of the following:

(1) LEE testing for 30 days per Table 2 to Subpart UUUUU using applicable methods in Table 5 to Subpart UUUUU, or

(2) Hg CEMS or sorbent trap monitoring system only, using applicable methods in Table 5 to Subpart UUUUU.

[40 C.F.R. §63.9991(a)(1), Table 2, Item #1.c.; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.9. **Tune-up Work Practice Standard for 40 C.F.R. 63 Subpart UUUUU**. If your EGU is an existing EGU, you must conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in 40 C.F.R. §63.10021(e).

Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (1) through (9) of this condition. 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. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

(1) 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;

(2) 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;

(3) 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;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) 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;

(6) 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;

(7) 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 continual values before and after each optimization adjustment made by the system.

(8) You must maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (1) through (9) of 40 C.F.R. §§63.10021(e) (permit condition 4.1.9.) including:

(i) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period.

(9) Report the ~~dates of the initial and subsequent tune-ups in hard copy, as specified in §63.10031(f)(5), through June 30, 2020. On or after July 1, 2020, report the date of all tune-ups~~tune-up date electronically in your quarterly compliance report, in accordance with §63.10031(~~f~~g) and section 10.2 of appendix E to this subpart. The tune-up report date is the date when tune-up requirements in paragraphs (6) and (7) of this condition are completed.

[40 C.F.R. §63.9991(a)(1), Table 3, Item #1; 40 C.F.R. §§63.10021(e)(1) through (9); 40 C.F.R. §63.10021(a), Table 7, Item #5; 40 C.F.R. §63.10000(e); 40 C.F.R. §63.10006(i)(1); 45CSR34]

4.1.10. **Startup Work Practice Standard for 40 C.F.R. 63 Subpart UUUUU.**

a. (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 §§63.10021(h) and (i) (permit conditions 4.1.14. and 4.5.10.a.(1)).

c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.

d. You must collect monitoring data during startup periods, as specified in §63.10020(a) (permit conditions 4.2.13., 4.2.14., and 4.2.15.). You must keep records during startup periods, as provided in §§63.10032 and 63.10021(h) (permit conditions 4.4.6. through 4.4.13., and 4.1.14.). You must provide reports concerning activities and startup periods, as specified in §§63.10021(i) (permit condition 4.5.10.a.(1)), and 63.10031 (permit condition 4.5.10.).

[40 C.F.R. §63.9991(a)(1), Table 3, Items 3.a.(1), 3.c., 3.d.; 40 C.F.R. §63.10021(a), Table 7, Item #6; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.11. **Shutdown Work Practice Standard for 40 C.F.R. 63 Subpart UUUUU.** 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 for those pollutants for which a CMS is used.

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 possible, taking into account considerations such as not compromising boiler or control device integrity.

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 §§63.10021(i), and 63.10031.

[40 C.F.R. §63.9991(a)(1), Table 3, Item #4; 40 C.F.R. §63.10021(a), Table 7, Item #7; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.12. At all times you must operate and maintain any affected source, 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 EPA Administrator 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 C.F.R. §63.10000(b); 45CSR34]

4.1.13. Fuel Requirements for startup and shutdown.

(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

[40 C.F.R. §63.10011(f); 45CSR34]

4.1.14. You must follow the startup or shutdown requirements as given in Table 3 to 40 C.F.R. 63 Subpart UUUUU for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in §63.10007(f) (permit condition 4.2.16.), 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 (permit conditions 4.5.10., 4.5.11., 4.5.12., and 4.5.13.).~~

[40 C.F.R. §§63.10021(h), (h)(1), and (2); 45CSR34]

4.1.15. **Selective Catalytic Reactors and Flue Gas Desulfurization**.

(1) On and after January 1, 2009, install and continuously operate Selective Catalytic reactors (SCRs) on Mitchell Units 1 and 2.

(2) On and after December 31, 2007, install and continuously operate Flue Gas Desulfurization (FGD) on Mitchell Units 1 and 2.

(3) Pursuant to the consent decree, “continuously operate” means that when the SCR and/or FGD is used at a unit, except during a “malfunction,” the FGD and/or SCR shall be operated at all times the unit is in operation, consistent with the technological limitations, manufacturer’s specifications, and good engineering and maintenance practices for the control equipment and the unit so as to minimize emissions to the greatest extent practicable.

(4) Pursuant to the consent decree, a “malfunction” means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(5) On and after December 31, 2012, install, calibrate, operate, and maintain PM CEMS on Mitchell Unit 2, and maintain in an electronic database the hourly average emission values in lbs/mmBtu. The permittee shall use reasonable efforts to keep the PM CEMS running and producing data whenever Unit 2 is operating. Data from the PM CEMS shall be used, at a minimum, to monitor progress in reducing PM emissions, but stack testing according to reference methods approved by the Administrator shall be used to determine compliance with any PM emission rate applicable to Unit 2.

[45CSR§30-12.7]

4.2. Monitoring Requirements

4.2.1. Compliance with the visible emission requirements for emission points *1E* and *2E* shall be determined as outlined in section I.A.2. of the DAQ approved “45CSR2 Monitoring Plan” attached in Appendix A of this permit.
[45CSR§§2-3.2., 8.1.~~a~~ 1 & 8.2., 45CSR§2A-6]

4.2.2. The owner or operator shall install, calibrate, certify, operate, and maintain continuous monitoring systems that measure opacity and all SO_2, and NO_x, emissions from emission points *1E* and *2E* as specified in 40 C.F.R. Part 75 and measure CO_2 emissions from emission points *1E* and *2E* as specified in 40 C.F.R. Part 75. Refer to permit condition 4.1.5.b. for the 40 C.F.R. 63 Subpart UUUUU SO_2 alternate limit for acid gases, and corresponding monitoring requirements in conditions 4.2.18. through 4.2.21.
[45CSR33; 40 C.F.R. §75.10; 40 C.F.R. §§ 64.3(b)(1) and 64.3(b)(4)(ii); 45CSR§30-5.1.c.]

4.2.3. Compliance with the operating and fuel usage requirements for Units 1 & 2 shall be demonstrated as outlined in section I.A.3. of the DAQ approved “45CSR2 Monitoring Plan” attached in Appendix A of this permit.
[45CSR§§2-8.3.~~c~~3., 8.4.~~a~~1. & 8.4.~~a~~1.~~1~~a.]

4.2.4. The owner or operator shall implement a Compliance Assurance Monitoring (CAM) program in accordance with the following:

(a) The permittee shall monitor and maintain 6-minute opacity averages measured by a continuous opacity monitoring system, operated and maintained pursuant to 40 C.F.R. Part 75, including the minimum data requirements, in order to determine 3-hour block average opacity values. The permittee may also use COMS that satisfy Section 51.214 and appendix P of Part 51, or Section 60.13 and appendix B of Part 60, to satisfy the general design criteria under 40 C.F.R. §§64.3(a) and (b).
[45CSR§30-5.1.c. and 40 C.F.R. § 64.6(c)(1)(i) and (ii)]

(b) The COM QA/QC procedures shall be equivalent to the applicable requirements of 40 C.F.R. Part 75. The permittee may also use COMS that satisfy Section 51.214 and appendix P of Part 51, or Section 60.13 and appendix B of Part 60, to satisfy the general design criteria under 40 C.F.R. §§64.3(a) and (b).
[40 C.F.R. §75.21 and 40 C.F.R. § 64.6(c)(iii)]

(c) The 6-minute opacity averages from permit condition 4.2.4.(a) shall be used to calculate 3-hour block average opacity values. Data recorded during monitoring malfunctions, associated repairs and QA/QC activities shall not be used for calculating the 3-hour averages. All other available qualified data consisting of 6-minute opacity averages will be used to calculate a 3-hour average. Data availability shall be at least of 50% of the operating time in the 3-hour block to satisfy the data requirements to calculate the 3-hour average opacity. However, the number of invalid 3-hour blocks shall not exceed 15% of the total 3-hour blocks during unit operation for a quarterly reporting period.

An excursion of the indicator range shall be defined as two consecutive 3-hour block average opacity values that exceed 10%.

[45CSR§30-5.1.c.; 40 C.F.R. §§ 64.6(c)(2) and (4) and 40 C.F.R. § 64.7(c)]

4.2.5. **Proper Maintenance** – At all times, the permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[40 C.F.R. § 64.7(b); 45CSR§30-5.1.c.]

4.2.6. **Response to Excursions or Exceedances**

(a) Upon detecting an excursion or exceedance, the permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable

(b) Determination of whether the permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 C.F.R. § 64.7(d); 45CSR§30-5.1.c.]

4.2.7. **Documentation of Need for Improved Monitoring** – After approval of monitoring under 40 C.F.R. Part 64, if the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the Director and, if necessary, submit a proposed modification to the permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[40 C.F.R. § 64.7(e); 45CSR§30-5.1.c.]

4.2.8. **Quality Improvement Plan (QIP)**

(1) Based on the results of a determination made under permit condition 4.2.6.(b) or 4.2.8.(2), the Administrator or the Director may require the permittee to develop and implement a QIP. If a QIP is required, then it shall be developed, implemented, and modified as required according to 40 C.F.R. §§ 64.8(b) through (e). Refer to permit condition 4.5.6.(b)(iii) for the reporting required when a QIP is implemented.

(2) If five (5) percent or greater of the three (3) hour average COMS opacity values, determined in accordance with 4.2.4.(c) of this permit, indicate excursions of the 10% opacity threshold during a calendar quarter, the permittee shall develop and implement a QIP. The Director may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to permit condition 3.2.1.

[40 C.F.R. §§ 64.8, and 64.7(d); 45CSR§30-5.1.c.]

4.2.9. **Continued Operation** – Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of 40 C.F.R. Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[40 C.F.R. § 64.7(c); 45CSR§30-5.1.c.]

4.2.10. The permittee shall perform daily monitoring and recordkeeping of the total daily dry sorbent usage rate (pounds /tons per day) and startups, shutdowns, malfunctions, and maintenance associated with the dry sorbent injection system.
[45CSR§30-5.1.c., State-enforceable only]

4.2.11. If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values in §63.10007(f) are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of 40 C.F.R. 63 Subpart UUUUU, these default values are not considered to be substitute data.

[40 C.F.R. §63.10007(f); 45CSR34] (*SO_2 CEMS; Hg sorbent trap monitoring system*)

4.2.12. *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS (which on or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit), and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 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. You 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.

If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

SO_2 CEMS Requirements for 40 C.F.R. 63 Subpart UUUUU.

(1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.
(2) 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 this chapter, with the following addition: You 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.
(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 30 boiler operating day period.
(4) 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 §63.10042) the default gross output and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO_2 emission rate for any of these hours.

If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You 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 the subpart, 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 this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

[40 C.F.R. §§63.10010(a)(1), (b), (c), (f), and (g); 40 C.F.R. §63.10021(a), Table 7, Item #1; 45CSR34]

4.2.13. You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for ~~periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), and~~ required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in your site-specific monitoring plan. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.
[40 C.F.R. §§63.10020(b) and (a); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.2.14. You may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 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. You 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 C.F.R. §§63.10020(c) and (a); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.2.15. ~~Except for p~~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~~ excluding zero and span ~~adjustments), failure~~checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements.
[40 C.F.R. §§63.10020(d) and (a); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.2.16. Except as otherwise provided in §63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in §63.10021(b) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.
[40 C.F.R. §63.10021(b); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.3. Testing Requirements

4.3.1. The owner or operator shall conduct, or have conducted, tests to determine the compliance of Unit 1 & Unit 2 with the particulate matter mass emission limitations. Such tests shall be conducted in accordance with the appropriate method set forth in 45CSR2 Appendix - Compliance Test Procedures for 45CSR2 or other equivalent EPA approved method approved by the Secretary. Such tests shall be conducted in accordance with the schedule set forth in the following table. The next testing shall be performed no later than December 13, 2021.

Test	Test Results	Retesting Frequency
Annual	after three successive tests indicate mass emission rates ≤50% of weight emission standard	Once/3 years [1]
Annual	after two successive tests indicate mass emission rates <80 % of weight emission standard	Once/2 years [2]
Annual	any test indicates a mass emission rate ≥80% of weight emission standard	Annual [3]
Once/2 years	after two successive tests indicate mass emission rates ≤50% of weight emission standard	Once/3 years
Once/2 years	any test indicates a mass emission rate <80 % of weight emission standard	Once/2 years
Once/2 years	any test indicates a mass emission rate ≥80% of weight emission standard	Annual
Once/3 years	any test indicates a mass emission rate ≤50% of weight emission standard	Once/3 years
Once/3 years	any test indicates mass emission rates between 50% and 80 % of weight emission standard	Once/2 years
Once/3 years	any test indicates a mass emission rate ≥80% of weight emission standard	Annual

1 Once/3 years is Cycle '3' and means that testing shall be performed within thirty-six (36) months from the date of the previous test, but no earlier than eighteen (18) months from the date of the previous test (see 45CSR§2A-2.6.c.).

2 Once/2 years is Cycle '2' and means that testing shall be performed within twenty-four (24) months from the date of the previous test, but no earlier than twelve (12) months from the date of the previous test (see 45CSR§2A-2.6.b.).

3 Annual is Cycle '1' and means that testing shall be performed within twelve (12) months from the date of the previous test, but no earlier than six (6) months from the date of the previous test (see 45CSR§2A-2.6.a.).

[45CSR§2-8.1., 45CSR§2A-5.2.]

4.3.2. Data collected during future periodic 45CSR2 mass emissions tests (under permit condition 4.3.1.) will be used to supplement the existing data set in order to verify the continuing appropriateness of the 10% indicator range value.
[45CSR§30-5.1.c. and 40 C.F.R. § 64.6(b)]

4.3.3. *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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM. You may pursue this compliance option unless prohibited pursuant to §63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h) with the exception that on or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for any existing, new or reconstructed EGUs (this does not apply to IGCC units), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in §63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in §63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(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- (or 90-) boiler operating day test period. You may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. 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.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from §75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly gross output data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m3 (dry basis), for each of LEE test runs comprising the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results from the LEE test period. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and gross output for the LEE test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in §63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(1) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^{-6} to convert it to TBtu/hr; or

(2) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^{-3} to convert it to GW; or

(3) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

[40 C.F.R. §63.10005(h); 45CSR34]

4.3.4. For affected units meeting the LEE requirements of §63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and §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:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1).

[40 C.F.R. §63.10006(b); 45CSR34]

4.3.5. *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, measured from the test's end date, must separate performance tests conducted every quarter;

(ii) For annual testing:

(A) At least 320 calendar days, measured from the test's end date, must separate performance tests,

(B) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests,

(C) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and

(iii) At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years.

(2) For units demonstrating compliance through quarterly emission testing, 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 168 or more boiler operating hours occur 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.

[40 C.F.R. §63.10006(f); 45CSR34]

4.3.6. If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in §63.10006(b) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.
[40 C.F.R. §63.10006(h); 45CSR34]

4.3.7. Except as otherwise provided in 40 C.F.R. §63.10007, you must conduct all required performance tests according to 40 C.F.R. §§63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in 40 C.F.R. §63.7(c).
[40 C.F.R. §63.10007(a); 45CSR34]

4.3.8. If you use SO_2 CEMS to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 to this subpart), except as otherwise provided in §63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).
[40 C.F.R. §63.10007(a)(1); 45CSR34]

4.3.9. If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.
[40 C.F.R. §63.10007(a)(2); 45CSR34] (*Particulate Matter*)

4.3.10. You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to 40 C.F.R. 63 Subpart UUUUU.
[40 C.F.R. §63.10007(b); 45CSR34]

4.3.11. Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.
[40 C.F.R. §63.10007(d); 45CSR34] (*Particulate Matter*)

4.3.12. To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 to 40 C.F.R. 63 Subpart UUUUU, proceed as in 40 C.F.R. §§63.10007(e)(1) through (3). If you use quarterly performance testing for coal-fired EGUs to measure compliance with PM emissions limit in Table 2 to Subpart UUUUU, you demonstrate continuous compliance by calculating the results of the testing in units of the applicable emissions standard. (On or after July 6, 2027 you may not use quarterly performance testing for filterable PM compliance demonstrations).
[40 C.F.R. §63.10007(e); 40 C.F.R. §63.10021(a), Table 7, Item #4; 45CSR34]

4.3.13. Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007.
[40 C.F.R. §63.10007(g); 45CSR34]

4.3.14. For candidate LEE units, use the results of the performance testing described in §63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 2 to this subpart and to determine whether the unit qualifies for LEE status.
[40 C.F.R. §63.10011(d); 45CSR34]

4.3.15. If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 to 40 C.F.R. 63 Subpart UUUUU, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year; and

(2) Must conduct the performance test as defined in Table 5 to 40 C.F.R. 63 Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard.

[40 C.F.R. §§63.10021(d), (d)(1), and (d)(2); 45CSR34]

4.3.16. *Notification of performance test*. When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin. *Compliance with this requirement ensures compliance with 40 C.F.R. §§63.7(b) and 63.9(e).*
[40 C.F.R. §63.10030(d) and (a); 40 C.F.R. §§63.7(b) and 63.9(e); 45CSR34]

4.3.17. (A) Before July 6, 2027, ~~If~~ if your coal-fired EGU does not qualify as a LEE for filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(B) On and after July 6, 2027, you may not pursue or continue to use the LEE option for your coal-fired or solid oil derived fuel-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(C) If your IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

[40 C.F.R. §63.10000(c)(1)(iv); 45CSR34]

4.4. Recordkeeping Requirements

4.4.1. Records of monitored data established in the monitoring plan (see Appendix A) shall be maintained on site and shall be made available to the Secretary or his duly authorized representative upon request.
[45CSR§2-8.3.~~a~~1.]

4.4.2. Records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit, shall be maintained on-site in a manner to be established by the Secretary and made available to the Secretary or his duly authorized representative upon request.
[45CSR§2-8.3.~~c~~3.]

4.4.3. Records of the block 3-hour COMS opacity averages and corrective actions taken during excursions of the CAM plan indicator range shall be maintained on site and shall be made available to the Director or his duly authorized representative upon request. COMS performance data will be maintained in accordance with 40 C.F.R. Part 75 recordkeeping requirements.
[45CSR§30-5.1.c. and 40 C.F.R. §64.9(b)]

4.4.4. **General recordkeeping requirements for 40 C.F.R. Part 64 (CAM).** The permittee shall comply with the recordkeeping requirements specified in permit conditions 3.3.1. and 3.3.2. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 C.F.R. §64.8 (condition 4.2.8.) and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 C.F.R. Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).
[40 C.F.R. § 64.9(b); 45CSR§30-5.1.c.]

4.4.5. **Format and Retention of Records for 40 C.F.R. 63 Subpart UUUUU**

(a) Your records must be in a form suitable and readily available for expeditious review, according to 40 C.F.R. §63.10(b)(1).

(b) As specified in 40 C.F.R. §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

[40 C.F.R. §§63.10033(a), (b), and (c); 45CSR34]

4.4.6. You must keep records according to paragraphs (1) and (2) of this condition. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you ~~must also~~elect to use a PM CPMS (unless it is for an IGCC unit, you may only use PM CPMS before July 6, 2027), you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to 40 C.F.R. 63 Subpart UUUUU. If you elect to conduct periodic (e.g., quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

(1) In accordance with 40 CFR 63.10(b)(2)(xiv), ~~A~~ a copy of each notification ~~and~~ or report that you ~~submitted~~ submit to comply with this subpart~~, including all documentation supporting any Initial Notification or~~ .You must also keep records of all supporting documentation for the initial Notifications of Compliance Status, ~~or~~ semiannual compliance reports, ~~that~~ or quarterly compliance reports that you ~~submitted, according to the requirements in §63.10(b)(2)(xiv)~~submit.

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

[40 C.F.R. §63.10032(a); 45CSR34]

4.4.7. For each CEMS, you must keep records according to paragraphs (1) through (4) of this condition.

(1) Records described in §63.10(b)(2)(vi) through (xi).

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

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

(4) 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 C.F.R. §63.10032(b); 45CSR34]

4.4.8. You must keep the records required in Table 7 to 40 C.F.R. 63 Subpart UUUUU to show continuous compliance with each emission limit and operating limit that applies to you (conditions 4.1.4.b., 4.1.5.b., 4.1.8., and 4.1.9.).
[40 C.F.R. §63.10032(c), Table 7, Items #1, #4, #5, #6, #7; 45CSR34]

4.4.9. For each EGU subject to an emission limit, you must also keep the records in paragraphs (1) through (3) of this condition.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under §63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, 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 C.F.R. §63.10032(d); 45CSR34]

4.4.10. 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.

[40 C.F.R. §§63.10032(f) and (f)(1); 45CSR34]

4.4.11. You 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 C.F.R. §63.10032(g); 45CSR34]

4.4.12. You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (permit condition 4.1.10.), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 C.F.R. §63.10032(h); 45CSR34]

4.4.13. You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.
[40 C.F.R. §63.10032(i); 45CSR34]

4.5. Reporting Requirements

4.5.1. The designated representative shall electronically report SO_2, NO_x, and CO_2 emissions data and information as specified in 40 C.F.R. § 75.64 to the Administrator of USEPA, quarterly. Each electronic report must be submitted within thirty (30) days following the end of each calendar quarter.
[45CSR33; 40 C.F.R. §75.64]

4.5.2. A periodic exception report shall be submitted to the Secretary, in a manner and at a frequency to be established by the Secretary. Compliance with this periodic exception reporting requirement shall be demonstrated as outlined in sections I.A.4. and II.A.4. of the DAQ approved "45CSR2 and 45CSR10 Monitoring Plan" attached in Appendix A of this permit.
[45CSR§2-8.3.~~b~~2.]

4.5.3. Excess opacity periods resulting from any malfunction of Unit 1 or Unit 2, or their air pollution control equipment, meeting the following conditions, may be reported on a quarterly basis unless otherwise required by the Secretary:

a. The excess opacity period does not exceed thirty (30) minutes within any twenty-four (24) hour period; and

b. Excess opacity does not exceed forty percent (40%).

[45CSR§2-9.3.~~a~~1.]

4.5.4. Except as provided in permit condition 4.5.3. above, the owner or operator shall report to the Secretary by telephone~~, telefax,~~ or e-mail any malfunction of Unit 1 or Unit 2, or their associated air pollution control equipment, which results in any excess particulate matter or excess opacity, by the end of the next business day after becoming aware of such condition. The owner or operator shall file a certified written report concerning the malfunction with the Secretary within thirty (30) days providing the following information:

a. A detailed explanation of the factors involved or causes of the malfunction;

b. The date, and time of duration (with starting and ending times) of the period of excess emissions;

c. An estimate of the mass of excess emissions discharged during the malfunction period;

d. The maximum opacity measured or observed during the malfunction;

e. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction; and

f. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.~~b~~2.]

4.5.5. Unit 1 & Unit 2 are Phase II Acid Rain affected units under 45CSR33, as defined by 40 C.F.R § 72.6, and as such are required to meet the requirements of 40 C.F.R. Parts 72, 73, 74, 75, 76, 77 and 78. These requirements include, but are not limited to:

a. Hold an Acid Rain permit;

b. Hold allowances, as of the allowance transfer deadline, in the unit's compliance sub-account of not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit;

c. Comply with the applicable Acid Rain emissions for sulfur dioxide;

d. Comply with the applicable Acid Rain emissions for nitrogen oxides;

e. Comply with the monitoring requirements of 40 C.F.R. Part 75 and section 407 of the Clean Air Act of 1990 and regulations implementing section 407 of the Act;

f. Submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 C.F.R. Part 72, Subpart I and 40 C.F.R. Part 75.

[45CSR33; 40 C.F.R. Parts 72, 73, 74, 75, 76, 77, 78]

4.5.6. **General reporting requirements for 40 C.F.R. Part 64 (CAM)**

(a) On and after the date specified in 40 C.F.R. §64.7(a) by which the permittee must use monitoring that meets the requirements of 40 C.F.R. 64, the permittee shall submit monitoring reports to the DAQ in accordance with permit condition 3.4.6.

(b) A report for monitoring under 40 C.F.R. 64 shall include, at a minimum, the information required under permit condition 3.4.8. and the following information, as applicable:

(i) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(ii) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(iii) A description of the actions taken to implement a QIP during the reporting period as specified in 40 C.F.R. §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 C.F.R. § 64.9(a); 45CSR§30-5.1.c.]

4.5.7. You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.
[40 C.F.R. §63.10021(f); 45CSR34]

4.5.8. You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 2 and 3 to 40 C.F.R. 63 Subpart UUUUU or failed to conduct a required tune-up (permit conditions 4.1.4.b., 4.1.5.b., 4.1.8., and 4.1.9.). These instances are deviations from the requirements of this subpart. These deviations must be reported according to §63.10031.
[40 C.F.R. §63.10021(g); 45CSR34]

4.5.9. You must submit all of the notifications in 40 C.F.R. §63.7(c), and §63.8(e), by the dates specified.
[40 C.F.R. §63.10030(a); 45CSR34]

4.5.10. You must submit a Compliance report for 40 C.F.R. 63 Subpart UUUUU containing:

a. Information required in 40 C.F.R. §§63.10031(c)(1) through (4) and (6) through (~~9~~10):

(1) The information required by the summary report located in 40 C.F.R. §63.10(e)(3)(vi).

(2) 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 your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

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

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in §§63.10021(e)(6) and (7) (permit conditions 4.1.9.(6) and (7)) were completed.

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, 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 §63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

(10) If you had any process or control equipment malfunction(s) during the reporting period, you must include the number, duration, and a brief description for each type of malfunction which occurred during the semiannual reporting period which caused or may have caused any applicable emission limitation to be exceeded.

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 40 C.F.R. 63 Subpart UUUUU 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 40 C.F.R. §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 40 C.F.R. §63.10031(d) (section d. of this condition). 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 40 C.F.R. §63.8(c)(7), the report must contain the information in 40 C.F.R. §63.10031(e) (condition 4.5.12.).

d. For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in 40 C.F.R. §63.10(e)(3)(v) in the compliance report specified in section a. of this condition.

e. If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

You must submit the report semiannually according to the requirements in 40 C.F.R. §60.10031(b) (condition 4.5.11.).

[40 C.F.R. §63.10031(a), Table 8, Item #1; 40 C.F.R. §§63.10031(c)(1) through (4) and (6) through (~~9~~10); 40 C.F.R. §63.10031(d); 40 C.F.R. §63.10031(g); 40 C.F.R. §63.10021(i); 45CSR34]

4.5.11. Unless the Administrator has approved a different schedule for submission of reports under 40 C.F.R. §63.10(a), you must submit each report by the date in Table 8 to 40 C.F.R. 63 Subpart UUUUU and according to the requirements in paragraphs (1) through (5) of this condition.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in 40 C.F.R. §63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in 40 C.F.R. §63.9984.

(2) The first 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 first calendar half after the compliance date that is specified for your source in 40 C.F.R. §63.9984.

(3) 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.

(4) 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.

(5) You may submit the first and subsequent compliance reports according to the dates in permit condition 3.5.6. instead of according to the dates in paragraphs (1) through (4) of this condition.

[40 C.F.R. §§63.10031(b)(1) through (5); 45CSR34]

4.5.12. You must report all deviations as defined in 40 C.F.R. 63 Subpart UUUUU in the semiannual monitoring report required by condition 3.5.6. If an affected source submits a compliance report pursuant to Table 8 to 40 C.F.R. 63 Subpart UUUUU (condition 4.5.10.) along with, or as part of, the semiannual monitoring report required by condition 3.5.6., and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 C.F.R. 63 Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.
[40 C.F.R. §§63.10031(e); 45CSR34]

4.5.13. On or after July 1, 2020, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data; CEMS performance evaluation test results; reports for SO_2 CEMS and sorbent trap monitoring system; compliance reports; and all reports required by 40 C.F.R. 63 Subpart UUUUU not subject to the requirements in 40 C.F.R. §63.10031(f) introductory text and §§63.10031(f)(1) through (4) must be submitted as further specified in 40 C.F.R. §§63.10031(f), (f)(1), (3), (4), (5), and (6).
[40 C.F.R. §§ 63.10031(f), (f)(1), (3), (4), (5), and (6); 45CSR34]

4.6. Compliance Plan

4.6.1. There is no compliance plan since a responsible official certified compliance with all applicable requirements in the Title V renewal application.

5.0 Auxiliary Boiler [Emission Unit ID *Aux 1* – Emission Point ID *Aux ML1*]

5.1. Limitations and Standards

5.1.1. ~~Emergency Operating Scenarios~~Reserved

a. ~~In the event of an unavoidable shortage of fuel having characteristics or specifications necessary to comply with the visible emission requirements or any emergency situation or condition creating a threat to public safety or welfare, the Secretary may grant an exemption to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during that period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the weight emission requirements will not be exceeded during the exemption period.~~
~~**[45CSR§2-10.1.]**~~

b. ~~Due to unavoidable malfunction of equipment or inadvertent fuel shortages, SO_2 emissions from the auxiliary boiler exceeding those provided for in 45CSR§§10-3.1.b. and 3.1.e., respectively, may be permitted by the Secretary for periods not to exceed ten (10) days upon specific application to the Secretary. Such application shall be made within twenty-four (24) hours of the equipment malfunction or fuel shortage. In cases of major equipment failure or extended shortages of conforming fuels, additional time periods may be granted by the Secretary, provided a corrective program has been submitted by the owner or operator and approved by the Secretary.~~
~~**[45CSR§10-9.1.]**~~

5.1.2. Any fuel burning unit(s) including associated air pollution control equipment, shall at all times, including periods of start-up, shutdowns, and malfunctions, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions.
[45CSR§2-9.2.]

5.1.3. The following conditions and requirements are specific to the Boiler Aux-1:

a. Emissions from the boiler shall not exceed the following limits:

Pollutant	lb/hr	tpy
SO_2	39.78[1]	17.42
NO_x	99.45	43.56
CO	206.86	90.60
VOC	0.95	0.41
PM (filterable + condensable)	15.63[2]	6.85
PM_{10} (filterable + condensable)	10.90	4.77
$PM_{2.5}$ (filterable + condensable)	7.34	3.22
CO_2	105,606.4	46,255.6
N_2O	0.88	0.38
CH_4	4.38	1.92
CO_{2e} (Total)	105,971.18	46,413.72
Formaldehyde	0.29	0.13
Benzene	0.01	0.01
Ethylbenzene	0.01	0.01

Toluene	0.03	0.02
Xylene	0.01	0.01
Naphthalene	0.01	0.01

[1] This limit makes 40 C.F.R. §60.42b(k)(2) applicable and excludes the unit from limitations of 40 C.F.R. §60.42b(k)(1). This limit satisfies the limitation in 45CSR§10-3.1.b. (4,972.5 lb/hr of SO_2).
[2] Compliance with this PM limitation ensures compliance with the 45CSR§2-4.1.b. limit of 59.67 lb/hr.
[45CSR§2-4.1.~~b~~2.; 45CSR§10-3.1.b.]

b. Boiler Aux-1 shall be fitted with Low NO_x burners and shall utilize Flue Gas Recirculation.

c. The permittee shall limit the annual capacity of the boiler to no more than 10 percent by limiting the annual average heat input of the boiler to 580,788 MMBtu per year. Compliance with this limit shall be satisfied though compliance with the annual fuel usage limit in item d of this condition.
[40 C.F.R. §60.44b(c); 45CSR16; 40 C.F.R. §63.7575; 45CSR34; 45CSR§2-8.4.~~a~~1.~~1~~a.]

d. For the purpose of complying with the SO_2 limits in item a of this condition, the Boiler Aux-1 shall not consume more than 4,736 gallons of fuel oil (distillate oil) per hour nor more than 4,148,736 gallons per year. Such fuel oil can not contain more than 600 ppm or 0.06 % of sulfur, which makes the sulfur dioxide potential for this unit at no greater than 0.06 lb/MMBtu.
[40 C.F.R. §60.42b(k)(2), §60.43b(h)(5), and §60.48b(j)(2); 45CSR16; 45CSR§10-10.2]

e. Opacity from boiler shall not exceed 20% based on a 6-minute average, except for one 6-minute period per hour of not more than 27% opacity, except during periods of startup, shutdown, or malfunction.
[40 C.F.R. §§60.43b(f) & (g); 45CSR16]

f. Visible emissions from the boiler shall not exceed 10 percent opacity based on a six minute block average~~, except during periods of startup, shutdown, or malfunction~~.
[45CSR§§2-3.1~~. and 9.1.]~~

[45CSR13, R13-2608, 5.1.1.]

5.1.4. Compliance with the allowable sulfur dioxide emission limitations from the auxiliary boiler shall be based on a continuous twenty-four (24) hour averaging time. Emissions shall not be allowed to exceed the weight emissions standards for sulfur dioxide as set forth in 45CSR10, except during one (1) continuous twenty-four (24) hour period in each calendar month. During this one (1) continuous twenty-four hour period, emissions shall not be allowed to exceed such weight emission standards by more than ten percent (10%) without causing a violation of 45CSR10. A continuous twenty-four (24) hour period is defined as one (1) calendar day.
[45CSR§10-3.8.]

5.1.5. **Compliance Date for 40 C.F.R. 63 Subpart DDDDD.** If you have an existing boiler or process heater, you must comply with 40 C.F.R. 63 Subpart DDDDD no later than January 31, 2016, except as provided in 40 C.F.R. §63.6(i).
[40 C.F.R. §63.7495(b); 45CSR34]

5.1.6. **Periodic Tune-ups under 40 C.F.R. 63 Subpart DDDDD.** If your boiler meets the definition of limited-use boiler or process heater in 40 C.F.R. §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of 40 C.F.R. §63.7540 (paragraphs (i) through (vi) of this condition) to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (i) of this condition until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. 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;

(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 (you 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, if available, and with any NO_X requirement to which the unit is subject;

(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). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (vi)(A) and (B) of this condition.

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;
(B) A description of any corrective actions taken as a part of the tune-up.

- If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.
- Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up.

[40 C.F.R. §§ 63.7500(c), 63.7540(a)(10), 63.7540(a)(12), 63.7540(a)(13), 63.7505(a), 63.7515(d); 45CSR34; 45CSR13, R13-2608, 5.1.1.g. and 5.4.4.]

5.2. Monitoring Requirements

5.2.1. Compliance with the visible emission requirements for *Aux ML1* shall be determined as outlined in section I.B.2. of the DAQ approved “45CSR2 Monitoring Plan” attached in Appendix A of this permit.
[45CSR§§2-3.2. and 8.2.]

5.2.2. Compliance with the auxiliary boiler stack (*Aux ML1*) particulate matter mass emission requirements and the operating and fuel usage requirements for the auxiliary boiler, shall be demonstrated as outlined in section I.B.3. of the DAQ approved "45CSR2 Monitoring Plan" attached in Appendix A of this permit. **[45CSR§§2-8.3.~~c~~3., 8.4.~~a~~1. and 8.4.~~a~~1.~~1~~a.]**

5.2.3. In order to determine compliance with condition 5.1.3.d of this permit, the permittee shall monitor and record the amount of fuel oil combusted by Boiler Aux-1 on a monthly basis. Compliance with fuel usage limitations in item d will constitute compliance with the emission limitations of item a. of Condition 5.1.3. Such records shall be maintained in accordance with condition 3.4.2.
[45CSR13, R13-2608, 5.2.1.; 40 C.F.R. §60.49b(d)(2); 45CSR16; 45CSR§2-8.3.~~c~~3.; 45CSR§§10-8.2.~~c~~3.~~3~~c. and 8.3.~~c~~3.]

5.2.4. The permittee shall obtain records indicating the fuel oil received at the facility for Boiler Aux 1 meets the specification of distillate oil as defined in 40 C.F.R. §60.41b and sulfur content stated in item d. of condition 5.1.3. from the fuel supplier. Such records shall be maintained in accordance with condition 3.4.2. **[45CSR13, R13-2608, 5.2.2.; 40 C.F.R. §60.49b(r)(1); 45CSR16; 45CSR§10-8.2.~~c~~3.~~3~~c.]**

5.2.5. The permittee shall conduct subsequent visible emission observations of the emission point for Boiler Aux-1 at least once every 12 months from the date of the most recent observation. Such observations shall be conducted using Method 9 of Appendix A-4 of Part 60. If visible emissions are observed, the permittee must follow the subsequent observation schedule in 40 C.F.R. §60.48b(a)(1)(ii) through (iv) as applicable. Records of Method 9 observations shall contain the following:

a. Dates and time intervals of all opacity observation periods;
b. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and
c. Copies of all visible emission observer opacity field data sheets;

If the most recent observation is less than 10 percent opacity, the permittee may use Method 22 of Appendix A-7 of Part 60 to demonstrate compliance in lieu of using Method 9. The use of Method 22 observations must be in accordance with the length of observation and frequency as outlined in 40 C.F.R. §60.48b(a)(2)(i) through (ii) as applicable. Records of Method 22 observations shall contain the following:

a. Dates and time intervals of all visible emissions observation periods;
b. Name and affiliation for each visible emission observer participating in the performance test;
c. Copies of all visible emission observer opacity field data sheets; and
d. Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

Records of observations shall be maintained in accordance with condition 3.4.2.

[45CSR13, R13-2608, 5.2.3.; 40 C.F.R. §§60.48b(a) and 60.49b(f); 45CSR16; 45CSR§2-8.1.~~a~~1.]

5.3. Testing Requirements

5.3.1. Reserved.

5.4. Recordkeeping Requirements

5.4.1. Records of monitored data established in the monitoring plan (see Appendix A) shall be maintained on site and shall be made available to the Secretary or his duly authorized representative upon request
[45CSR§2-8.3.~~a~~1.]

5.4.2. Records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit, shall be maintained on-site in a manner to be established by the Secretary and made available to the Secretary or his duly authorized representative upon request
[45CSR§2-8.3.~~c~~3.]

5.4.3. You must keep records according to paragraphs (1), (2), and (3) of this condition.

(1) A copy of each notification and report that you submitted to comply with 40 C.F.R. 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual* compliance report that you submitted, according to the requirements in 40 C.F.R. §63.10(b)(2)(xiv).
** Note – Compliance reports are required only once every 5 years for the limited use boiler Aux 1 pursuant to 40 C.F.R. §63.7550(b) in permit condition 5.5.5.*

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 C.F.R. §63.10(b)(2)(viii).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

[40 C.F.R. §§63.7555(a) and 63.7525(k); 45CSR34]

5.4.4. **Format and Retention of Records for 40 C.F.R. 63 Subpart DDDDD**

(a) Your records must be in a form suitable and readily available for expeditious review, according to 40 C.F.R. §63.10(b)(1).

(b) As specified in 40 C.F.R. §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 C.F.R. §63.10(b)(1). You can keep the records off site for the remaining 3 years.

[40 C.F.R. §§63.7560(a), (b), and (c); 45CSR34]

5.5. Reporting Requirements

5.5.1. A periodic exception report shall be submitted to the Secretary, in a manner and at a frequency to be established by the Secretary. Compliance with this periodic exception reporting requirement shall be demonstrated as outlined in section I.B.4. of the DAQ approved "45CSR2 and 45CSR10 Monitoring Plan" attached in Appendix A of this permit.
[45CSR§2-8.3.~~b~~2.]

5.5.2. Excess opacity periods resulting from any malfunction of Aux 1 or its air pollution control equipment, meeting the following conditions, may be reported on a quarterly basis unless otherwise required by the Secretary:

a. The excess opacity period does not exceed thirty (30) minutes within any twenty-four (24) hour period; and

b. Excess opacity does not exceed forty percent (40%).

[45CSR§2-9.3.~~a~~1.]

5.5.3. Except as provided in permit condition 5.5.2. above, the owner or operator shall report to the Secretary by telephone~~, telefax,~~ or e-mail any malfunction of Aux1 or its associated air pollution control equipment, which results in any excess particulate matter or excess opacity, by the end of the next business day after becoming aware of such condition. The owner or operator shall file a certified written report concerning the malfunction with the Secretary within thirty (30) days providing the following information:

a. A detailed explanation of the factors involved or causes of the malfunction;

b. The date, and time of duration (with starting and ending times) of the period of excess emissions;

c. An estimate of the mass of excess emissions discharged during the malfunction period;

d. The maximum opacity measured or observed during the malfunction;

e. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction; and

f. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.~~b~~2.]

5.5.4. You must report each instance in which you did not meet each work practice standard in Table 3 to 40 C.F.R. 63 Subpart DDDDD that applies to you (condition 5.1.6.). These instances are deviations from the work practice standards in 40 C.F.R. 63 Subpart DDDDD. These deviations must be reported according to the requirements in 40 C.F.R. §63.7550 (condition 5.5.5.).
[40 C.F.R. §63.7540(b); 45CSR34]

5.5.5. You must submit a Compliance report for 40 C.F.R. 63 Subpart DDDDD containing:

a. The information in §63.7550(c)(5)(i) through (iv), (xiv), and (xvii), which is:

(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 C.F.R. §63.7540(a)(12). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled or unscheduled unit shutdown.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

b. If there are no deviations from the requirements for work practice standards in Table 3 to 40 C.F.R. 63 Subpart DDDDD that apply to you (condition 5.1.6.), a statement that there were no deviations from the work practice standards during the reporting period.

You must submit the report every 5 years according to the requirements in 40 C.F.R. §63.7550(b), which are:

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 C.F.R. §63.7495 (condition 5.1.5.) and ending on July 31 or January 31, whichever date is the first date that occurs at least 5 years after the compliance date that is specified for your source in 40 C.F.R. §63.7495 (condition 5.1.5.).

(2) The first 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent 5-year compliance report must cover the 5-year periods from January 1 to December 31.

(4) Each subsequent 5-year compliance report must be postmarked or submitted no later than January 31.

(5) You may submit the first and subsequent compliance reports according to the dates established in permit condition 3.5.6. instead of according to the dates in paragraphs b. (1) through (4) of this condition.

You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[40 C.F.R. §§63.7550(a), Table 9, Items # 1.a. and # 1.b.; 40 C.F.R. §§63.7550(b), and (c)(1); 40 C.F.R. §63.7550(h)(3); 45CSR34; 45CSR13, R13-2608, 5.5.2.]

5.5.6. The permittee shall report any observation made in accordance with Condition 5.2.5. that indicate visible emissions in excess of either items e and/or f of condition 5.1.3. made during January 1 to June 30 in the facility's Title V Semi Annual Compliance Report or July 1 to December 31 as part of the facility's Title V Annual Compliance Report. Such report shall include the record of the recorded observation in accordance with condition 5.2.5. and measures taken as result of the observation. This reporting requirement can be satisfied by including the results of the exceeded observation(s) with the facility's quarterly opacity report and list the exceedance in the facility's Title V annual compliance certification report.
[45CSR13, R13-2608, 5.5.3.; 40 C.F.R. §60.49b(h); 45CSR16; 45CSR§2-8.3.~~b~~2.]

5.6. Compliance Plan

5.6.1. Reserved.

6.0 Material Handling [Emission point IDs identified in Equipment Table subsection 1.1.]

6.1. Limitations and Standards

6.1.1. Limestone transferred across belt conveyor BC-1 to Transfer House #1 [TH-1] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.
[45CSR13, R13-2608, 4.1.1.]

6.1.2. Limestone transferred across belt conveyor BC-3 to Transfer House #2 [TH-2] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.
[45CSR13, R13-2608, 4.1.2.]

6.1.3. Gypsum transferred across belt conveyor BC-9 to Transfer House #4 [TH-4] shall be limited to a maximum transfer rate of 200 tons per hour and 1,700,000 tons per year.
[45CSR13, R13-2608, 4.1.3.]

6.1.4. Gypsum and wastewater treatment system cake transferred across belt conveyor BC-14 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,912,000 tons per year.
[45CSR13, R13-2608, 4.1.4.]

6.1.5. Gypsum transferred across belt conveyor BC-17 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 750 tons per hour and 1,200,000 tons per year.
[45CSR13, R13-2608, 4.1.5.]

6.1.6. Gypsum transferred across belt conveyor BC-19 to Transfer House #9 [TH-9] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,700,000 tons per year.
[45CSR13, R13-2608, 4.1.6.]

6.1.7. Coal transferred across belt conveyor HSC-1 shall be limited to a maximum transfer rate of 3,000 tons per hour and 5,732,544 tons per year.
[45CSR13, R13-2608, 4.1.7.]

6.1.8. Dry Sorbent (Trona or Hydrated Lime) for SO_3 mitigation shall be delivered to the facility at a maximum annual rate of 81,000 tons per year.
[45CSR13, R13-2608, 4.1.8.]

6.1.9. Liquid magnesium hydroxide shall be delivered to the facility at a maximum annual rate of 6,600,000 gallons per year.
[45CSR13, R13-2608, 4.1.9.]

6.1.10. Hydrated lime for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 3,200 tons per year.
[45CSR13, R13-2608, 4.1.10.]

6.1.11. Ferric Chloride for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 110,000 gallons per year.
[45CSR13, R13-2608, 4.1.11.]

6.1.12. Acid (hydrochloric or sulfuric) for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 170,000 gallons per year.
[45CSR13, R13-2608, 4.1.12.]

6.1.13. Polymer and organosulfide for the FGD wastewater treatment facility shall be delivered to the facility at a maximum annual rate of 13,500 gallons per year.
[45CSR13, R13-2608, 4.1.13.]

6.1.14. The diesel-fired engines [6S and 7S] used to power the emergency quench water system shall be limited to a total maximum combined annual operating schedule of 200 hours per year.
[45CSR13, R13-2608, 4.1.14.]

6.1.15. Compliance with all annual operating limits shall be determined using a twelve month rolling total. A twelve month rolling total shall mean the sum of the quantified operating data at any given time during the previous twelve (12) consecutive calendar months.
[45CSR13, R13-2608, 4.1.15.]

6.1.16. The permittee shall maintain a water truck on site and in good operating condition, and shall utilize same to apply water as often as is necessary in order to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads and other work areas where mobile equipment is used. The spraybar shall be equipped with spray nozzles, of sufficient size and number, so as to provide adequate coverage to the area being treated.

The pump delivering the water shall be of sufficient size and capacity so as to be capable of delivering to the spray nozzle(s) an adequate quantity of water and at a sufficient pressure, so as to assure that the treatment process will minimize the atmospheric entrainment of fugitive particulate emissions generated from the haulroads and work areas where mobile equipment is used.

[45CSR13, R13-2608, 4.1.16.]

6.1.17. Additionally, at least three times per year the permittee shall apply a mixture of water and an environmentally acceptable dust control additive hereafter referred to as solution to all unpaved haul roads. The solution shall have a concentration of dust control additive sufficient to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads.
[45CSR13, R13-2608, 4.1.17.]

6.1.18. The installation and operation of the proposed Limestone Material Handling equipment [1S] and Limestone Processing equipment [3S] shall be subject to the limits and requirements set forth by 40 C.F.R. 60 - Subpart OOO, *“Standards of performance for non-metallic mineral processing plants.”*

a. The material transfers across the conveyors within the enclosed transfer stations and ball mill within the processing building will be limited to the opacity emissions from the building or building vents. The buildings will be limited to emissions of no visible opacity per 40 C.F.R. §60.672(e)(1), and the vents from the buildings will be limited to an opacity of 7% and particulate emissions of 0.022 grains per dry standard cubic foot, per 40 C.F.R. §60.672(e)(2).

b. The emissions from the baghouse on each of the limestone day bins will be limited to 7% opacity per 40 C.F.R. §60.672(f).

c. All material transfer points outside of the buildings will be limited to a maximum 10% opacity per 40 C.F.R. §60.672(b).

d. In order to comply with the emission and opacity limitations of 40 C.F.R. 60 Subpart OOO, the permittee shall employ dust suppression methods to minimize particulate emissions from the limestone processing equipment. In order to demonstrate compliance, in accordance to the requirements of the regulation, the applicant shall conduct performance testing and monitoring activities as set forth by 40 C.F.R. 60 Subpart OOO.

[45CSR13, R13-2608, 4.1.19.; 40 C.F.R. Part 60, Subpart OOO; 45CSR16]

6.1.19. The maximum amount of fly ash handled by the fly ash handling system shall not exceed 800,000 tons per year on a dry (1% moisture) basis (i.e. 980,000 tons per year at 20% moisture). Compliance with the throughput limit shall be determined using a rolling yearly total. A rolling yearly total shall mean the sum of the fly ash transferred for the previous twelve (12) consecutive calendar months.
[45CSR13, R13-2608, 4.1.20.]

6.1.20. PM emissions from Mechanical Exhausters ME-1A, ME-1B and ME-1C shall not exceed 0.16 lb/hr and 0.69 tpy individually nor 0.32 lb/hr and 1.38 tons per year combined.
[45CSR13, R13-2608, 4.1.21.]

6.1.21. PM emissions from Mechanical Exhausters ME-2A, ME-2B and ME-2C shall not exceed 0.15 lb/hr and 0.65 tpy individually nor 0.30 lb/hr and 1.30 tons per year combined.
[45CSR13, R13-2608, 4.1.22.]

6.1.22. PM emissions from Bin Vent Filters BVF-A, BVF-B and BVF-C shall not exceed 0.75 lb/hr nor 3.25 tpy combined.
[45CSR13, R13-2608, 4.1.23.]

6.1.23. PM emissions from the transfer of conditioned fly ash from the silos to trucks (WFA-AA, WFA-AB, WFA-BA, WFA-BB, WFA-CA, and WFA-CB) shall not exceed 0.07 pounds per hour nor 0.09 tons per year combined.
[45CSR13, R13-2608, 4.1.24.]

6.1.24. The Coal and Ash handling systems, and FGD and SCR material handling systems, are subject to 45CSR§2-5 as outlined in the facility wide section of this permit (condition 3.1.9.) regarding fugitive dust control system.

6.2. Monitoring Requirements

6.2.1. For the purpose of determining compliance with the material transfer limits set forth by Section 6.1.1. and 6.1.2. of this permit, the permittee shall monitor the hourly and annual limestone transfer rates across belt conveyor BC-1 to Transfer House #1 [TH-1] and across belt conveyor BC-3 to Transfer House #2 [TH-2].
[45CSR13, R13-2608, 4.2.1.]

6.2.2. For the purpose of determining compliance with the material transfer limits set forth by Sections 6.1.3., 6.1.4., 6.1.5. and 6.1.6. of this permit, the permittee shall monitor the hourly and annual gypsum and wastewater treatment cake transfer rates across belt conveyors BC-9 to Transfer House #4 [TH-4], BC-14 to Transfer House #7 [TH-7], BC-17 to the Transfer House #7 Extension, and BC-19 to Transfer House #9 [TH-9].
[45CSR13, R13-2608, 4.2.2.]

6.2.3. For the purpose of determining compliance with the material transfer limits set forth by Section 6.1.7. of this permit, the permittee shall monitor the hourly and annual coal transfer rates across belt conveyor HSC-1 to Transfer Station #2A.
[45CSR13, R13-2608, 4.2.3.]

6.2.4. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the SO_3 mitigation system, as set forth by Section 6.1.8. and 6.1.9. of this permit, the permittee shall monitor the on-site delivery of dry sorbent (including trona and hydrated lime) and liquid magnesium hydroxide.
[45CSR13, R13-2608, 4.2.4.]

6.2.5. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the FGD wastewater treatment system, as set forth by Sections 6.1.10. through 6.1.13. of this permit, the permittee shall monitor the on-site delivery of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide.
[45CSR13, R13-2608, 4.2.5.]

6.2.6. For the purpose of determining compliance with the operating limits set forth by Section 6.1.14. of this permit, the permittee shall monitor the operating schedule of the diesel-fired engines [6S and 7S] used to power the emergency quench water system.
[45CSR13, R13-2608, 4.2.6.]

6.2.7. For the purpose of determining compliance with the limits associated with disposal of dry fly ash, as set forth by Section 6.1.19 of this permit, the permittee shall monitor and record the amount of dry fly ash disposed of.
[45CSR13, R13-2608, 4.2.7.]

6.2.8. For the purpose of determining compliance with the operating limits set forth by Section 6.1.17. of this permit, the permittee shall monitor and record the date that chemical solution is applied to the haulroads along with the amount and concentration of the solution applied.
[45CSR13, R13-2608, 4.2.8.]

6.3. Testing Requirements

6.3.1. Within 120 days of startup of the dry ash handling system, the permittee shall perform or have performed EPA approved tests (or other methods as approved by WVDAQ) to determine maximum PM emissions from any one of the Silo Bin Vent Filters (BVF-A, BVF-B or BVF-C).
[45CSR13, R13-2608, 4.3.2.]

6.4. Recordkeeping Requirements

6.4.1. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.1. of this permit, the permittee shall maintain monthly records of the amount of limestone transferred across the monitored belt conveyors.
[45CSR13, R13-2608, 4.4.4.]

6.4.2. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.2. of this permit, the permittee shall maintain monthly records of the amount of gypsum and wastewater treatment cake transferred across the monitored belt conveyors.
[45CSR13, R13-2608, 4.4.5.]

6.4.3. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.3. of this permit, the permittee shall maintain monthly records of the amount of coal transferred across the monitored belt conveyor.
[45CSR13, R13-2608, 4.4.6.]

6.4.4. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.4. of this permit, the permittee shall maintain monthly records of the amount of dry sorbent (trona and hydrated lime) and liquid magnesium hydroxide delivered to the facility via truck.
[45CSR13, R13-2608, 4.4.7.]

6.4.5. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.5. of this permit, the permittee shall maintain monthly records of the amount of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide delivered to the facility via truck.
[45CSR13, R13-2608, 4.4.8.]

6.4.6. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.6. of this permit, the permittee shall maintain monthly records of the hours of operation of the diesel-fired engines [6S and 7S].
[45CSR13, R13-2608, 4.4.9.]

6.4.7. For the purposes of determining compliance with Section 6.1.16., 6.1.17., and 3.1.9. of this permit, the permittee shall maintain records of the amount of dust control additive used at the facility and the dates the solution was applied.
[45CSR13, R13-2608, 4.4.10.]

6.4.8. All records produced in accordance to the requirements set forth by Sections 6.4.1. through 6.4.7. of this permit shall be maintained in accordance with Section 3.3.4. of this permit. At a time prior to being submitted to the Director, all records shall be certified and signed by a "Responsible Official" or a duly authorized representative, utilizing the attached Certification of Data Accuracy statement (Appendix B).
[45CSR13, R13-2608, 4.4.11.]

6.4.9. For the purposes of determining compliance with the maximum throughput limit set forth in Condition 6.1.19. above, the facility shall maintain monthly (and calculated rolling yearly total) records of the amount of fly ash handled by the Units 1 and 2 fly ash system.
[45CSR13, R13-2608, 4.4.12.]

6.5. Reporting Requirements

6.5.1. Reserved.

6.6. Compliance Plan

6.6.1. A compliance plan is not included since a Responsible Official certified compliance with all applicable requirements in the renewal application.

7.0 Emergency Quench Water Pump Diesel-fired Engines [emission unit IDs: 6S, 7S; emission point IDs: 15E, 16E]

7.1. Limitations and Standards

7.1.1. If you have an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013.
[40 C.F.R. §63.6595(a)(1); 45CSR34]

7.1.2. For emergency stationary CI RICE[1], you must meet the following requirements, except during periods of startup:

a. Change oil and filter every 500 hours of operation or ~~annually~~within 1 year + 30 days of the previous change, whichever comes first;[2]
b. Inspect air cleaner every 1,000 hours of operation or ~~annually~~within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;
c. Inspect all hoses and belts every 500 hours of operation or ~~annually~~within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.[3]

During periods of startup you must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of 40 C.F.R. 63 Subpart ZZZZ, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in 40 C.F.R. §63.6625(i) (permit condition 7.1.6.) in order to extend the specified oil change requirement in Table 2c of 40 C.F.R. 63 Subpart ZZZZ.

[3] Sources can petition the Administrator pursuant to the requirements of 40 C.F.R. §63.6(g) for alternative work practices.

[40 C.F.R. §63.6602, Table 2c, Row 1; 40 C.F.R. §63.6625(h); 45CSR34]

7.1.3. At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator 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 C.F.R. §63.6605(b); 45CSR34]

7.1.4. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
[40 C.F.R. §§63.6625(e) and 63.6625(e)(2); 40 C.F.R. §63.6640(a), Table 6, Item #9; 45CSR34]

7.1.5. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.
[40 C.F.R. §63.6625(f); 45CSR34]

7.1.6. If you own or operate a stationary CI engine that is subject to the work, operation or management practices in item 1 of table 2c to 40 C.F.R. 63 Subpart ZZZZ (permit condition 7.1.2.), you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in table 2c to 40 C.F.R. 63 Subpart ZZZZ. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c to 40 C.F.R. 63 Subpart ZZZZ (permit condition 7.1.2.a.). The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine (permit condition 7.1.4.).
[40 C.F.R. §63.6625(i); 45CSR34]

7.1.7. If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (1) through (3) of this condition. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (1) through (3) of this condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this condition, the engine will not be considered an emergency engine under 40 C.F.R. 63 Subpart ZZZZ and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (2)(i) of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this condition counts as part of the 100 hours per calendar year allowed by this paragraph (2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (2) of this condition. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[40 C.F.R. §§63.6640(f) and 63.6640(f)(1), (f)(2), and (f)(3); 45CSR34]

7.2. Monitoring Requirements

7.2.1. Reserved.

7.3. Testing Requirements

7.3.1. Reserved.

7.4. Recordkeeping Requirements

7.4.1. You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan (permit condition 7.1.4.) if you own or operate an existing stationary emergency RICE.
[40 C.F.R. §§63.6655(e) and 63.6655(e)(2); 45CSR34]

7.4.2. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. ~~If the engine is used for the purposes specified in 40 C.F.R. §63.6640(f)(2)(ii) or (iii) (condition 7.1.7.(2)(ii) or (iii)), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.~~
[40 C.F.R. §§63.6655(f) and 63.6655(f)(1); 45CSR34]

7.4.3. **Form and Retention of Records for 40 C.F.R. 63 Subpart ZZZZ**.

(a) Your records must be in a form suitable and readily available for expeditious review according to 40 C.F.R. §63.10(b)(1).

(b) As specified in 40 C.F.R. §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 C.F.R. §63.10(b)(1).

[40 C.F.R. §§63.6660(a), (b), and (c); 45CSR34]

7.5. Reporting Requirements

7.5.1. You must report each instance in which you did not meet each limitation in Table 2c to 40 C.F.R. 63 Subpart ZZZZ (permit condition 7.1.2.). These instances are deviations from the emission and operating limitations in 40 C.F.R. 63 Subpart ZZZZ. These deviations must be reported according to the requirements in 40 C.F.R. §63.6650 (permit condition 7.5.3.).
[40 C.F.R. §63.6640(b); 45CSR34]

7.5.2. You must also report each instance in which you did not meet the requirements in Table 8 to 40 C.F.R. 63 Subpart ZZZZ that apply to you.
[40 C.F.R. §63.6640(e); 45CSR34]

7.5.3. The permittee must report all deviations as defined in 40 C.F.R. 63 Subpart ZZZZ in the semiannual monitoring report required by permit condition 3.5.6.
[40 C.F.R. §63.6650(f); 45CSR34]

7.6. Compliance Plan

7.6.1. A compliance plan is not included since a Responsible Official certified compliance with all applicable requirements in the renewal application.

8.0 Liquid Propane Vapor Engine Driven Emergency Generator, Black Start Emergency Generators, Diesel Fuel Storage Tank, Diesel Driven Emergency Generators, and Diesel Driven Emergency Fire Pump Engines [emission point ID(s): LPG, EG-1, EG-2, EGT01, EGT02, LF DEG, LF DEG2, 17E and 18E]

8.1. Limitations and Standards

8.1.1. **Emission Limitations**. The registrant shall not cause, suffer, allow or permit emissions of VOC, NO_X, and CO, from any registered reciprocating internal combustion engine to exceed the potential to emit (pounds per hour and tons per year) listed in the General Permit Registration.

Source ID#	Nitrogen Oxides		Carbon Monoxide		Volatile Organic Compounds	
	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]
LPG	0.74	0.19	21.75	5.44	0.22	0.06
EG-1	59.9	14.98	7.66	1.92	0.94	0.24
EG-2	36.4	9.1	4.85	1.21	1.18	0.30
TOTAL	97.04	24.27	34.26	8.57	2.34	0.60

[1] Based on operating the engine 500 hours per year. Compliance with the yearly limitations shall be determined using a twelve-month rolling total. A twelve-month rolling total shall mean the sum of the hours or operation at any given time during the previous twelve consecutive calendar months.

[45CSR13, G60-C057 General Permit Registration, Emission Limitations; General Permit G60-D, Conditions 5.1.2. and 5.1.3.]

8.1.2. The applicable emergency generator(s) shall be operated and maintained as follows:

a. In accordance with the manufacturer's recommendations and specifications or in accordance with a site-specific maintenance plan; and,

b. In a manner consistent with good operating practices.

[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.4.]

8.1.3. The emission limitations specified in section 8.1.1. shall apply at all times except during periods of start-up and shut-down provided that the duration of these periods does not exceed 30 minutes per occurrence. The registrant shall operate the engine in a manner consistent with good air pollution control practices for minimizing emissions at all times, including periods of start-up and shut-down. The emissions from start-up and shut-down shall be included in the twelve (12) month rolling total of emissions. The registrant shall comply with all applicable start-up and shut-down requirements in accordance with 40 CFR Part 60, Subparts IIII, JJJJ and 40 CFR Part 63, Subpart ZZZZ.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.7.]

8.1.4. All tanks in the General Permit Registration application will be listed in Section 1.0 (the emission unit table) of the issued registration. Tanks are to be used for fuel storage for the emergency generators (EG-1, EG-2) only.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 6.1.1.] (EGT01, EGT02)

8.1.5. **40 C.F.R. 60 Subpart IIII – Manufacturer Certification**.

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of 40 C.F.R. §60.4202.

(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.

[40 C.F.R. §§ 60.4205(b) and 60.4202(a)(2); 40 C.F.R. §1039, Appendix I; 45CSR16] (LF DEG, LF DEG2)

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraph (2) of this condition.

(2) For 2011 model year and later, the Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

NMHC+NOx (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
6.4	3.5	0.20

[40 C.F.R. §§ 60.4205(b) and 60.4202(b)(2); 40 C.F.R. §1039, Table 2 to Appendix I; 45CSR16; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2)

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

[40 C.F.R. §§ 60.4205(c) and 60.4202(d); 45CSR16] (17E, 18E)

8.1.6. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §60.4205 (condition 8.1.5.) over the entire life of the engine.
[40 C.F.R. §60.4206; 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2, 17E, 18E)

8.1.7. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to 40 C.F.R. 60 Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel.

(1) Sulfur content - 15 ppm maximum

(2) Cetane index or aromatic content as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

[40 C.F.R. §60.4207(b); 40 C.F.R. §§ 1090.305(b), (c)(1), and (c)(2); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2, 17E, 18E)

8.1.8. a. If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under Condition 8.1.8.c. of this permit:

1. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

2. Change only those emission-related settings that are permitted by the manufacturer; and

3. Meet the requirements of 40 CFR part 1068, as they apply to you.

b. If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in Condition 8.1.5~~.~~a. or b. of this permit, or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in ~~§ 60.4205(c)~~Condition 8.1.5.c, you must comply by purchasing an engine certified to the emission standards in Condition 8.1.5. for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in Condition 8.1.8.c. of this permit.

c. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. **(LF DEG, 17E, 18E)**

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within

1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards. **(EG-1, EG-2, LF DEG2)**

[40 C.F.R. §§ 60.4211(a), (c), (g), (g)(2), and (g)(3); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2, 17E, 18E)

8.1.9. If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (1) through (3) of this condition. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (1) through (3) of this condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this condition, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (2)(i) of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this condition counts as part of the 100 hours per calendar year allowed by this paragraph (2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (2) of this condition. Except as provided in paragraph (3)(i) of this condition, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[40 C.F.R. §60.4211(f); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2, 17E, 18E)

8.1.10. Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) must comply with the emission standards in Table 1 to 40 C.F.R. 60 Subpart JJJJ for their stationary SI ICE.

NO_x (g/HP-hr)	CO (g/HP-hr)
10 [1]	387

[1] The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X + HC.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4233(e) and Table 1 of 40 C.F.R. 60 Subpart JJJJ; 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.11. Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 (condition 8.1.10.) over the entire life of the engine. *Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).*
[40 C.F.R. §60.4234; 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.12. If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine. *Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).*
[40 C.F.R. §60.4237(c); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.13. If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (1) through (3) of this condition. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (1) through (3) of this condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this condition, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (2)(i) of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this condition counts as part of the 100 hours per calendar year allowed by this paragraph (2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (2) of this condition. Except as provided in paragraph (3)(i) of this condition, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;
(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
(D) The power is provided only to the facility itself or to support the local transmission and distribution system.
(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4243(d); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.14. *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of 40 C.F.R. §63.6590 must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[40 C.F.R. §§63.6590(c)(6) and (c)(7), 45CSR34] ~~[~~(LF DEG, 17E, 18E~~]~~)

8.1.15. *Stationary RICE subject to Regulations under 40 CFR Part 60.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of 40 C.F.R. §63.6590 does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

[40 C.F.R. §§63.6590(b)(1)(i), 45CSR34] ~~[~~(LF DEG2~~]~~)

8.2. Monitoring Requirements

8.2.1. If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.
[40 C.F.R. §60.4209(a); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2~~) (~~,17E, 18E)

8.3. Testing Requirements

8.3.1. Reserved.

8.4. Recordkeeping Requirements

8.4.1. To demonstrate compliance with permit condition 8.1.1., the registrant shall maintain records of the hours of operation of the emergency generators on a monthly basis.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.3.1.]

8.4.2. To demonstrate compliance with permit condition 8.1.2., the registrant shall maintain records of the maintenance performed on each emergency generator.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.3.2.]

8.4.3. All records required by conditions 8.4.1. and 8.4.2. shall be maintained in accordance with condition 3.4.2. of this permit.

[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.3.5.]

8.4.4. If the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
[40 C.F.R. §60.4214(b); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (EG-1, EG-2) (LF DEG, LF DEG2~~) (~~,17E, 18E)

8.4.5. If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(e) (condition 8.1.10.), you must demonstrate compliance according to the method specified in paragraph (1) of this condition.

(1) Purchasing an engine certified according to procedures specified in 40 C.F.R. 60 Subpart JJJJ, for the same model year and demonstrating compliance according to the method specified in paragraph (a) of 40 C.F.R. §60.4243:

i. If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

ii. If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(ii) of §60.4243:

- If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

  Note: The 2019 renewal application does not indicate that the manufacturer-certified engine LPG will not be operated and maintained according to the manufacturer's emission-related written instructions; therefore, condition 8.4.5.(1) i. is applicable.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §§ 60.4243(b) and (b)(1); 40 C.F.R. §§ 60.4243(a)(1) and (a)(2)(ii); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (LPG)

8.4.6. Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (1) through (4) of this condition.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2) (condition 8.4.5.(1) ii.), documentation that the engine meets the emission standards.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4245(a); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (LPG)

8.4.7. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. *Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).*
[40 C.F.R. §60.4245(b); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (LPG)

8.5. Reporting Requirements

8.5.1. If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in §60.4243(d) (3)(i) (permit condition 8.1.13.), you must submit an annual report according to the requirements in paragraphs (1) through (3) of this condition.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(vii) Hours spent for operation for the purposes specified in §60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4. Beginning on February 26, 2025, submit annual report electronically according to ~~paragraph~~ 40 C.F.R. §60.4245(g) ~~of this section~~.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4245(e); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.2. Beginning on February 26, 2025, within 60 days after the date of completing each performance test, you must submit the results following the procedures specified in this condition. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or an alternate electronic file.

[40 C.F.R. §60.4245(f); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.3. If you are required to submit notifications or reports following the procedure specified in this condition, you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (1) and (2) of this condition. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described in

paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

[40 C.F.R. §60.4245(g); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.4. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (1) through (7) of this condition.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

[40 C.F.R. §60.4245(h); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.5. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (1) through (5) of this condition.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

[40 C.F.R. §60.4245(i); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.6. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[40 C.F.R. §60.4245(j); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.7. If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in 40 C.F.R. §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(vii) Hours spent for operation for the purposes specified in 40 C.F.R. §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in 40 C.F.R. §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 C.F.R. §60.4. Beginning on February 26, 2025, submit annual report electronically according to ~~paragraph~~ 40 C.F.R. §60.4214(g) ~~of this section~~.

[40 C.F.R. §60.4214(d); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.8. Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test required under this section following the procedures specified in paragraphs (1) and (2) of this condition.

(1) Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test. Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to condition 8.5.9. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test. The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to ~~paragraph (g) of this section~~condition 8.5.9.

[40 C.F.R. §60.4214(f); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.9. If you are required to submit notifications or reports following the procedure specified in this condition, you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (1) and (2) of this condition. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

[40 C.F.R. §60.4214(g); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.10. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (1) through (7) of this condition.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

[40 C.F.R. §60.4214(h); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.11. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (1) through (5) of this condition.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

[40 C.F.R. §60.4214(i); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.12. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[40 C.F.R. §60.4214(j); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.6. Compliance Plan

8.6.1. Reserved.

9.0 Landfill Building Furnace CB-325

9.1. Limitations and Standards

9.1.1. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.
[45CSR§2-3.1.]

9.1.2. Compliance with the visible emission requirements of subsection 3.1 (permit condition 9.1.1.) shall be determined in accordance with 40 CFR Part 60, Appendix A, Method 9 or by using measurements from continuous opacity monitoring systems approved by the Director. The Director may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of subsection 3.1. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.
[45CSR§2-3.2.]

9.1.3. **Exemption from 45CSR2 monitoring, testing, recordkeeping, and reporting**. Any fuel burning unit(s) having a heat input under ten (10) million B.T.U.'s per hour will be exempt from sections 4, 5, 6, 8 and 9 of 45CSR2. However, failure to attain acceptable air quality in parts of some urban areas may require the mandatory control of these sources at a later date.
[45CSR§2-11.1.]

9.2. Monitoring Requirements

9.2.1. At such reasonable times as the Director may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with condition 9.1.1. Method 9 shall be conducted in accordance with 40 CFR Part 60 Appendix A.
[45CSR§30-5.1.c.]

9.3. Testing Requirements

9.3.1. Reserved.

9.4. Recordkeeping Requirements

9.4.1. Reserved.

9.5. Reporting Requirements

9.5.1. Reserved.

9.6. Compliance Plan

9.6.1. Reserved.

APPENDIX A

45CSR2 & 45CSR10 Monitoring Plan

45 CSR 2 and 45 CSR 10
Monitoring and Recordkeeping Plan

Mitchell Plant

Facility Information:

Facility Name:Mitchell Plant

Facility Address: P.O. Box K
State Route 2
Moundsville, WV 26041

Facility Environmental Contact: Mr. G. M. (Matt) Palmer
Plant Environmental Coordinator

A. Facility Description:

Mitchell Plant is a coal-fired electric generating facility with two main combustion units (Units 1 and 2) discharging through a common stack shell that utilizes two separate stack discharge flues. Mitchell plant also has an auxiliary boiler (Aux. 1) that discharges through an independent auxiliary stack (Aux ML1). Unit 1, Unit 2, and Aux. Boiler 1 each have a design heat input greater than 10 mmBTU/hr making both 45 CSR 2A (Interpretive Rule for 45 CSR 2) and 45 CSR 10A (Interpretive Rule for 45 CSR 10) applicable to these sources.

I. 45 CSR 2 Monitoring Plan:

In accordance with Section 8.2.a of 45 CSR 2, following is the proposed plan for monitoring compliance with opacity limits found in Section 3 of that rule:

A. Main Stack (1E, 2E)

1. Applicable Standard:

   45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method(s):

   45 CSR 2, §3.2. *...Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emissions control.*

45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

a. Primary Monitoring Method: While a Continuous Opacity Monitoring System (COMS) would not be required on a wet scrubbed fuel burning unit, Mitchell Plant has chosen to employ COMS on each of the fuel burning units upstream of the wet scrubbers and located in plant ductwork. As such, the primary method of monitoring opacity at Mitchell Plant will be Continuous Opacity Monitors (COMS). The COMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75.

b. Other Credible Monitoring Method(s): While Mitchell Plant will use COMS as the primary method of monitoring opacity of the fuel burning units, we are also reserving the right to use other appropriate method that would produce credible data. These “other monitoring methods” will generally be used in the absence of COMS data or as other credible evidence used in conjunction with COMS data.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned**

45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

The applicable paragraphs for Mitchell Plant are the following:

§7.1.a.2: *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

§7.1.a.4: *For fuel burning unit(s) which burn only coal, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a daily basis and an ash and BTU analysis for each shipment.*

§7.1.a.6: *For fuel burning unit(s) which burn a combination of fuels, the owner or operator shall comply with the applicable Recordkeeping requirements of paragraph 7.1.a.1 through 7.1.a.5 for each fuel burned.*

The date and time of each startup and shutdown of Units 1 and 2 will be maintained. The quantity of coal burned on a daily basis as well as the ash and Btu content will also be maintained. From a fuel oil perspective, the quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

b. **Record Maintenance**

45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.

4. Exception Reporting:

a. **Particulate Mass Emissions:**

45 CSR 2A, §7.2.a. *With respect to excursions associated with measured emissions under Section 4 of 45CSR2, compliance with the reporting and testing requirements under the Appendix to 45CSR2 shall fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45CSR2.*

Mitchell Plant will comply with the reporting and testing requirements specified under the Appendix to 45 CSR 2.

b. **Opacity:**

45 CSR 2A, §7.2.b. *COMS – In accordance with the provisions of this subdivision, each owner or operator employing COMS as the method of monitoring compliance with opacity limits shall submit a "COMS Summary Report" and/or an "Excursion and COMS Monitoring System Performance Report" to the Director on a quarterly basis; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the fuel burning unit(s). All reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter. The COMS Summary Report shall contain the information and be in the format shown in Appendix B unless otherwise specified by the Director.*

45 CSR 2A, §7.2.b.1. *If the total duration of excursions for the reporting period is less than one percent (1%) of the total operating time for the reporting period and monitoring system downtime for the reporting period is less than five percent (5%) of the total operating time for the reporting period, the COMS Summary Report shall be submitted to the Director; the Excursion and COMS Monitoring System Performance report shall be maintained on-site and shall be submitted to the Director upon request.*

45 CSR 2A, §7.2.b.2. *If the total duration of excursions for the reporting period is one percent (1%) or greater of the total operating time for the reporting period or the total monitoring system downtime for the reporting period is five percent (5%) or greater of the total operating time for the reporting period, the COMS Summary Report and the Excursion and COMS Monitoring System Performance Report shall both be submitted to the Director.*

45 CSR 2A, §7.2.b.3. *The Excursion and COMS Monitoring System Performance Report shall be in a format approved by the Director and shall include, but not be limited to, the following information:*

45 CSR 2A, §7.2.b.3.A. *The magnitude of each excursion, and the date and time, including starting and ending times, of each excursion.*

45 CSR 2A, §7.2.b.3.B. *Specific identification of each excursion that occurs during start-ups, shutdowns, and malfunctions of the facility.*

45 CSR 2A, §7.2.b.3.C. *The nature and cause of any excursion (if known), and the corrective action taken and preventative measures adopted (if any).*

45 CSR 2A, §7.2.b.3.D. *The date and time identifying each period during which quality- controlled monitoring data was unavailable, except for zero and span checks, and the reason for data unavailability and the nature of the repairs or adjustments to the monitoring system.*

45 CSR 2A, §7.2.b.3.E. *When no excursions have occurred or there were no periods of quality-controlled data unavailability, and no monitoring systems were inoperative, repaired, or adjusted, such information shall be stated in the report.*

Attached, as Appendices A and B are sample copies of a typical COMS "Summary Report" and "Excess opacity and COM downtime report" that we plan on using to fulfill the opacity reporting requirements. The COMS "Summary Report" will satisfy the conditions under 45 CSR 2A, §7.2.b for the "COMS Summary Report" and will be submitted to the Director according to its requirements. The "Excess opacity and COM downtime report" satisfies the conditions under 45 CSR 2A, §7.2.b.3. for the "Excursion and COMS Monitoring System Performance Report". The "Excess opacity and COM downtime report" shall be submitted to the Director following the conditions outlined in 45 CSR 2A, §7.2.b.1. and §7.2.b.2.

To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

Aux. Stack (Aux ML1)

1. Applicable Standard:

   45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method:

   45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

   45 CSR 2, §8.4.a. *The owner or operator of a fuel burning unit(s) may petition for alternatives to testing, monitoring, and reporting requirements prescribed pursuant to this rule for conditions, including, but not limited to, the following:*

   45 CSR 2, §8.4.a.1. *Infrequent use of a fuel burning unit(s)*

   Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack. Based on limited operating hours, the requirement for COMS installation per Section 6.2.a of interpretive rule 45 CSR 2A was determined to be overly-burdensome and sufficient reason for the granting of alternative monitoring methods. The alternative monitoring method based on USEPA Method 9 visible emission readings is described below.

   - Primary Monitoring Method: As an alternative to COMS monitoring, a Method 9 reading will be conducted one time per month provided the following conditions are met: 1) The auxiliary boiler has operated at normal, stable load conditions for at least 24 consecutive hours and 2) weather/lighting conditions are conducive to taking proper Method 9 readings. Since the Mitchell auxiliary boiler does not utilize post-combustion particulate emissions controls, operating parameters of control equipment are nonexistent and therefore unable to be monitored.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned**

45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

The applicable paragraph for the Mitchell Plant auxiliary boilers follows:

§7.1.a.2: *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

As such, the date and time of each startup and shutdown of the auxiliary boiler will be maintained. The quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

b. **Record Maintenance**

45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. In the case of the auxiliary boilers, strip chart recordings, etc. are generally not available.

4. Exception Reporting:

Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack.

a. **Particulate Mass Emissions** – As an alternative to the testing and exception reporting requirements for particulate mass emissions from the auxiliary boiler, the following was previously proposed and approved. Based on an average heat content of approximately 139,877 Btu/gallon (calendar year 2000 data) and an AP-42 based particulate mass emissions emission factor of 2 lbs/thousand gallons, the calculated particulate mass emissions of the auxiliary boiler are 0.01 lb/mmBTU. As such, the fuel analysis records maintained under the fuel quality analysis and recordkeeping section of this plan provide sufficient evidence of compliance with the particulate mass emission limit. For the purpose of meeting exception reporting requirements, any fuel oil analysis indicating a heat content of less than 25,000 Btu per gallon will be reported to the OAQ to fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45 CSR 2 – 45 CSR 2A, §7.2.a. A heat content of 25,000 Btu/gal and a particulate emissions factor of 2 lbs/thousand gallons would result in a calculated particulate mass emissions of approximately 90% of the applicable 45 CSR 2 standard.

b. **Opacity** – As an alternative to the exception reporting requirements for opacity emissions from the auxiliary boiler, the following was previously proposed and approved. We will maintain a copy of each properly conducted (correct weather/lighting conditions, etc.) Method 9 evaluation performed. Any properly conducted Method 9 test which indicates an exceedance shall be submitted to the OAQ on a quarterly basis (within 30 days of the end of the quarter) along with an accompanying description of the excursion cause, any corrective action taken, and the beginning and ending times for the excursion.

To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

If no exceptions have occurred during the quarter, then a report will be submitted to the OAQ stating so. This will identify periods in which no method 9 tests were conducted (e.g. unit out of service) or when no fuel oil was received.

II. <u>45 CSR 10 Monitoring Plan:</u>

In accordance with Section 8.2.c of 45 CSR 10, following is the proposed plan for monitoring compliance with the sulfur dioxide weight emission standards expressed in Section 3 of that rule:

A. Main Stack (1E, 2E)

1. Applicable Standard:

45 CSR 10, §3.1.b. *For fuel burning units of the Mitchell Plant of Kentucky/Wheeling Power Company, located in Air Quality Control Region I, the product of 7.5 and the total actual operating heat inputs for such units discharging through those stacks in million BTU's per hour.*

45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

A new SO_2 limit will likely be established as a result of the installation of the flue gas desulfurization system/new stack configuration and the subsequent NAAQS compliance demonstration modeling. Assuming that revised SO2 limit is more stringent than the current limit expressed in 45 CSR 10, Mitchell Plant SO_2 emissions will be regulated by the more stringent of the two limits.

2. Monitoring Method:

45 CSR 10, §8.2.c.1. *The installation, operation and maintenance of a continuous monitoring system meeting the requirements 40 CFR Part 60, Appendix B, Performance Specification 2 (PS2) or Performance Specification 7 (PS7) shall be deemed to fulfill the requirements of a monitoring plan for a fuel burning unit(s), manufacturing process source(s) or combustion source(s). CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS2.*

a. Primary Monitoring Method: The primary method of monitoring SO_2 mass emissions from the two new stack flues (located within one stack shell) will be Continuous Emissions Monitors (CEMS). Data used in evaluating the performance of the Mitchell Units with the applicable standard will be unbiased, unsubstituted data as specified in definition 45 CSR 10A, §6.1.b.1. Data capture of more than 50% constitutes sufficient data for the daily mass emissions to be considered valid. The CEMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75. Because Units 1 and 2 will discharge through separate flues and both units are "Type a" fuel burning units as defined in 45 CSR 10, the plant-wide limit is calculated by summing the limits from the two flues.

b. Other Credible Monitoring Method(s): While Mitchell Plant will use CEMS as the primary method of monitoring SO_2 mass emissions from the two flues, we are also reserving the right to use other appropriate methods that would produce credible data. These "other monitoring methods" will generally be used in the absence of CEMS data or as other credible evidence used in conjunction with CEMS data.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned:**

45 CSR 10A, §7.1.a. *Fuel burning units - The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule and the quality or quantity of fuel burned in each unit…*

45 CSR 10A, §7.1.c. *The owner or operator of a fuel burning unit or combustion source which utilizes CEMS shall be exempt from the provisions of subdivision 7.1.a. or 7.1.b, respectively.*

As such, Mitchell plant will not maintain records of the operating schedule and the quality and quantity of fuel burned in each unit for purposes of meeting the requirements for a monitoring plan under 45 CSR 10. While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

b. **Record Maintenance**

45 CSR 10A, §7.1.d. *For fuel burning units, manufacturing process sources, and combustion sources, records of all required monitoring data as established in an approved monitoring plan and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

As such, CEMS records at Mitchell Plant will be maintained for at least five years.

4. Exception Reporting:

45 CSR 10A, §7.2.a. *CEMS - Each owner or operator employing CEMS for an approved monitoring plan, shall submit a "CEMS Summary Report" and/or a "CEMS Excursion and Monitoring System Performance Report" to the Director quarterly; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the source. All reports shall be postmarked no later than forty-five (45) days following the end of each calendar quarter. The CEMS Summary Report shall contain the information and be in the format shown in Appendix A unless otherwise specified by the Director.*

45 CSR 10A, §7.2.a.1. *Submittal of 40 CFR Part 75 data in electronic data (EDR) format to the Director shall be deemed to satisfy the requirements of subdivision 7.2.a.*

As such, Mitchell Plant will submit the 40 CFR 75 quarterly electronic data reports (EDRs) to the OAQ to meet the requirements for a CEMS Summary Report and the CEMS Excursion and Monitoring System Performance Report. The EDR reports will be submitted to the OAQ no later than 45 days following the end of the quarter.

When no excursions of the 24-hour SO_2 standard have occurred, such information shall be stated in the cover letter of the EDR submittal.

B. Aux. Stack (Aux ML1)

1. Applicable Standard:

45 CSR 10, §3.1.e. *For type 'b' and Type 'c' fuel burning units, the product of 3.1 and the total* *design heat inputs for such units discharging through those stacks in million BTU's per hour.*

45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

2. Monitoring, Recordkeeping, Exception Reporting Requirements:

45 CSR 10, §10.3. *The owner or operator of a fuel burning unit(s) which combusts natural gas, wood or distillate oil, alone or in combination, shall be exempt from the requirements of section 8.*

As such, the Mitchell Plant auxiliary boiler (auxiliary stack) is exempt from Testing, Monitoring, Recordkeeping, and Reporting requirements found in 45 CSR 10, Section 8 because the fuel burning source combusts only distillate oil. 45 CSR 10, Section 8 also contains the requirement for the development of a monitoring plan. The simple nature of burning distillate oil results in an SO2 emission rate well below the standard.

While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

Revisions of Monitoring Plan:

Mitchell Plant reserves the right to periodically revise the conditions of this monitoring plan. Any revised plan will become effective only after approval by the OAQ.

Implementation of Revised Monitoring Plan:

Implementation of this revised monitoring plan will occur in concurrence with the installation and operation of the new stack for Units 1 and 2 at Mitchell Plant.

SUMMARY REPORT

Pollutant: **Opacity**
Company: American Electric Power
Philip Sporn Plant

Emmission Limitation

Regulation	Limit	Units	Period
45 CSR 2	10	%	6 minute average

Total source Operating Time 132,361 minutes

Reporting Period: Calendar Quarter 10/1/00 to 12/31/00
Monitor Manufacturer : United Sciences, Inc.
Model Number: 500C
Date of last Certification or Audit: 11/28/00
Process Unit(s) Description: Units 1-4 Stack,
Four coal fired power generation units attached to a common stack (CS014).

Emissions Data Summary

1. Duration of excess emissions in reporting period due to:

	45 CSR 2
a. Startup / Shutdown	1206 minutes
b. Soot Blowing	0 minutes
c. Malfunction due to Control Equipment Problems	96 minutes
d. Malfunction due to Process Problem	12 minutes
e. Other Known Causes	0 minutes
f. Unknown Causes	0 minutes
2. Total Duration	1314 minutes
3. Percent Excess Emission	0.99 %

% Excess = 100 * (Total Duration / Total Source Operating Time)

COMS Performance Summary

1. COMS Downtime in reporting period due to:

a. Monitor Equipment Malfunction	66 minutes
b. Other Equipment Malfunction	0 minutes
c. Quality Assurance Calibration	1170 minutes
d. Other Known Causes	0 minutes
e. Unknown Causes	0 minutes
2. Total COMS Downtime	1236 minutes
3. Percent COMS Downtime	0.93 %

% Downtime = 100 * (Total COMS Downtime / Total Source Operating Time)

Please Note:

1. Separate Summary Reports are required for each boiler in the system when it has separate monitoring equipment.
2. Total source operating time means the total time which affected source is operating, including all periods of start-up, shut-down, malfunction, soot blowing, or COMS downtime as those terms are defined under the rule.
3. All times for opacity must be reported in minutes.
4. On a separate page describe any changes since the last reporting period to the COMS process or controls.
5. Other reports may be necessary to meet requirements.

Appendix A
Sample

EXCESS OPACITY AND COM DOWNTIME REPORT

Page: 1

Facility Name: PHILIP SPORN
Address: P.O. BOX 389
New Haven, WVa 25265

Report Period: 10/01/00 to 12/31/00
Emission Limit: 10.499

Stack/Unit ID: CS014

Parameter Name: OPACSQA

Appendix B
Sample

Date	Start Time	End Time	Duration (Minutes)	Average Opacity	Maximum Opacity	Causes/ Corrective Action
10/01/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/02/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/03/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/04/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/05/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/06/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/07/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/08/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/09/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/10/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/10/00	0606	0618	12	11	11	TR Set Trip Reset TR
10/10/00	0636	0642	6	11	11	TR Set Trip Reset TR
10/10/00	0824	0836	12	11	11	TR Set Trip Reset TR
10/11/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/11/00	1130	1224	54	-	-	COM Repair, COM o/s COM Lens Cleaned
10/12/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/13/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/14/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/15/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/16/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/16/00	1448	1454	6	15	15	Unit Tripped None

* = Time period does not end during selected time range

APPENDIX B

Certification of Data Accuracy

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 and 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 USEPA); or

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

APPENDIX C

DAQ letter dated September 3, 2002 regarding Thermal Decomposition of Boiler Cleaning Solution

Division of Air Quality
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943
Telephone Number: (304) 926-3647
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West Virginia Department of Environmental Protection

Bob Wise
Governor

Michael O. Callaghan
Cabinet Secretary

Mr. Greg Wooten
Senior Engineer
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373

September 3, 2002

Dear Mr. Wooten:

RE: Thermal Decomposition of Boiler Cleaning Solution at AEP Facilities (i.e. Kammer, Mitchell, Mountaineer, Philip Sporn, Amos or Kanawha River Plants)

Based on the information you provided by email dated August 19, 2002, subsequent phone conversations, and email dated September 3, 2002, (copies attached) the Division is granting approval for AEP to thermally decompose boiler cleaning solution in the boilers at the AEP facilities identified above.

The DAQ is granting approval for AEP to thermally decompose boiler cleaning solution at the AEP facilities identified above, on an as needed and pre-approved basis, subject to the DAQ notification requirements, as outlined in the attached document titled "American Electric Power Boiler Chemical Cleaning Process Evaporation Notification Procedure", as revised.

If you have any questions regarding this matter please contact Laura Mae Crowder of my staff at (304) 926-3647.

Sincerely,

Jesse D. Adkins
Assistant Director of Enforcement
Division of Air Quality

cc: file

West Virginia Department of Environmental Protection "Promoting a healthy environment."

AMERICAN ELECTRIC POWER
BOILER CHEMICAL CLEANING PROCESS
EVAPORATION NOTIFICATION PROCEDURE

Step 1. The spent boiler chemical cleaning process liquid will be collected and stored on site in temporary (frac) tanks and/or permanently installed Metal Cleaning storage tanks. One sample will be collected for laboratory analysis from each storage tank, unless the tanks were manifolded together such that a number of tanks were filled simultaneously, resulting in the co-mingling of the solution in those tanks; in which case, one representative sample may be collected from each group of tanks that were manifolded together. The analyses from the tanks will be used to determine the hazard characteristics of the total volume of material.

Step 2. Upon receipt and assessment of the laboratory TCLP analyses, the hazard characteristics of the spent cleaning solution will be determined. Upon being confirmed non-hazardous, the "AEP facility" (i.e. Kammer, Mitchell, Mountaineer, Philip Sporn, Amos, or Kanawha River Plant) will proceed with the process to thermally decompose (evaporate) the spent material in a boiler on site.

Step 3. The AEP facility will notify West Virginia DAQ by telephone, facsimile or email on or before the day of scheduled commencement for the evaporation of the non-hazardous spent cleaning solution. AEP will submit via facsimile to the Compliance and Enforcement Section of the DAQ, a minimum of one (1) business day prior to commencement of the thermal decomposition process, the following information:

- The results of the laboratory TCLP analyses
- The volume of spent cleaning solution to be evaporated
- The designated boiler(s) in which the spent cleaning solution will be evaporated
- The expected schedule for completing the process

Step 4. AEP will perform evaporation of the spent cleaning solution in the designated boiler(s) in accordance with the appropriate chemical cleaning process document (e.g. "Kammer/Mitchell Plant Chemical Cleaning Process") and this notification procedure.

APPENDIX D

DAQ letter dated January 21, 2004 regarding Demineralizer Resin Burn

Division of Air Quality
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943
Telephone Number: (304) 926-3647
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West Virginia Department of Environmental Protection

Bob Wise
Governor

Stephanie R. Timmermeyer
Cabinet Secretary

Mr. Frank Blake
Engineer – Environmental Services
American Electric Power
1 Riverside Plaza – Floor 22
Columbus, Ohio 43215-2373

January 21, 2004

Dear Mr. Blake:

RE: Demineralizer Resin Burn at AEP Facilities (i.e. John Amos, Kammer, Mitchell, Mountaineer, Philip Sporn, or Kanawha River Plants)

Based on the information you provided during phone conversations on November 14, 2003 as well as by paper mail on November 25, 2003, the Division of Air Quality (DAQ) is granting approval for AEP to burn demineralizer resin in the boilers at the AEP facilities identified above.

The DAQ is granting approval for AEP burn demineralizer resin at the AEP facilities identified above on an as needed and pre-approved basis, subject to the DAQ notification requirements, as outlined in the document titled "American Electric Power Demineralizer Resin Burn Notification Procedure" as revised.

If you have any questions regarding this matter please contact Michael Rowe of my staff at (304) 926-3647.

Sincerely,

Jesse D. Adkins
Assistant Director of Enforcement
Division of Air Quality

cc: file
M. Dorsey, DWWM

West Virginia Department of Environmental Protection "Promoting a healthy environment."

AMERICAN ELECTRIC POWER DEMINERALIZER RESIN BURN NOTIFICATION PROCEDURE

Step 1. An appropriate number of samples representative of the used demineralizer resin to be consumed in the boiler will be collected for laboratory analysis to determine the hazard characteristics of the total volume of the material. Analysis will be completed using ASTM approved methods and by a WV Department of Environmental Protection certified laboratory.

Step 2. Upon receipt and assessment of the laboratory TCLP analysis, the hazard characteristics of the used demineralizer resin will be determined. Upon being confirmed as non-hazardous, the AEP facility will proceed to notify the West Virginia DAQ of the intent to burn the demineralizer resin. If the material is determined to be hazardous, it must be disposed of in accordance with 33CSR20 "Hazardous Waste Management Rule". Questions concerning this rule should be directed to the Division of Water and Waste Management (DWWM) at 304 558-5989.

Step 3. The AEP facility will notify the West Virginia DAQ by telephone, facsimile or email at least one business day before the scheduled commencement for the burn of the non-hazardous demineralizer resin. AEP will submit via facsimile to the Compliance and Enforcement Section of the DAQ, a minimum of one (1) business day prior to commencement of the demineralizer resin burn, the following information:

- The results of the laboratory TCLP analyses
- The volume and/or amount of demineralizer resin to be burned
- The designated boiler(s) in which the demineralizer resin will be burned.
- The expected schedule with beginning and end dates and times for completing the process
- The notification will be formatted with a subject line clearly defining the purpose of the notification and the facility where the resin will be burned.

Step 4. AEP will perform the demineralizer resin burn in the designated boiler(s) in accordance with the submitted notification. AEP will maintain records on site of all demineralizer resin burned. These records will include the date, time, boiler, load condition, volume/amount of resin and TCLP analysis.

APPENDIX E

Cross-State Air Pollution Rule (CSAPR) Requirements

Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements

Plant Name: Mitchell Plant	West Virginia ID Number: 051-00005	ORIS/Facility Code: 3948

1. Owners and operators of the CSAPR subject unit(s) identified in the CSAPR Monitoring Requirements Table below are subject to the requirements of the *CSAPR NO_X Annual Trading Program Requirements, CSAPR NO_X Ozone Season Group 2 Trading Program Requirements, and the CSAPR SO_2 Group 1 Trading Program Requirements* in Appendix ~~A~~ E to this permit.

2. Owners and operators of the CSAPR subject unit(s) identified in the CSAPR Monitoring Requirements Table below are subject to the monitoring requirements specified in the table below.

CSAPR MONITORING REQUIREMENTS TABLE			
Description of Monitoring Requirements:	**Parameter**		
Unit ID: Unit 1, Unit 2	**SO_2**	**NO_X**	**Heat Input**
Continuous emission monitoring system (CEMS) pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	X	X	X
Excepted monitoring system pursuant to 40 CFR part 75, appendix D (*Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units*)			
Excepted monitoring system pursuant to 40 CFR part 75, appendix E (*Optional NO_X Emissions Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units*)			
Low Mass Emissions excepted monitoring (LME) pursuant to 40 CFR 75.19 (*Optional SO_2, NO_X, and CO_2 Emissions Calculation for Low Mass Emissions (LME) Units*)			
EPA-approved alternative monitoring system pursuant to 40 CFR part 75, subpart E			

3. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435, (*CSAPR NO_X Annual Trading Program),* 97.830 through 97.835 *(CSAPR NO_X Ozone Season Group 2 Trading Program) and,* 97.630 through 97.635 *(CSAPR SO_2 Group 1 Trading Program)*. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading program.

4. Owners and operators shall submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable.

5. Owners and operators that want to use an alternative monitoring system shall submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E, 40 CFR 75.66, and the applicable trading program provisions found in 40 CFR *97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program) and, 97.635 (CSAPR SO_2 Group 1 Trading Program)*. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at https://www.epa.gov/airmarkets/complete-list-responses-40-cfr-part-75-petitions.

6. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR *97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program) and/or, 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program)* shall submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and *97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program) and/or 97.635 (CSAPR SO_2 Group 1 Trading Program)*. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at https://www.epa.gov/airmarkets/complete-list-responses-40-cfr-part-75-petitions.

CSAPR NO_X Annual Trading Program requirements (40 CFR 97.406)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general monitoring, recordkeeping, and reporting requirements, including: installation, certification, and data accounting; compliance deadlines; reporting data; prohibitions; and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including: monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Annual emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source exceed the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) CSAPR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for West Virginia and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying:

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in West Virginia for such control period, by which each common designated representative's share of such

NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of CSAPR NO_X Annual allowances held for compliance.

(i). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A CSAPR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart AAAAA, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) Owners and operators shall not be required to revise the title V permit for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA.

(2) Owners and operators shall revise the title V permit for any addition of, or change to, a unit's description in the

CSAPR Monitoring Requirements Table above. The addition of, or change to, a unit's description of whether a unit is required to monitor and report NOx emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.430 through 97.435 is eligible for minor permit modification procedures in accordance with 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.

(2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR NO_X Ozone Season Group 2 Trading Program Requirements (40 CFR 97.806)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general monitoring, recordkeeping, and reporting requirements, including: installation, certification, and data accounting; compliance deadlines; reporting data; prohibitions; and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including: monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Ozone Season Group 2 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source exceed the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NO_X Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and

(B). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(2) CSAPR NO_X Ozone Season Group 2 assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for West Virginia and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X

emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in West Virginia for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Ozone Season Group 2 Trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart EEEEE or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(ii). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(4) Vintage of CSAPR NO_X Ozone Season Group 2 allowances held for compliance.

(i). A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart EEEEE.

(6) Limited authorization. A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and (ii). Notwithstanding any other provision of 40 CFR part 97, subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) Owners and operators shall not be required to revise the title V permit for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart EEEEE.

(2) Owners and operators shall revise the title V permit for any addition of, or change to, a unit's description in the CSAPR Monitoring Requirements Table above. The addition of, or change to, a unit's description of whether a unit is required to monitor and report NOx emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.830 through 97.835 is eligible for minor permit modification procedures in accordance with 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart EEEEE.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR SO_2 Group 1 Trading Program requirements (40 CFR §97.606)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general monitoring, recordkeeping, and reporting requirements, including: installation, certification, and data accounting; compliance deadlines; reporting data; prohibitions; and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including: monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) CSAPR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source exceed the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) CSAPR SO_2 Group 1 assurance provisions.

(i). If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for West Virginia and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in West Virginia for such control period, by which each common designated representative's share of such SO_2

emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of CSAPR SO_2 Group 1 allowances held for compliance.

(i). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) Owners and operators shall not be required to revise the title V permit for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) Owners and operators shall revise the title V permit for any addition of, or change to, a unit's description in the

CSAPR Monitoring Requirements Table above. The addition of, or change to, a unit's description of whether a unit is required to monitor and report NOx emissions using a continuous emission monitoring system (under subpart B of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.630 through 97.635 is eligible for minor permit modification procedures in accordance with 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

APPENDIX F

Acid Rain Permit

west virginia department of environmental protection
Division of Air Quality

Phase II Acid Rain Permit

Plant Name: **Mitchell Power Station**		Permit #: **R33-3948-2027-6**
Affected Unit(s): **1, 2**		
Operator: **Kentucky Power Company**		ORIS Code: **3948**
Effective Date	From: **January 1, 2023**	To: **December 31, 2027**

Contents:

1. Statement of Basis.

2. SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3. Comments, notes and justifications regarding permit decisions and changes made to permit application forms during the review process, and any additional requirements or conditions.

4. The permit application forms submitted for this source, as corrected by the West Virginia Division of Air Quality. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

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1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with W. Va. Code §22-5-4(a)(16) and Titles IV and V of the Clean Air Act, the West Virginia Department of Environmental Protection, Division of Air Quality issues this permit pursuant to 45CSR33 and 45CSR30.

Permit Approval

Laura M. Crowder Digitally signed by: Laura M. Crowder DN: CN = Laura M. Crowder email = Laura.M.Crowder@wv.gov C = US O = West Virginia Department of Environmental Protection OU = Division of Air Quality Date: 2022.12.19 12:21:39 -05'00'

December 19, 2022

Laura M. Crowder, Director
Division of Air Quality

Date

West Virginia Department of Environmental Protection • Division of Air Quality

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No. **1**

SO_2 Allowances	Year				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	18995	18995	18995	18995	18995
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A

The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).

NO_x Requirements	2023	2024	2025	2026	2027
NO_x Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50

Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers.

In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

West Virginia Department of Environmental Protection • Division of Air Quality

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No. **2**

SO_2 Allowances	**Year**				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	19656	19656	19656	19656	19656
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A

The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).

NO_x Requirements	**2023**	**2024**	**2025**	**2026**	**2027**
NO_x Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50

Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers.

In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/31/2021

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☑ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Mitchell (WV)	West Virginia	3948

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Mitchell (WV)
Facility (Source) Name (from STEP 1)

Acid Rain - Page 2

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
 (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
 (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
 (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
 (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
 (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
 (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
 (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
 (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

Acid Rain - Page 4

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Scott A. Weaver

Signature Scott A Weaver

Date 4/7/2022

EPA

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain NOx Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

Page 1

This submission is: ☐ New ☑ Revised

Page 1 of 2

STEP 1
Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

Plant Name	State	Plant Code
Mitchell	WV	3948

STEP 2

Identify each affected Group 1 and Group 2 boiler using the unit IDs from the current Certificate of Representation covering the facility. Also indicate the boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom, and select the compliance option for each unit by making an 'X' in the appropriate row and column.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	X	X				
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)						
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)						
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)						
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						

EPA Form 7610-28 (Revised 7-2014)

NOx Compliance – Page 2

STEP 2, cont'd

Plant Name (From Step 1)	Mitchell

	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(i) NO_x Averaging Plan (include NO_x Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form))						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						

STEP 3: Identify the first calendar year in which this plan will apply.

January 1, 2019

STEP 4: Read the special provisions and certification, enter the name of the designated representative, sign and date.

Special Provisions

General. This source is subject to the standard requirements in 40 CFR 72.9. These requirements are listed in this source's Acid Rain Permit.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Scott A. Weaver	
Signature	Scott A Weaver	Date 12-18-18

EPA Form 7610-28 (Revised 7-2014)

~~APPENDIX G~~

~~Class II General Permit Registration~~
~~G60-C057A~~

West Virginia Department of Environmental Protection

Joe Manchin, III
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Class II General Permit
G60-C Registration to Modify

for the
Prevention and Control of Air Pollution in regard to the
Construction, Modification, Relocation, Administrative Update and
Operation of Emergency Generators

The permittee identified at the facility listed below is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of General Permit G60-C.

G60-C057A

Issued to:

AEP Generation Resources Inc.
Mitchell Plant
051-00005

William F. Durham
Director

Issued: August 8, 2014

This Class II General Permit Registration will supercede and replace G60-C057.

Facility Location:	State Route 2, Moundsville, Marshall County, West Virginia
Mailing Address:	P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generation Facility
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Registration Type:	Modification
Description of Change:	Installation of two additional generators (EG-1 and EG-2) to black start the facility.

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 or registration 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.

Unless otherwise stated WVDEP DAQ did not determine whether the permittee is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart ZZZZ.

All registered facilities under Class II General Permit G60-C are subject to Sections 1.0, 2.0, 3.0, and 4.0.

The following sections of Class II General Permit G60-C apply to the registrant:

Section 5	Reciprocating Internal Combustion Engines (R.I.C.E.)	X
Section 6	Tanks	X
Section 7	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40CFR60 Subpart IIII)	X
Section 8	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (40CFR60 Subpart JJJJ)	X

Emission Units

Emission Unit ID	Emission Unit Description (Make, Model, Serial No.)	Year Installed	Design Capacity (Bhp/rpm)
LPG	Generac SG080, 127 BHP Engine (Spark Ignition Engine)	2013	127/1,800
EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	2014	3,717/1,800
EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	2014	3,004/1,800

Emission Limitations

Source ID#	Nitrogen Oxides		Carbon Monoxide		Volatile Organic Compounds	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
LPG	0.74	0.19	21.75	5.44	0.22	0.06
EG-1	59.9	14.98	7.66	1.92	0.94	0.24
EG-2	36.4	9.1	4.85	1.21	1.18	0.03
TOTAL	97.04	24.27	34.26	8.57	2.34	0.33

West Virginia Department of Environmental Protection
Division of Air Quality

Fact Sheet

For Draft/Proposed Renewal Permitting Action Under 45CSR30 and Title V of the Clean Air Act

Permit Number: **R30-05100005-2025**
Application Received: **May ~~19~~9, 2024**
Plant Identification Number: **03-054-05100005**
Permittee: **Kentucky Power Company**
Facility Name: **Mitchell Plant**
Mailing Address: **1 Riverside Plaza, Columbus, Ohio 43215-2373**

Physical Location:	Cresap/Moundsville, Marshall County, West Virginia
UTM Coordinates:	516.00 km Easting • 4409.00 km Northing • Zone 17
Directions:	From Charleston take Interstate 77 North to Exit 179. Travel north on US Route 2 approximately 70 miles to Cresap. Facility is located on Route 2 approximately nine (9) miles south of Moundsville, WV.

Facility Description

The Mitchell Plant is a fossil fuel fired electric generation facility and operates under Standard Industrial Classification (SIC) code 4911. The facility consists of two (2) coal-fired steam generators with a rated design capacity of 7,020 mmBtu/hr each, one (1) oil-fired auxiliary boiler with a rated design capacity of 663 mmBtu/hr, one diesel emergency generator rated for 3,717 hp, one diesel emergency generator rated for 3,004 hp, one diesel emergency generator rated for 464 hp, one diesel emergency generator rated for 513 hp and various supporting operations such as coal and ash handling, limestone handling, and various tanks with insignificant emissions. The facility has the potential to operate seven (7) days per week, twenty-four (24) hours per day and fifty-two (52) weeks per year.

This renewal permit also incorporates minor modifications R30-05100005-2019 MM02, MM03 and MM04. The purpose of minor modification MM02 is to add a 2023 Cummins QSG12 513 hp diesel emergency generator LF DEG2 and a 600 gallon diesel fuel storage tank LF DEGT2. The purpose of minor modification MM03 is to replace the existing 1971 230 hp diesel emergency generator 17S with a 2023 Cummins CFP7E-F60 249 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #28 with a new 300 gallon diesel fuel tank. The purpose of MM04 is to replace the existing 1971 230 hp diesel emergency generator 18S with a 2024 Cummins

CFP9E-F10 275 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #29 with a new 300 gallon diesel fuel tank.

Emissions Summary

Plantwide Emissions Summary [Tons per Year]

Regulated Pollutants	Potential Emissions [1]	2023 Actual Emissions [2]
Carbon Monoxide (CO)	4,743.23	365.41
Nitrogen Oxides (NO_X)	36,332.05	1,587.76
Particulate Matter ($PM_{2.5}$)	1,096.2	21.94
Particulate Matter (PM_{10})	3,169.0	47.69
Total Particulate Matter (TSP)	5,423.79	134.40
Sulfur Dioxide (SO_2)	89,743.04	1193.52
Volatile Organic Compounds (VOC)	559.82	43.30

PM_{10} is a component of TSP.

Hazardous Air Pollutants [3]	Potential Emissions [1]	2023 Actual Emissions [2]
Hydrogen Chloride	12,337	6.54
Hydrogen Fluoride	1,071	5.98
Selenium	48.45	0.48
Manganese	3.77	0.04
Nickel	1.69	0.04
Arsenic	5.62	0.02
Mercury compounds	2.13	0.01
Beryllium	13.37	~~0.0013~~0.01
Chromium	2.00	0.04
Cobalt	0.74	0.01
Lead	3.65	0.02

[1] The potential emissions are from the renewal application.
[2] Actual emissions are from the State and Local Emission Inventory System (SLEIS) Summary Report Total Emissions by Source.
[3] Some of the above HAPs may be counted as PM or VOCs.

Title V Program Applicability Basis

This facility has the potential to emit 4,743.23 tpy of CO; 36,332.05 tpy of NO_X; 3,169.0 tpy of PM_{10}; 89,743.04 tpy of SO_2; 559.82 tpy of VOC; 12,337 tpy of HCl; 1,071 tpy of HF; 48.45 tpy of Selenium; and 13.37 tpy of Beryllium. Due to this facility's potential to emit over 100 tons per year of criteria pollutant, over 10 tons per year of a single HAP, and over 25 tons per year of aggregate HAPs, Kentucky Power Company’s Mitchell Plant is required to have an operating permit pursuant to Title V of the Federal Clean Air Act as amended and 45CSR30.

Legal and Factual Basis for Permit Conditions

The State and Federally-enforceable conditions of the Title V Operating Permits are based upon the requirements of the State of West Virginia Operating Permit Rule 45CSR30 for the purposes of Title V of the Federal Clean Air Act and the underlying applicable requirements in other state and federal rules.

This facility has been found to be subject to the following applicable rules:

Federal and State:	45CSR2	Control of particulate matter emissions from indirect heat exchangers
	45CSR2A	Testing and MRR requirements under 45CSR2
	45CSR6	Open burning prohibited.
	45CSR10	Control of sulfur dioxide emissions from indirect heat exchangers
	45CSR10A	Testing and MRR requirements under 45CSR10
	45CSR11	Standby plans for emergency episodes.
	45CSR13	Permits for construction/modification
	45CSR16	Standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60
	WV Code § 22-5-4 (a) (~~14~~15)	The Secretary can request any pertinent information such as annual emission inventory reporting.
	45CSR30	Operating permit requirement
	45CSR33	Acid Rain Provisions and Permits
	45CSR34	Emission Standards for HAPs for Source Categories Pursuant to 40 C.F.R. Parts 61 and 63
	45CSR43	Cross-State Air Pollution Rule
	40 C.F.R. Part 60 Subpart Db	Standards of Performance for Industrial–Commercial-Institutional Steam Generating Units
	40 C.F.R. Part 60 Subpart OOO	NSPS for Non-metallic mineral processing plants
	40 C.F.R. Part 60 Subpart IIII	NSPS for Compression Ignition IC Engines
	40 C.F.R. Part 60 Subpart JJJJ	NSPS for Spark Ignition IC Engines
	40 C.F.R. Part 61	Asbestos inspection and removal
	40 C.F.R. Part 63 Subpart ZZZZ	RICE MACT
	40 C.F.R. Part 63 Subpart DDDDD	Boiler MACT for Major Sources of HAP
	40 C.F.R. Part 63 Subpart UUUUU	Utility Mercury and Air Toxics (MATS) MACT
	40 C.F.R. Part 64	Compliance Assurance Monitoring
	40 C.F.R. Part 72	Permits Regulation
	40 C.F.R. Part 73	Sulfur Dioxide Allowance System Permits Regulation
	40 C.F.R. Part 74	Sulfur Dioxide Opt-ins
	40 C.F.R. Part 75	Continuous Emissions Monitoring
	40 C.F.R. Part 76	Nitrogen Oxides Reduction Program
	40 C.F.R. Part 77	Excess Emissions
	40 C.F.R. Part 78	Appeals Procedure for Acid Rain Program
	40 C.F.R. Part 82, Subpart F	Ozone depleting substances
	40 CFR Part 97, Subpart AAAAA	CSAPR NO_x Annual Trading Program
	40 CFR Part 97, Subpart EEEEE	CSAPR NO_x Ozone Season Group 2 Trading Program
	40 CFR Part 97, Subpart CCCCC	CSAPR SO_2 Group 1 Trading Program
State Only:	45CSR4	No objectionable odors.

WVDAQ Letter dated September 3, 2002 addressed to Mr. Greg Wooten and signed by Jesse D. Adkins regarding the thermal decomposition of boiler cleaning solutions.

WVDAQ Letter dated January 21, 2004 addressed to Mr. Frank Blake and signed by Jesse D. Adkins regarding the combustion of demineralizer resins.

Each State and Federally-enforceable condition of the Title V Operating Permit references the specific relevant requirements of 45CSR30 or the applicable requirement upon which it is based. Any condition of the Title V permit that is enforceable by the State but is not Federally-enforceable is identified in the Title V permit as such.

The Secretary's authority to require standards under 40 C.F.R. Part 60 (NSPS), 40 C.F.R. Part 61 (NESHAPs), and 40 C.F.R. Part 63 (NESHAPs MACT) is provided in West Virginia Code §§ 22-5-1 *et seq.,* 45CSR16, 45CSR34 and 45CSR30.

Active Permits/Consent Orders

Permit or Consent Order Number	Date of Issuance	Permit Determinations or Amendments That Affect the Permit *(if any)*
R13-2608E	May 12, 2014	
G60-C057A	August 8, 2014	
Phase II Acid Rain Permit # R33-3948-2027-6	December 19, 2022	

Conditions from this facility's Rule 13 permit(s) governing construction-related specifications and timing requirements will not be included in the Title V Operating Permit but will remain independently enforceable under the applicable Rule 13 permit(s). All other conditions from this facility's Rule 13 permit(s) governing the source's operation and compliance have been incorporated into this Title V permit in accordance with the "General Requirement Comparison Table," which may be downloaded from DAQ's website.

Determinations and Justifications

This is the fourth renewal of the Title V Permit. This renewal permit also incorporates minor modifications R30-05100005-2019 MM02, MM03 and MM04. The purpose of minor modification MM02 is to add a 2023 Cummins QSG12 513 hp diesel emergency generator LF DEG2 and a 600 gallon diesel fuel storage tank LF DEGT2. The purpose of minor modification MM03 is to replace the existing 1971 230 hp diesel emergency generator 17S with a 2023 Cummins CFP7E-F60 249 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #28 with a new 300 gallon diesel fuel tank. The purpose of MM04 is to replace the existing 1971 230 hp diesel emergency generator 18S with a 2024 Cummins CFP9E-F10 275 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #29 with a new 300 gallon diesel fuel tank.

The following changes have occurred since the most recent Title V permit was issued:

<u>Title V Permit Boilerplate changes:</u>

- **Condition 2.1.3.** – This condition was updated to delete the word "such" which was removed from 45CSR30 effective March 31, 2023. The citation was changed from "45CSR§30-2.12" to "45CSR§30-2.39" because the definition of "Secretary" was renumbered from a previous version of 45CSR30.

- **Condition 2.11.4** – The citation was changed from "45CSR§30-2.39" to "45CSR§30-2.40" because it was renumbered from a previous version of 45CSR30.

- **Conditions 2.17., 3.5.7. and 3.5.8.a.1.** – These conditions were deleted and replaced with "Reserved" because the emergency provisions under 45CSR§30-5.7 were removed from 45CSR30 effective March 31, 2023.

- **Condition 2.22.1** – "45CSR38" was removed from the citation because this rule has been repealed.

- **Conditions 3.1.6. and 3.3.1. –** The citation was revised to refer to the current version of the WV Code.

- **Condition 3.3.1.b. –** This condition was updated to include the following additional language: "If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit shall be revised in accordance with 45CSR§30-6.4~~.~~ or 45CSR§30-6.5 as applicable."

- **Condition 3.5.3.** – This condition was updated to include the current EPA mailing address.

- **Condition 3.5.4.** – This condition was updated because the requirement to submit a certified emissions statement was removed from 45CSR30 effective March 31, 2023.

- **Condition 3.5.8.a.2.** – This condition was updated to replace the word "telefax" with "email" according to the change in 45CSR30 effective March 31, 2023.

Updated Permit Language Due to Rule/Regulation Language Changes:

- **Conditions 4.0.1., 4.1.3., and 5.1.1.** – These conditions were deleted because they were deleted in 45CSR2 and 45CSR10.

- **Conditions 4.1.4.a., 4.1.5.a., 4.2.1., 4.2.3., 4.4.1., 4.4.2., 4.5.2. through 4.5.4. 5.1.3., 5.2.2. through 5.2.5., 5.4.1., 5.4.2., 5.5.1 through 5.5.3., and 5.5.6.** – The citations were revised based on revised numbering in 45CSR2 and 45CSR10.

- **Conditions 4.1.4.b., 4.1.9., 4.1.14., 4.2.12., 4.2.13., 4.2.15., 4.3.3., 4.3.12., 4.3.17. 4.4.6., 4.5.10. through 4.5.13** - These conditions were amended to match the revised 40 CFR 63 Subpart UUUUU.

- **Conditions 7.1.2., 7.1.6., 7.1.7., 7.4.2.** – ~~This~~ These conditions ~~was~~ were amended to match the revised 40 CFR ~~60~~ 63 Subpart ZZZZ.

- **Conditions 8.1.5., 8.1.7. through 8.1.9. and 8.5.7.** – These conditions were amended to match the revised 40 CFR 60 Subpart IIII.

- **Conditions 8.1.13., 8.4.6.(3) and 8.5.1.** – These conditions were amended to match the revised 40 CFR 60 Subpart JJJJ.

- **Conditions 8.5.2. through 8.5.6.** – These new conditions were added to match the revised 40 CFR 60 Subpart JJJJ.

- **Conditions 8.5.8. through 8.5.12.** – These new conditions were ~~amended~~ added to match the revised 40 CFR 60 Subpart IIII.

Changes requested in minor modification application R30-05100005~~1~~-2019 MM02:

- **Condition 1.1** – The Emission Units table was amended to add an entry for LF DEG2 and LF DEGT2.

- **Condition 8.0** – Diesel Driven Emergency Fire Pump Engine LF DEG2 was added to the list of emission units and emission point IDs in the title section.

- **Conditions 8.1.5. through 8.1.9., 8.2.1., 8.4.4., 8.5.7.** – LF DEG2 was added to the citation section of these existing conditions.

- **Condition 8.1.15.** – This requirement from ~~45 CSR~~40 CFR 63 Subpart ZZZZ was added for LF DEG2.

- **Conditions 8.5.8. through 8.5.12.** – New requirements from the revised Subpart IIII were added for LF DEG2.

Changes requested in minor modification application R30-05100005~~1~~-2019 MM03:

- **Condition 1.1** – The Emission Units table was amended to modify the entry for 17S to include the information for the new diesel emergency engine and for Tank #28 to include the information for the new diesel fire pump fuel tank.

- **Condition 7.0**. – The references to Emergency Diesel Driven Fire Pumps 17S and 18S were removed because the new replacement engines were moved to Section 8.0.

- **Condition 8.0** – Diesel Driven Emergency Fire Pump Engines 17E and 18E were added to the list of emission units and emission point IDs in the title section.

- **Condition 8.1.5.** – This requirement from 40 CFR 60 Subpart IIII was added for 17E.

- **Conditions 8.1.6. through 8.1.9., 8.1.14, 8.2.1., 8.4.4., 8.5.7.** – 17E was added to the citation section of these existing conditions.

- **Conditions 8.5.8. through 8.5.12.** – New requirements from the revised 40 CFR 60 Subpart IIII were added for 17E.

Changes requested in minor modification application R30-05100005~~1~~-2019 MM04:

- **Condition 1.1** – The Emission Units table was amended to modify the entry for 18S to include the information for the new diesel emergency engine and for Tank #29 to include the information for the new diesel fire pump fuel tank.

- **Condition 7.0**. – The references to Emergency Diesel Driven Fire Pumps 17S and 18S were removed because the new replacement engines were moved to Section 8.0.

- **Condition 8.0** – Diesel Driven Emergency Fire Pump Engines 17E and 18E were added to the list of emission units and emission point IDs in the title section.

- **Condition 8.1.5.** – This requirement from Subpart IIII was added for 18E.

- **Conditions 8.1.6. through 8.1.9., 8.1.14., 8.2.1., 8.4.4., 8.5.7.** – 18E was added to the citation section of these existing conditions.

- **Conditions 8.5.8. through 8.5.12.** – New requirements from the revised 40 CFR Subpart IIII were added for 18E.

Other Changes

- **Condition 4.3.1.** – The date for the next scheduled performance testing was updated.

- **Appendix F** – The current Acid Rain Permit R33-3948-2027-6 was included.

- **Appendix G** – The Class II General Permit Registration G60-C057A was deleted because the requirements are already included in Section 8.0.

Changes requested in renewal application R30-05100005~~1~~-2025:

- **Condition 1.1** – The Emission Units table was amended to delete Tank #44 and add Tanks #64 through #69.

Notes: In the renewal application, the company requested to remove the 2013 126 hp Generac SG080 LB4S liquid propane gas fired emergency generator LPG and the associated 500 gallon tank LPT from the Title V permit. However, these emission units are both permitted within NSR General Permit G60-C057A. Therefore, these sources cannot be removed until G60-C057A is modified to remove them.

Also, the company requested to increase the maximum annual amount of polymer and organsulfide to be delivered to the facility from 13,500 gal/yr to 25,000 gal/yr in the Title V permit. However, this annual throughput limit is permitted within NSR Permit R13-2608E. Therefore, this annual throughput limit cannot be changed until R13-2608E has been modified to increase it.

Non-Applicability Determinations

The following requirements have been determined not to be applicable to the subject facility due to the following:

a. **45CSR5 –** ***To Prevent and Control Air Pollution from the Operation of Coal Preparation Plants, Coal Handling Operations and Coal Refuse Disposal Areas***. Since the facility is subject to 45CSR2, according to 45CSR§5-~~2.4.b.~~2.5. the facility is not included in the definition of a "Coal Preparation Plant". Therefore, 45CSR5 does not apply to the facility, and particularly to its coal crushing operations and associated coal handling.

b. **45CSR7 –** ***To Prevent and Control Particulate Matter Air Pollution from Manufacturing Processes and Associated Operations.*** Since the facility is subject to 45CSR2, 45CSR§7-10.1. provides an exemption from 45CSR7.

c. **45CSR17 –** ***To Prevent and Control Particulate Matter Air Pollution from Material Handling, Preparation, Storage and Other Sources of Fugitive Particulate Matter.*** The facility is characterized by the handling and storage of materials that have the potential to produce fugitive particulate if not properly controlled. However, since the facility is subject to 45CSR2, it is not subject to this rule in accordance with the exemption granted in 45CSR§17-6.1.

d. **40 C.F.R. 60 Subpart D –** ***Standards of Performance for Fossil-fuel-fired Steam Generators for which Construction is Commenced after August 17, 1971.*** The fossil-fuel-fired steam generators potentially affected by this rule have not commenced construction or modification after August 17, 1971. Therefore, the units do not meet the applicability criteria under §60.40(c), and hence the NSPS does not apply.

e. **40 C.F.R. 60 Subpart Da –** ***Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978.*** The electric utility steam generating units (i.e., Unit 1 and Unit 2) potentially affected by this rule have not commenced construction or modification after September 18, 1978. Therefore, the units do not meet the applicability criteria under §60.40Da(a)(2), and hence the NSPS does not apply to Unit 1 and Unit 2. The auxiliary boiler (Aux 1) was not constructed or reconstructed "for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale." As such, Aux 1 does not meet the definition of an *Electric utility steam-generating unit* in §60.41Da, and therefore, does not meet the applicability criteria of §60.40Da(a). Consequently, NSPS Subpart Da does not apply to Aux 1.

f. **40 C.F.R. 60 Subpart K -** ***Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R.

§60.111(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after June 11, 1973 and prior to May 19, 1978. Therefore, the tanks do not meet the applicability criteria under §60.110, and hence the NSPS does not apply.

g. **40 C.F.R. 60 Subpart Ka - *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R. §60.111a(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after May 18, 1978 and prior to July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110a(a), and hence the NSPS does not apply.

h. **40 C.F.R. 60 Subpart Kb - *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 and On or Before October 4, 2023.*** Storage vessels potentially affected by this rule are exempted because they contain liquids with a maximum true vapor pressure of less than 3.5 kPa, have a storage capacity of less than 75 cubic meters, or have not commenced construction, reconstruction or modification after July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110b, and hence the NSPS does not apply.

i. **40 C.F.R. 60 Subpart Y – *Standards of Performance for Coal Preparation Plants.*** The coal handling equipment potentially affected by this rule has not been constructed or modified after October 24, 1974. Therefore, the equipment does not meet the applicability criteria set forth in 40 C.F.R. §60.250(b), and hence this NSPS does not apply.

j. **40 C.F.R. 63 Subpart Q – *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers.*** This facility does not include *industrial process cooling towers* that have operated with chromium-based water treatment chemicals. Therefore, the facility does not meet the applicability criteria set forth in §63.400(a), and hence this MACT does not apply to the facility.

Request for Variances or Alternatives
None.

Insignificant Activities
Insignificant emission unit(s) and activities are identified in the Title V application.

Comment Period
Beginning Date: (Date of Notice Publication)
Ending Date: (Publication Date PLUS 30 Days)

Point of Contact
All written comments should be addressed to the following individual and office:

Dan Roberts
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street SE
Charleston, WV 25304
304/926-0499 ext. 41902
Daniel.p.roberts@wv.gov

Procedure for Requesting Public Hearing
During the public comment period, any interested person may submit written comments on the draft permit and may request a public hearing, if no public hearing has already been scheduled. A request for public hearing shall be in writing and shall state the nature of the issues proposed to be raised in the hearing. The Secretary shall grant such a

request for a hearing if he/she concludes that a public hearing is appropriate. Any public hearing shall be held in the general area in which the facility is located.

Response to Comments (Statement of Basis)
Not applicable.

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Draft/Proposed Permit and Fact Sheet for Kentucky Power Company's Mitchell Plant - R30-05100005-2025

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Thu, Mar 20, 2025 at 2:16 PM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

Here is the draft/proposed fact sheet.

Dan

On Thu, Mar 20, 2025 at 12:36 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Carrie,
>
> Hey. Here is the draft proposed permit for your review. I am working on cleaning up and double checking the fact sheet and will send it shortly.
>
> Matt Palmer got back to me and confirmed that there was never an official acknowledged name change from Kentucky to Wheeling Power. I will forward the copy of an email which he sent me that ties this up. So, the documents will use Kentucky Power Company at this time, but he said they may submit the name change forms in the near future (probably before the comment period expires).
>
> Thanks,
> Dan

Draft FactSheet R30-05100005-2025 3-20-25.docx
96K

West Virginia Department of Environmental Protection
Division of Air Quality

Fact Sheet

For Draft/Proposed Renewal Permitting Action Under 45CSR30 and Title V of the Clean Air Act

Permit Number: **R30-05100005-2025**
Application Received: **May 19, 2024**
Plant Identification Number: **03-054-05100005**
Permittee: **Kentucky Power Company**
Facility Name: **Mitchell Plant**
Mailing Address: **1 Riverside Plaza, Columbus, Ohio 43215-2373**

Physical Location:	Cresap/Moundsville, Marshall County, West Virginia
UTM Coordinates:	516.00 km Easting • 4409.00 km Northing • Zone 17
Directions:	From Charleston take Interstate 77 North to Exit 179. Travel north on US Route 2 approximately 70 miles to Cresap. Facility is located on Route 2 approximately nine (9) miles south of Moundsville, WV.

Facility Description

The Mitchell Plant is a fossil fuel fired electric generation facility and operates under Standard Industrial Classification (SIC) code 4911. The facility consists of two (2) coal-fired steam generators with a rated design capacity of 7,020 mmBtu/hr each, one (1) oil-fired auxiliary boiler with a rated design capacity of 663 mmBtu/hr, one diesel emergency generator rated for 3,717 hp, one diesel emergency generator rated for 3,004 hp, one diesel emergency generator rated for 464 hp and various supporting operations such as coal and ash handling, limestone handling, and various tanks with insignificant emissions. The facility has the potential to operate seven (7) days per week, twenty-four (24) hours per day and fifty-two (52) weeks per year.

This renewal permit also incorporates minor modifications R30-05100005-2019 MM02, MM03 and MM04. The purpose of minor modification MM02 is to add a 2023 Cummins QSG12 513 hp diesel emergency generator LF DEG2 and a 600 gallon diesel fuel storage tank LF DEGT2. The purpose of minor modification MM03 is to replace the existing 1971 230 hp diesel emergency generator 17S with a 2023 Cummins CFP7E-F60 249 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #28 with a new 300 gallon diesel fuel tank. The purpose of MM04 is to replace the existing 1971 230 hp diesel emergency generator 18S with a 2024 Cummins CFP9E-F10 275 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #29 with a new 300 gallon diesel fuel tank.

Emissions Summary

Plantwide Emissions Summary [Tons per Year]		
Regulated Pollutants	**Potential Emissions [1]**	**2023 Actual Emissions [2]**
Carbon Monoxide (CO)	4,743.23	365.41
Nitrogen Oxides (NO_X)	36,332.05	1,587.76
Particulate Matter ($PM_{2.5}$)	1,096.2	21.94
Particulate Matter (PM_{10})	3,169.0	47.69
Total Particulate Matter (TSP)	5,423.79	134.40
Sulfur Dioxide (SO_2)	89,743.04	1193.52
Volatile Organic Compounds (VOC)	559.82	43.30

PM_{10} is a component of TSP.

Hazardous Air Pollutants [3]	Potential Emissions [1]	2023 Actual Emissions [2]
Hydrogen Chloride	12,337	6.54
Hydrogen Fluoride	1,071	5.98
Selenium	48.45	0.48
Manganese	3.77	0.04
Nickel	1.69	0.04
Arsenic	5.62	0.02
Mercury compounds	2.13	0.01
Beryllium	13.37	0.0013
Chromium	2.00	0.04
Cobalt	0.74	0.01
Lead	3.65	0.02

[1] The potential emissions are from the renewal application.
[2] Actual emissions are from the State and Local Emission Inventory System (SLEIS) Summary Report Total Emissions by Source.
[3] Some of the above HAPs may be counted as PM or VOCs.

Title V Program Applicability Basis

This facility has the potential to emit 4,743.23 tpy of CO; 36,332.05 tpy of NO_X; 3,169.0 tpy of PM_{10}; 89,743.04 tpy of SO_2; 559.82 tpy of VOC; 12,337 tpy of HCl; 1,071 tpy of HF; 48.45 tpy of Selenium; and 13.37 tpy of Beryllium. Due to this facility's potential to emit over 100 tons per year of criteria pollutant, over 10 tons per year of a single HAP, and over 25 tons per year of aggregate HAPs, Kentucky Power Company's Mitchell Plant is required to have an operating permit pursuant to Title V of the Federal Clean Air Act as amended and 45CSR30.

Legal and Factual Basis for Permit Conditions
The State and Federally-enforceable conditions of the Title V Operating Permits are based upon the requirements of the State of West Virginia Operating Permit Rule 45CSR30 for the purposes of Title V of the Federal Clean Air Act and the underlying applicable requirements in other state and federal rules.

This facility has been found to be subject to the following applicable rules:

Federal and State:	45CSR2	Control of particulate matter emissions from indirect heat exchangers
	45CSR2A	Testing and MRR requirements under 45CSR2
	45CSR6	Open burning prohibited.
	45CSR10	Control of sulfur dioxide emissions from indirect heat exchangers
	45CSR10A	Testing and MRR requirements under 45CSR10
	45CSR11	Standby plans for emergency episodes.
	45CSR13	Permits for construction/modification
	45CSR16	Standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60
	WV Code § 22-5-4 (a) (14)	The Secretary can request any pertinent information such as annual emission inventory reporting.
	45CSR30	Operating permit requirement
	45CSR33	Acid Rain Provisions and Permits
	45CSR34	Emission Standards for HAPs for Source Categories Pursuant to 40 C.F.R. Parts 61 and 63
	45CSR43	Cross-State Air Pollution Rule
	40 C.F.R. Part 60 Subpart Db	Standards of Performance for Industrial–Commercial-Institutional Steam Generating Units
	40 C.F.R. Part 60 Subpart OOO	NSPS for Non-metallic mineral processing plants
	40 C.F.R. Part 60 Subpart IIII	NSPS for Compression Ignition IC Engines
	40 C.F.R. Part 60 Subpart JJJJ	NSPS for Spark Ignition IC Engines
	40 C.F.R. Part 61	Asbestos inspection and removal
	40 C.F.R. Part 63 Subpart ZZZZ	RICE MACT
	40 C.F.R. Part 63 Subpart DDDDD	Boiler MACT for Major Sources of HAP
	40 C.F.R. Part 63 Subpart UUUUU	Utility Mercury and Air Toxics (MATS) MACT
	40 C.F.R. Part 64	Compliance Assurance Monitoring
	40 C.F.R. Part 72	Permits Regulation
	40 C.F.R. Part 73	Sulfur Dioxide Allowance System Permits Regulation
	40 C.F.R. Part 74	Sulfur Dioxide Opt-ins
	40 C.F.R. Part 75	Continuous Emissions Monitoring
	40 C.F.R. Part 76	Nitrogen Oxides Reduction Program
	40 C.F.R. Part 77	Excess Emissions
	40 C.F.R. Part 78	Appeals Procedure for Acid Rain Program
	40 C.F.R. Part 82, Subpart F	Ozone depleting substances
	40 CFR Part 97, Subpart AAAAA	CSAPR NO_x Annual Trading Program
	40 CFR Part 97, Subpart EEEEE	CSAPR NO_x Ozone Season Group 2 Trading Program
	40 CFR Part 97, Subpart CCCCC	CSAPR SO_2 Group 1 Trading Program
State Only:	45CSR4	No objectionable odors.

WVDAQ Letter dated September 3, 2002 addressed to Mr. Greg Wooten and signed by Jesse D. Adkins regarding the thermal decomposition of boiler cleaning solutions.

WVDAQ Letter dated January 21, 2004 addressed to Mr. Frank Blake and signed by Jesse D. Adkins regarding the combustion of demineralizer resins.

Each State and Federally-enforceable condition of the Title V Operating Permit references the specific relevant requirements of 45CSR30 or the applicable requirement upon which it is based. Any condition of the Title V permit that is enforceable by the State but is not Federally-enforceable is identified in the Title V permit as such.

The Secretary's authority to require standards under 40 C.F.R. Part 60 (NSPS), 40 C.F.R. Part 61 (NESHAPs), and 40 C.F.R. Part 63 (NESHAPs MACT) is provided in West Virginia Code §§ 22-5-1 *et seq.,* 45CSR16, 45CSR34 and 45CSR30.

Active Permits/Consent Orders

Permit or Consent Order Number	Date of Issuance	Permit Determinations or Amendments That Affect the Permit *(if any)*
R13-2608E	May 12, 2014	
G60-C057A	August 8, 2014	
Phase II Acid Rain Permit # R33-3948-2027-6	December 19, 2022	

Conditions from this facility's Rule 13 permit(s) governing construction-related specifications and timing requirements will not be included in the Title V Operating Permit but will remain independently enforceable under the applicable Rule 13 permit(s). All other conditions from this facility's Rule 13 permit(s) governing the source's operation and compliance have been incorporated into this Title V permit in accordance with the "General Requirement Comparison Table," which may be downloaded from DAQ's website.

Determinations and Justifications

This is the fourth renewal of the Title V Permit. This renewal permit also incorporates minor modifications R30-05100005-2019 MM02, MM03 and MM04. The purpose of minor modification MM02 is to add a 2023 Cummins QSG12 513 hp diesel emergency generator LF DEG2 and a 600 gallon diesel fuel storage tank LF DEGT2. The purpose of minor modification MM03 is to replace the existing 1971 230 hp diesel emergency generator 17S with a 2023 Cummins CFP7E-F60 249 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #28 with a new 300 gallon diesel fuel tank. The purpose of MM04 is to replace the existing 1971 230 hp diesel emergency generator 18S with a 2024 Cummins CFP9E-F10 275 hp Tier 3 diesel emergency generator and replace the existing 275 gallon diesel fuel tank #29 with a new 300 gallon diesel fuel tank.

The following changes have occurred since the most recent Title V permit was issued:

<u>Title V Permit Boilerplate changes:</u>

- **Condition 2.1.3.** – This condition was updated to delete the word "such" which was removed from 45CSR30 effective March 31, 2023. The citation was changed from "45CSR§30-2.12" to "45CSR§30-2.39" because the definition of "Secretary" was renumbered from a previous version of 45CSR30.

- **Condition 2.11.4** – The citation was changed from "45CSR§30-2.39" to "45CSR§30-2.40" because it was renumbered from a previous version of 45CSR30.

- **Conditions 2.17., 3.5.7. and 3.5.8.a.1.** – These conditions were deleted and replaced with "Reserved" because the emergency provisions under 45CSR§30-5.7 were removed from 45CSR30 effective March 31, 2023.

- **Condition 2.22.1** – "45CSR38" was removed from the citation because this rule has been repealed.

- **Conditions 3.1.6. and 3.3.1. –** The citation was revised to refer to the current version of the WV Code.

- **Condition 3.3.1.b. –** This condition was updated to include the following additional language: "If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit shall be revised in accordance with 45CSR§30-6.4. or 45CSR§30-6.5 as applicable."

- **Condition 3.5.3.** – This condition was updated to include the current EPA mailing address.

- **Condition 3.5.4.** – This condition was updated because the requirement to submit a certified emissions statement was removed from 45CSR30 effective March 31, 2023.

- **Condition 3.5.8.a.2.** – This condition was updated to replace the word "telefax" with "email" according to the change in 45CSR30 effective March 31, 2023.

<u>Updated Permit Language Due to Rule/Regulation Language Changes:</u>

- **Conditions 7.1.6., 7.1.7.** – This condition was amended to match the revised 40 CFR 60 Subpart ZZZZ.

- **Conditions 8.1.5., 8.1.7. through 8.1.9. and 8.5.7.** – These conditions were amended to match the revised 40 CFR 60 Subpart IIII.

- **Conditions 8.1.13., 8.4.6.(3) and 8.5.1.** – These conditions were amended to match the revised 40 CFR 60 Subpart JJJJ.

- **Conditions 8.5.2. through 8.5.6.** – These new conditions were added to match the revised 40 CFR 60 Subpart JJJJ.

- **Conditions 8.5.8. through 8.5.12.** – These new conditions were amended to match the revised 40 CFR 60 Subpart IIII.

<u>Changes requested in minor modification application R30-051000051-2019 MM02:</u>

- **Condition 1.1** – The Emission Units table was amended to add an entry for LF DEG2 and LF DEGT2.

- **Condition 8.0** – Diesel Driven Emergency Fire Pump Engine LF DEG2 was added to the list of emission units and emission point IDs in the title section.

- **Conditions 8.1.5. through 8.1.9., 8.2.1., 8.4.4., 8.5.7.** – LF DEG2 was added to the citation section of these existing conditions.

- **Condition 8.1.15.** – This requirement from 45 CSR 63 Subpart ZZZZ was added for LF DEG2.

- **Conditions 8.5.8. through 8.5.12.** – New requirements from the revised Subpart IIII were added for LF DEG2.

<u>Changes requested in minor modification application R30-051000051-2019 MM03:</u>

- **Condition 1.1** – The Emission Units table was amended to modify the entry for 17S to include the information for the new diesel emergency engine.
- **Condition 7.0**. – The references to Emergency Diesel Driven Fire Pumps 17S and 18S were removed because the new replacement engines were moved to Section 8.0.
- **Condition 8.0** – Diesel Driven Emergency Fire Pump Engines 17E and 18E were added to the list of emission units and emission point IDs in the title section.
- **Condition 8.1.5.** – This requirement from 40 CFR 60 Subpart IIII was added for 17E.
- **Conditions 8.1.6. through 8.1.9., 8.2.1., 8.4.4., 8.5.7.** – 17E was added to the citation section of these existing conditions.
- **Conditions 8.5.8. through 8.5.12.** – New requirements from the revised 40 CFR 60 Subpart IIII were added for 17E.

Changes requested in minor modification application R30-051000051-2019 MM04:

- **Condition 1.1** – The Emission Units table was amended to modify the entry for 18S to include the information for the new diesel emergency engine.
- **Condition 7.0**. – The references to Emergency Diesel Driven Fire Pumps 17S and 18S were removed because the new replacement engines were moved to Section 8.0.
- **Condition 8.0** – Diesel Driven Emergency Fire Pump Engines 17E and 18E were added to the list of emission units and emission point IDs in the title section.
- **Condition 8.1.5.** – This requirement from Subpart IIII was added for 18E.
- **Conditions 8.1.6. through 8.1.9., 8.2.1., 8.4.4., 8.5.7.** – 18E was added to the citation section of these existing conditions.
- **Conditions 8.5.8. through 8.5.12.** – New requirements from the revised Subpart IIII were added for 18E.

Changes requested in renewal application R30-051000051-2025:

- **Condition 1.1** – The Emission Units table was amended to delete Tank #44 and add Tanks #64 through #69.

Notes: In the renewal application, the company requested to remove the 2013 126 hp Generac SG080 LB4S liquid propane gas fired emergency generator LPG and the associated 500 gallon tank LPT from the Title V permit. However, these emission units are both permitted within NSR General Permit G60-C057A. Therefore, these sources cannot be removed until G60-C057A is modified to remove them.

Also, the company requested to increase the maximum annual amount of polymer and organsulfide to be delivered to the facility from 13,500 gal/yr to 25,000 gal/yr in the Title V permit. However, this annual throughput limit is permitted within NSR Permit R13-2608E. Therefore, this annual throughput limit cannot be changed until R13-2608E has been modified to increase it.

Non-Applicability Determinations

The following requirements have been determined not to be applicable to the subject facility due to the following:

a. **45CSR5 –** ***To Prevent and Control Air Pollution from the Operation of Coal Preparation Plants, Coal Handling Operations and Coal Refuse Disposal Areas***. Since the facility is subject to 45CSR2, according to

45CSR§5-2.4.b. the facility is not included in the definition of a "Coal Preparation Plant". Therefore, 45CSR5 does not apply to the facility, and particularly to its coal crushing operations and associated coal handling.

b. **45CSR7 – *To Prevent and Control Particulate Matter Air Pollution from Manufacturing Processes and Associated Operations.*** Since the facility is subject to 45CSR2, 45CSR§7-10.1. provides an exemption from 45CSR7.

c. **45CSR17 – *To Prevent and Control Particulate Matter Air Pollution from Material Handling, Preparation, Storage and Other Sources of Fugitive Particulate Matter.*** The facility is characterized by the handling and storage of materials that have the potential to produce fugitive particulate if not properly controlled. However, since the facility is subject to 45CSR2, it is not subject to this rule in accordance with the exemption granted in 45CSR§17-6.1.

d. **40 C.F.R. 60 Subpart D – *Standards of Performance for Fossil-fuel-fired Steam Generators for which Construction is Commenced after August 17, 1971.*** The fossil-fuel-fired steam generators potentially affected by this rule have not commenced construction or modification after August 17, 1971. Therefore, the units do not meet the applicability criteria under §60.40(c), and hence the NSPS does not apply.

e. **40 C.F.R. 60 Subpart Da – *Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978.*** The electric utility steam generating units (i.e., Unit 1 and Unit 2) potentially affected by this rule have not commenced construction or modification after September 18, 1978. Therefore, the units do not meet the applicability criteria under §60.40Da(a)(2), and hence the NSPS does not apply to Unit 1 and Unit 2. The auxiliary boiler (Aux 1) was not constructed or reconstructed "for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale." As such, Aux 1 does not meet the definition of an *Electric utility steam-generating unit* in §60.41Da, and therefore, does not meet the applicability criteria of §60.40Da(a). Consequently, NSPS Subpart Da does not apply to Aux 1.

f. **40 C.F.R. 60 Subpart K - *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R. §60.111(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after June 11, 1973 and prior to May 19, 1978. Therefore, the tanks do not meet the applicability criteria under §60.110, and hence the NSPS does not apply.

g. **40 C.F.R. 60 Subpart Ka - *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R. §60.111a(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after May 18, 1978 and prior to July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110a(a), and hence the NSPS does not apply.

h. **40 C.F.R. 60 Subpart Kb - *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.*** Storage vessels potentially affected by this rule are exempted because they contain liquids with a maximum true vapor pressure of less than 3.5 kPa, have a storage capacity of less than 75 cubic meters, or have not commenced construction, reconstruction or modification after July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110b, and hence the NSPS does not apply.

i. **40 C.F.R. 60 Subpart Y – *Standards of Performance for Coal Preparation Plants.*** The coal handling equipment potentially affected by this rule has not been constructed or modified after October 24, 1974. Therefore, the equipment does not meet the applicability criteria set forth in 40 C.F.R. §60.250(b), and hence this NSPS does not apply.

j. **40 C.F.R. 63 Subpart Q – *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers.*** This facility does not include *industrial process cooling towers* that have operated with chromium-based water treatment chemicals. Therefore, the facility does not meet the applicability criteria set forth in §63.400(a), and hence this MACT does not apply to the facility.

Request for Variances or Alternatives

None.

Insignificant Activities

Insignificant emission unit(s) and activities are identified in the Title V application.

Comment Period

Beginning Date: (Date of Notice Publication)
Ending Date: (Publication Date PLUS 30 Days)

Point of Contact

All written comments should be addressed to the following individual and office:

Dan Roberts
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street SE
Charleston, WV 25304
304/926-0499 ext. 41902
Daniel.p.roberts@wv.gov

Procedure for Requesting Public Hearing

During the public comment period, any interested person may submit written comments on the draft permit and may request a public hearing, if no public hearing has already been scheduled. A request for public hearing shall be in writing and shall state the nature of the issues proposed to be raised in the hearing. The Secretary shall grant such a request for a hearing if he/she concludes that a public hearing is appropriate. Any public hearing shall be held in the general area in which the facility is located.

Response to Comments (Statement of Basis)

Not applicable.

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Wheeling Power transfer

1 message

Scott, Kimberly A <kimberly.a.scott@wv.gov> Thu, Mar 20, 2025 at 2:16 PM
To: "Roberts, Daniel P" <daniel.p.roberts@wv.gov>

Dan,

Thanks for the update, I will put a copy of this email in their electronic file in our Permit Transfer folder.

Kim

On Thu, Mar 20, 2025 at 1:07 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Hey. I called Matt Palmer who is the Plant Environmental Coordinator at the Mitchell Power Plant this morning to see if he had any information regarding the proposed name change from Kentucky Power Company to Wheeling Power Company that originated in 2022. Mr. Palmer consulted with Brandon Belcher who is the Environmental Specialist Sr. at AEP Service Corporation in Columbus, OH. Mr. Palmer found an email and sent it to me and I forwarded it to you all. It confirms that there was a name change request and fee submitted, but it was later determined that there was no need to transfer the air permits from Kentucky Power Company at that time. FYI... the transfer of the Kentucky Power portion to Liberty fell through and never happened.
>
> Mr. Palmer also stated that they would probably go ahead and submit new paperwork to transfer the name to Wheeling Power Company in the near future.
>
> I hope this clears things up with all parties involved. Feel free to respond if anyone has any further questions.
>
> Thanks for everyone's time and effort on this!
>
> Thanks again,
> Dan
>
> ---------- Forwarded message ---------
> From: **G M Palmer** <gmpalmer@aep.com>
> Date: Thu, Mar 20, 2025 at 11:54 AM
> Subject: Wheeling Power transfer
> To: Daniel.P.Roberts@wv.gov <Daniel.P.Roberts@wv.gov>
> Cc: Brandon T Belcher <btbelcher@aep.com>
>
> Email info below.

G M Palmer

From: Gregory J Wooten
Sent: Tuesday, September 6, 2022 8:33 PM
To: Douglas J Rosenberger
Cc: Todd A March; Jeffrey D Clark; G M Palmer
Subject: FW: Mitchell Transfer from Kentucky to Wheeling Power Company

Doug,
After a recent discussion with WVDEP, it became unnecessary to transfer the Title V Permit and the Class II General Air Permit.

Last week, I spoke with the WVDEP Air Director (Laura Crowder) about the Mitchell Permit transfers from Kentucky Power to Wheeling Power. Laura had also spoken with the WVDEP legal department just to confirm that her position was correct.

She indicated that in this situation, there is no need to transfer the air permits. She explained that under the air regulations, WVDEP has the option to issue the permits either in the name of the owner or the operator. Because Kentucky Power will still be one of the owners (until the liberty transfer), there is no need to transfer the permits out of Kentucky Power. She mentioned that if the Designated Representative (Scott Weaver) or the plant responsible official (plant manager) was changing, then those changes would need to be made. Since neither are changing, there is nothing to change.

She did indicate that we will need to submit a request for ownership transfer when the Kentucky power portion is transferred to Liberty. Laura said they have records of the fee we paid for the original transfer request, so there will be no need to pay an additional fee when the ownership transfer occurs.

Greg

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY
GREGORY J WOOTEN | ENVIRONMENTAL ENGINEER STAFF
GJWOOTEN@AEP.COM | A:8.200.1262
1 RIVERSIDE PLAZA, COLUMBUS, OH 43215

Thanks,

AMERICAN ELECTRIC POWER
G M PALMER | ENVIRONMENTAL COORD PRIN
GMPALMER@AEP.COM | D:304.843.6048 | C:304.559.4538
8999 ENERGY ROAD, MOUNDSVILLE, WV 26041

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Title V Info Sheet and Permits for Kentucky Power Company - Mitchell Plant - R30-05100005-2025 renewal

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Thu, Mar 20, 2025 at 1:21 PM
To: Stephanie R Mink <stephanie.r.mink@wv.gov>

Stephanie,

Hey. Here is the Title V Info Sheet and the facility's R13-2806E permit and G60-C057A General Permit Registration.

Dan

3 attachments

T5_Info_Table R30-05100005-2025.doc
40K

051-00005_PERM_G60-C057A.doc
312K

051-00005_PERM_13-2608E.doc
519K

Facility Information for Draft/Proposed/Final Permits

Engineer and E-Mail Address	Dan Roberts – daniel.p.roberts@wv.gov
Company Name	Kentucky Power Company
Facility Name	Mitchell Plant
County	Marshall
Permit No.	R30-05100005-2025
Permit Type	Renewal
Newspaper	*The Intelligencer*
Responsible Official Title Street or P. O. Address City, State, Zip E-Mail Address	Joshua D. Snodgrass Plant Manager P.O. Box K Moundsville, WV 26041 jdsnodgrass@aep.com
Environmental Contact Title Street or P. O. Address City, State, Zip E-Mail Address	G.M. (Matt) Palmer Plant Environmental Coordinator P.O. Box K Moundsville, WV 26041 gmpalmer@aep.com
Consultant's Name and E-mail Address	Brandon T. Belcher, Environmental Specialist Sr. btbelcher@aep.com
Affected States and/or Class I Area	Ohio, Pennsylvania
Regional Office	Wheeling
Reg 13 Permit Nos. (if applicable)	R13-2608E, G60-C057A

E-mail to Stephanie and **create a folder** under *G:\Shared drives\DEP AQ Permitting\AQ Permitting\TITLEV\Permits* for your permit and save the following files:

Draft/Proposed	Final
Facility Information Table	Facility Information Table
Notice	
Draft Permit	Final Permit
Fact Sheet	Final Fact Sheet
Reg 13 Permits (if applicable)	

West Virginia Department of Environmental Protection

Earl Ray Tomblin
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Class I Administrative Update Permit

R13-2608E

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:

AEP Generation Resources, Inc.
Mitchell Plant
051-00005

William F. Dunham
Deputy Director

Issued: May 12, 2014

This permit will supercede and replace Permit R13-2608D.

Facility Location:	State Route 2 Cresap/Moundsville, Marshall County, West Virginia
Mailing Address:	Mitchell Plant P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generating Plant
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Permit Type:	Administrative Update
Description of Change:	This update is to correctly codify the term of the limited use for Boiler Aux-1 in the terms as defined in the Subpart DDDDD of Part 63 of Chapter 40 and correctly define the compliance path for Aux-1 under Subpart Db of Part 60 in Chapter 40.

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	Design Capacity	Control Device
1S - Limestone Material Handling				
BUN-1		Limestone Unloading Crane	1,000 TPH	None
RH-1		Limestone Unloading Hopper	60 Tons	WS/PE
VF-1		Limestone Unloading Feeder	750 TPH	FE
BC-1		Limestone Dock/Connecting Conveyor	750 TPH	PE
TH-1		Limestone Transfer House #1	750 TPH	FE
BC-2		Limestone Storage Pile Stacking Conveyor	750 TPH	PE
LSSP		Limestone Active/Long-Term Stockpile	41,300 Tons	None
2S - Gypsum Material Handling				
BC-8		Vacuum Collecting Conveyor	200 TPH	PE
TH-3		Gypsum Transfer House #3	200 TPH	FE
BC-9		Connecting Conveyor	200 TPH	PE
TH-4		Gypsum Transfer House #4	200 TPH	FE
BC-10		Connecting Conveyor	200 TPH	PE
TH-5		Gypsum Transfer House #5	200 TPH	FE
BC-11		Connecting Conveyor	200 TPH	PE
TH-6		Gypsum Transfer House #6	200 TPH	FE
BC-12		Stacking Tripper Conveyor	200 TPH	PE
GSP		Gypsum Stockpile	15,600 Tons	FE
PSR-1		Traveling Portal Scraper Reclaimer	1,000 TPH	FE
BC-14		Reclaim Conveyor	1,000 TPH	PE
TH-7		Transfer House #7	1,000 TPH	FE
BC-13		Bypass Conveyor	200 TPH	PE
BC-15		Connecting Conveyor	1,000 TPH	PE
TH-1		Transfer House #1	1,000 TPH	FE
BC-16		Transfer Conveyor	1,000 TPH	PE
BL-1		Barge Loader	1,000 TPH	PE
BC-14		Reclaim Conveyor Extension	1,000 TPH	PE
TH-8		Transfer House #8	1,000 TPH	FE
BC-19		Transfer Conveyor	1,000 TPH	PE
TH-9		Transfer House #9	1,000 TPH	FE
BC-20		Transfer Conveyor	1,000 TPH	FE
TH-10		Transfer House #10	1,000 TPH	PE

BC-21		Transfer Conveyor to 21	1,000 TPH	FE
BUN-1		Clamshell Unloading Crane	1,000 TPH	
RH-4		Gypsum Unloading Hopper	30 tons	WSPE
RP-1		Gypsum Rotary Plow	750 TPH	FE
BC-17		Dock Connecting Conveyor	750 TPH	PE
TH-7		Transfer House #7	750 TPH	FE
BC-18		Bypass Conveyor	750 TPH	PE
TH-6		Transfer House #6	750 TPH	FE
3S		**Limestone Mineral Processing**		
VF-2		Limestone Reclaim Feeder 2	750 TPH	FE
VF-3		Limestone Reclaim Feeder 3	750 TPH	FE
BC-3		Limestone Tunnel Reclaim Conveyor	750 TPH	PE
FB-1		Emergency Limestone Reclaim Feeder/Breaker	750 TPH	None
TH-2		Limestone Transfer House 2	750 TPH	FE
BC-4		Limestone Silo A Feed Conveyor	750 TPH	PE
BC-5		Limestone Silo B Feed Conveyor	750 TPH	PE
BC-6		Limestone Silo C Feed Conveyor (future)	750 TPH	PE
LSB-1	6E	Limestone Silo A	900 tons	FF
LSB-2	7E	Limestone Silo B	900 tons	FF
LSB-3	8E	Limestone Silo C (future)	900 tons	FF
		Vibrating Bin Discharger (one per silo)	68.4 TPH	FE
LSWF-1 LSWF-2 LSWF-3		Limestone Weigh Feeder	68.4 TPH	FE
		Wet Ball Mill (one per silo)	68.4 TPH	FE
4S		**Dry Sorbent Material Handling**		
		Truck Unloading Connection (2)	25 TPH	FE
DSSB-1	10E	Dry Sorbent Storage Silo #1	500 Tons	FE/FF
DSSB-1	11E	Dry Sorbent Storage Silo #2	500 Tons	FE/FF
		Aeration Distribution Bins	4.6 TPH	FE
		De-aeration Bins	4.6 TPH	FE
		Rotary Feeder	4.6 TPH	FE
5S		**Coal Blending System**		
HTS-1		Transfer House #1	3,000 TPH	FE
HSC-1		Stacking Conveyor #1	3,000 TPH	PE
HTS-2A		Transfer House #2A	3,000 TPH	FE
HSC-2		Stacking Conveyor #2	3,000 TPH	PE

HTS-3		Transfer House #3	3,000 TPH	FE
HSC-3		Stacking Conveyor #3	3,000 TPH	PE
SH-1		Stacking Hopper SH-1 Transfer to SC-3 (receives coal from existing plant radial stacker R9)	3,000 TPH	FE
HSC-3 to High Sulfur Pile (CSA-2, existing)		Transfer from Stacking Conveyor HSC-3 to the High Sulfur Coal Pile located at existing North Yard Storage Area (CSA-2)	3,000 TPH	ST
HVF-1		Coal Reclaim Feeder 1	800 TPH	FE
HVF-2		Coal Reclaim Feeder 1	800 TPH	FE
HVF-3		Coal Reclaim Feeder 1	800 TPH	FE
HVF-4		Coal Reclaim Feeder 1	800 TPH	FE
HVF-1 through HVF-4 to HRC-1 (Transfer)_		Transfer from Vibrating Feeders HVF-1 through HVF-4 to Reclaim Conveyor HRC-1	1,600 TPH	FE
HRC-1		Coal Tunnel Reclaim Conveyor	1,600 TPH	PE
HTS-2B		Coal Transfer House #2B	1,600 TPH	FE
HRC-2		Reclaim Conveyor #2	1,600 TPH	PE
HTS-4		Coal Transfer House #4	1,600 TPH	FE
HRC-3		Reclaim Conveyor #3	1,600 TPH	PE
HTS-5		Coal Transfer House #5	1,600 TPH	FE
SB-1		Surge Bin #1	80 Tons	FE
HBF-1A		Belt Feeder 1A	800 TPH	PE
HBF-1B		Belt Feeder 1B	800 TPH	PE
HBF-1A/1B to BF-4E/4W (Transfer)		Transfer from Belt Feeders HBF-1A and HBF-1B to Existing Coal Conveyors 4E and 4W	1,600 TPH	FE
6S. 7S		**Emergency Quench Water System**		
6S	15E	Diesel Fired Engine for Quench Pump #1	60 Bhp	None
7S	16E	Diesel Fired Engine for Quench Pump #2	60 Bhp	None
9S		**Magnesium Hydroxide Material Handling System**		
MHM-1		Magnesium Hydroxide Mix Tank	1,000 Gallons	
MHM-2		Magnesium Hydroxide Mix Tank	1,000 Gallons	
11S		**Wastewater Treatment System Material Handling**		
		Truck Unloading Connection (2)	25 TPH	FE
		Lime Storage Silo #1	100 TPH	FE//FF
		Lime Storage Silo #2	100 TPH	FE//FF
		Wastewater Treatment Cake Stockpile	3,600 Tons	BE

FB-2		Filter Cake Feeder/Breaker	600 TPH	PE
BC-22		Transfer Conveyor 22	600 TPH	PE
TH-12		Transfer House #12	600 TPH	PE
Fly Ash Handling System				
ME-1A	EP-1	Unit 1 Mechanical Exhauster		FF/Separator
ME-1B	EP-2	Unit 1 Mechanical Exhauster		FF/Separator
ME-1C	EP-3	Unit 1 Mechanical Exhauster		FF/Separator
ME-2A	EP-4	Unit 2 Mechanical Exhauster		FF/Separator
ME-2B	EP-5	Unit 2 Mechanical Exhauster		FF/Separator
ME-2C	EP-6	Unit 2 Mechanical Exhauster		FF/Separator
FAS-A	EP-7	Fly Ash Silo A	2,160 tons	FF Bin Vent
FAS-B	EP-8	Fly Ash Silo B	2,160 tons	FF Bin Vent
FAS-B	EP-8	Fly Ash Silo B	2,160 tons	FF Bin Vent
WFA-AA	F-1	Conditioned fly ash transfer from Silo A to Truck	360 TPH	MC
WFA-BA	F-2	Conditioned fly ash transfer from Silo B to Truck	360 TPH	MC
WFA-CA	F-3	Conditioned fly ash transfer from Silo C to Truck	360 TPH	MC
WFA-BA	F-4	Conditioned fly ash transfer from Silo A to Truck	360 TPH	MC
WFA-BB	F-5	Conditioned fly ash transfer from Silo B to Truck	360 TPH	MC
WFA-CB	F-6	Conditioned fly ash transfer from Silo C to Truck	360 TPH	MC
TC-A	EP-10	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
TC-B	EP-11	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
TC-C	EP-12	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
Auxiliary Boiler				
Aux-1	Aux-ML-1	Auxiliary Boiler using Flue Gas Recirculation with Low NO_x Burners	663 MMBtu/hr	None
You can type whatever you want here :o)				

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	**Ppm_V 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	**SO_2**	Sulfur Dioxide
lbs/hr	Pounds per Hour	**TAP**	Toxic Air Pollutant
LDAR	Leak Detection and Repair	**TPY**	Tons per Year
M	Thousand	**TRS**	Total Reduced Sulfur
MACT	Maximum Achievable Control Technology	**TSP**	Total Suspended Particulate
MDHI	Maximum Design Heat Input	**USEPA**	United States Environmental Protection Agency
MM	Million	**UTM**	Universal Transverse Mercator
MMBtu/hr *or* **mmbtu/hr**	Million British Thermal Units per Hour	**VEE**	Visual Emissions Evaluation
MMCF/hr *or* **mmcf/hr**	Million Cubic Feet per Hour	**VOC**	Volatile Organic Compounds
NA		**VOL**	Volatile Organic Liquids
NAAQS			
NESHAPS			

Not Applicable
National Ambient Air
Quality Standards
National Emissions
Standards for Hazardous
Air Pollutants

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;*

2.3.3. 45CSR19 – *Requirements for Pre-Construction Review, Determination of Emission Offsets for Proposed New or Modified Stationary Sources of Air Pollution and Emission Trading for Intrasource Pollutants.*

2.4. Term and Renewal

2.4.1. This permit supersedes and replaces previously issued Permit R13-2608D. 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 R13-2608, R13-2608A, R13-2608B, R13-2608C, R13-2608D, R13-2608E, 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.]

3.2. 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 sourcespecific 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 sourcespecific 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

4.1. Limitations and Standards

4.1.1. Limestone transferred across belt conveyor BC-1 to Transfer House #1 [TH-1] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.

4.1.2 Limestone transferred across belt conveyor BC-3 to Transfer House #2 [TH-2] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.

4.1.3. Gypsum transferred across belt conveyor BC-9 to Transfer House #4 [TH-4] shall be limited to a maximum transfer rate of 200 tons per hour and 1,700,000 tons per year.

4.1.4. Gypsum and wastewater treatment system cake transferred across belt conveyor BC-14 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,912,000 tons per year.

4.1.5. Gypsum transferred across belt conveyor BC-17 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 750 tons per hour and 1,200,000 tons per year.

4.1.6. Gypsum transferred across belt conveyor BC-19 to Transfer House #9 [TH-9] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,700,000 tons per year.

4.1.7. Coal transferred across belt conveyor HSC-1 shall be limited to a maximum transfer rate of 3,000 tons per hour and 5,732,544 tons per year.

4.1.8. Dry Sorbent (Trona or Hydrated Lime) for SO_3 mitigation shall be delivered to the facility at a maximum annual rate of 81,000 tons per year.

4.1.9. Liquid magnesium hydroxide shall be delivered to the facility at a maximum annual rate of 6,600,000 gallons per year.

4.1.10. Hydrated lime for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 3,200 tons per year.

4.1.11. Ferric Chloride for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 110,000 gallons per year.

4.1.12. Acid (hydrochloric or sulfuric) for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 170,000 gallons per year.

4.1.13. Polymer and organosulfide for the FGD wastewater treatment facility shall be delivered to the facility at a maximum annual rate of 13,500 gallons per year.

4.1.14. The diesel-fired engines [6S and 7S] used to power the emergency quench water system shall be limited to a total maximum combined annual operating schedule of 200 hours per year.

4.1.15. Compliance with all annual operating limits shall be determined using a twelve month rolling total. A twelve month rolling total shall mean the sum of the quantified operating data at any given time during the previous twelve (12) consecutive calendar months.

4.1.16. The permittee shall maintain a water truck on site and in good operating condition, and shall utilize same to apply water as often as is necessary in order to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads and other work areas where mobile equipment is used. The spraybar shall be equipped with spray nozzles, of sufficient size and number, so as to provide adequate coverage to the area being treated.

The pump delivering the water shall be of sufficient size and capacity so as to be capable of delivering to the spray nozzle(s) an adequate quantity of water and at a sufficient pressure, so as to assure that the treatment process will minimize the atmospheric entrainment of fugitive particulate emissions generated from the haulroads and work areas where mobile equipment is used.

4.1.17. Additionally, at least three times per year the permittee shall apply a mixture of water and an environmentally acceptable dust control additive hereafter referred to as solution to all unpaved haul roads. The solution shall have a concentration of dust control additive sufficient to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads.

4.1.18. The permittee shall not cause, suffer, allow or permit any source of fugitive particulate matter to operate that is not equipped with a fugitive particulate matter control system. This system shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter.

4.1.19. The installation and operation of the proposed Limestone Processing equipment [3S] shall be applicable to the limits and requirements set forth by 40CFR60 - Subpart OOO, "Standards of performance for non-metallic mineral processing plants."

a. The material transfers across the conveyors within the enclosed transfer stations and ball mill within the processing building will be limited to the opacity emissions from the building or building vents. The buildings will be limited to emissions of no visible opacity per 40CFR60.672(e)(1), and the vents from the buildings will be limited to an opacity of 7% and particulate emissions of 0.022 grains per dry standard cubic foot, per 40CFR60.672(e)(2).

b. The emissions from the baghouse on each of the limestone day bins will be limited to 7% opacity per 40CFR60.672(f).

c. All material transfer points outside of the buildings will be limited to a maximum 10% opacity per 40CFR60.672(b).

d. In order to comply with the emission and opacity limitations of this Subpart, the permittee shall employ dust suppression methods to minimize particulate emissions from the limestone processing equipment. In order to demonstrate compliance, in accordance to the requirements of the regulation, the applicant shall conduct performance testing and monitoring activities as set forth by this Subpart.

4.1.20. The maximum amount of fly ash handled by the fly ash handling system shall not exceed 800,000 tons per year on a dry (1% moisture) basis (i.e 980,000 tons per year at 20% moisture). Compliance with the throughput limit shall be determined using a rolling yearly total. A rolling yearly total shall mean the sum of the fly ash transferred for the previous twelve (12) consecutive calendar months.

4.1.21. PM emissions from Mechanical Exhausters ME-1A, ME-1B and ME-1C shall not exceed 0.16 lb/hr and 0.69 tpy individually nor 0.32 lb/hr and 1.38 tons per year combined.

4.1.22. PM emissions from Mechanical Exhausters ME-2A, ME-2B and ME-2C shall not exceed 0.15 lb/hr and 0.65 tpy individually nor 0.30 lb/hr and 1.30 tons per year combined.

4.1.23. PM emissions from Bin Vent Filters BVF-A, BVF-B and BVF-C shall not exceed 0.75 lb/hr nor 3.25 tpy combined.

4.1.24. PM emissions from the transfer of conditioned fly ash from the silos to trucks (WFA-AA, WFA-AB, WFA-BA, WFA-BB, WFA-CA, and WFA-CB) shall not exceed 0.07 pounds per hour nor 0.09 tons per year combined.

4.1.25. **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. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.1. and 4.1.2. of this permit, the permittee shall monitor the hourly and annual limestone transfer rates across belt conveyor BC-1 to Transfer House #1 [TH-1] and across belt conveyor BC-3 to Transfer House #2 [TH-2].

4.2.2. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.3., 4.1.4., 4.1.5. and 4.1.6. of this permit, the permittee shall monitor the hourly and annual gypsum and wastewater treatment cake transfer rates across belt conveyors BC-9 to Transfer House #4 [TH-4], BC-14 to Transfer House #7 [TH-7], BC-17 to the Transfer House #7 Extension, and BC-19 to Transfer House #9 [TH-9].

4.2.3. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.7. of this permit, the permittee shall monitor the hourly and annual coal transfer rates across belt conveyor HSC-1 to Transfer Station #2A.

4.2.4. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the SO_3 mitigation system, as set forth by Section 4.1.8. and 4.1.9. of this permit, the permittee shall monitor the on-site delivery of dry sorbent (including trona and hydrated lime) and liquid magnesium hydroxide.

4.2.5. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the FGD wastewater treatment system, as set forth by Sections 4.1.10. through 4.1.13. of this permit, the permittee shall monitor the on-site delivery of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide.

4.2.6. For the purpose of determining compliance with the operating limits set forth by Section 4.1.14. of this permit, the permittee shall monitor the operating schedule of the diesel-fired engine [6S and 7S] used to power the emergency quench water system.

4.2.7. For the purpose of determining compliance with the limits associated with disposal of dry fly ash, as set forth by Section 4.1.20 of this permit, the permittee shall monitor and record the amount of dry fly ash disposed of.

4.2.8. For the purpose of determining compliance with the operating limits set forth by Section 4.1.17. of this permit, the permittee shall monitor and record the date that chemical solution is applied to the haulroads along with the amount and concentration of the solution applied.

4.3. Testing Requirements

4.3.1. For the purpose of determining compliance with the performance testing requirements of 40 C.F.R. Part 60, Subpart OOO, as set forth by Section 4.1.19. of this permit, the permittee shall conduct compliance testing of the permitted facility within 180 days of the equipment start-up. These tests will be used to determine the particulate matter emissions generated from the open transfer points and processing operations. The testing methods to be employed are as follows:

Pollutant	USEPA Test Method*
Determination of the Opacity of Emissions	9

* Per 40CFR60, Appendix A

The permittee shall submit to the Director of the DAQ a test protocol detailing the proposed test methods, date, and time testing is to take place, testing locations, and any other relevant information. The test protocol must be received by the Director no less than thirty (30) days prior to the date the testing is to take place. The Director shall be notified at least fifteen (15) days in advance of the actual dates and times during which the tests will be conducted. The results of emissions testing shall be submitted to the DAQ within thirty (30) days of completion of testing.

4.3.2. Within 120 days of startup of the dry ash handling system, the permittee shall perform or have performed EPA approved tests (or other methods as approved by WVDAQ) to determine maximum PM emissions from any one of the Silo Bin Vent Filters (BVF-A, BVF-B or BVF-C).

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 the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.1. of this permit, the permittee shall maintain monthly records of the amount of limestone transferred across the monitored belt conveyors.

4.4.5. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.2. of this permit, the permittee shall maintain monthly records of the amount of gypsum and wastewater treatment cake transferred across the monitored belt conveyors.

4.4.6. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.3. of this permit, the permittee shall maintain monthly records of the amount of coal transferred across the monitored belt conveyor.

4.4.7. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.4. of this permit, the permittee shall maintain monthly records of the amount of dry sorbent (trona and hydrated lime) and liquid magnesium hydroxide delivered to the facility via truck.

4.4.8. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.5. of this permit, the permittee shall maintain monthly records of the amount of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide delivered to the facility via truck.

4.4.9. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.6. of this permit, the permittee shall maintain monthly records of the hours of operation of the diesel-fired engines [6S and 7S].

4.4.10. For the purposes of determining compliance with Section 4.1.16., 4.1.17., and 4.1.18. of this permit, the permittee shall maintain records of the amount of dust control additive used at the facility and the dates the solution was applied.

4.4.11. All records produced in accordance to the requirements set forth by Section 4.4. of this permit shall be maintained on-site for a period of no less than five (5) years and made available to the Director or his duly authorized representative upon request. At a time prior to being submitted to the Director, all records shall be certified and signed by a "Responsible Official" or a duly authorized representative, utilizing the attached Certification of Data Accuracy statement.

4.4.12. For the purposes of determining compliance with the maximum throughput limit set forth in Condition 4.1.20 above, the facility shall maintain monthly (and calculated rolling yearly total) records of the amount of fly ash handled by the Units 1 and 2 fly ash system.

5.0. Source-Specific Requirements for the Auxiliary Boiler (Aux-1)

5.1. Limitations and Standards

5.1.1. The following conditions and requirements are specific to the Boiler Aux-1:

a. Emissions from the boiler shall not exceed the following limits:

Pollutant	lb/hr	tpy
SO_2	39.78*	17.42
NO_x	99.45	43.56
CO	206.86	90.60
VOC	0.95	0.41
PM (filterable +condensable.)	15.63	6.85
PM_{10} (filterable +condensable)	10.90	4.77
$PM_{2.5}$ (filterable +condensable)	7.34	3.22
CO_2	105,606.4	46,255.6
N_2O	0.88	0.38
CH_4	4.38	1.92
CO_{2e} (Total)	105,971.18	46,413.72
Formaldehyde	0.29	0.13
Benzene	0.01	0.01
Ethylbenzene	0.01	0.01
Toluene	0.03	0.02
Xylene	0.01	0.01
Naphthalene	0.01	0.01

* This limit makes 40 CFR §60.42b(k)(2) applicable and excludes the unit from limitations of 40 CFR §60.42b(k)(1). This limit satisfies the limitation in 45 CSR §10-3.1.b.

b. Boiler Aux-1 shall be fitted with Low NO_x burners and shall utilize Flue Gas Recirculation.

c. The permittee shall limit the annual capacity of the boiler to no more than 10 percent by limiting the annual average heat input of the boiler to 580,788 MMBtu per year. Compliance with this limit shall be satisfied though compliance with the annual fuel usage limit in item d of this condition.
[40 CFR §60.44b(c) and §63.7575; and 45 CSR §2-8.4.a.1.]

d. For the purpose of complying with the SO_2 limits in item a of this condition, the Boiler Aux-1 shall not consume more than 4,736 gallons of fuel oil (distillate oil) per hour nor more than 4,148,736 gallons per year. Such fuel oil can not contain more than 600 ppm or 0.06 % of

sulfur, which makes the sulfur dioxide potential for this unit at no greater than 0.06 lb/MMBtu.
[40 CFR §60.42.b(k)(2), §60.43b(h)(5), and §60.48b(j)(2); and 45 CSR §10-10.2]

e. Opacity from boiler shall not exceed 20% based on a 6-minute average, except for one 6-minute period per hour of not more than 27% opacity, except during periods of startup, shutdown, or malfunction.
[40 CFR §§60.43b(f) & (g)]

f. Visible emissions from the boiler shall not exceed 10 percent opacity based on a six minute block average, except during periods of startup, shutdown, or malfunction.
[45 CSR §2-3.1, and §2-9.1.]

g. The permittee shall conduct an initial tune-up of the unit before January 31, 2016 (40 CFR §63.7510(e)) and subsequent tune-ups once every 5 years thereafter in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. Subsequent tune-ups shall be conducted no later than 61 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 72 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 (you 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 maintain;

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]

5.1.2. **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.]

5.2. Monitoring Requirements

5.2.1. In order to determine compliance with Condition 5.1.1.d of this permit, the permittee shall monitor and record the amount of fuel oil combusted by Boiler Aux-1 on a monthly basis. Compliance with fuel usage limitations in item d will constitute compliance with the emission limitations of item a. of Condition 5.1.1. Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.49b(d)(2); and 45 CSR §2-8.3c., §§10-8.2.c.3., and 8.3.c.]

5.2.2. The permittee shall obtain records indicating the fuel oil received at the facility for Boiler Aux I meets the specification of distillate oil as defined in 40 CFR §60.41b and sulfur content stated in item d. of Condition 5.1.1. from the fuel supplier. Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.49b(r)(1) and 45 CSR §§10-8.2.c.3.]

5.2.3. The permittee shall conduct subsequent visible emission observations of the emission point for Boiler Aux-1 at least once every 12 months from the date of the most recent observation. Such observations be conducted using Method 9 of Appendix A-4 of Part 60. If visible emissions are observed, the permittee must follow the subsequent observation schedule in 40 CFR §60.48b(a)(1)(ii) through (iv) as applicable. Record of Method 9 observation shall contain the following:

a. Dates and time intervals of all opacity observation periods;

b. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

c. Copies of all visible emission observer opacity field data sheets;

If the most recent observation is less than 10 percent opacity, the permittee may use Method 22 of Appendix A-7 of Part 60 to demonstrate compliance in lieu of using Method 9. The use of Method 22 observations must be in accordance with the length of observation and frequency as outline in 40 CFR §60.48b(a)(2)(i) through (ii) as applicable. Record of Method 9 observation shall contain the following

a. Dates and time intervals of all visible emissions observation periods;

b. Name and affiliation for each visible emission observer participating in the performance test;

c. Copies of all visible emission observer opacity field data sheets; and

d. Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

Records of observations shall be maintained in accordance with Condition 3.4.1.
[40 CFR §§60.48b(a) and 60.49b(f); and 45 CSR §2-8.1(a)]

5.3. Testing Requirements

[Reserved]

5.4. Recordkeeping Requirements

5.4.1. **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.

5.4.2. **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.

5.4.3. **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.

5.4.4. The permittee shall keep the following records in accordance with 40CFR§63.7555. This includes but not limited to the following information during the tune up as required in Condition 4.1.1.g. and 40 CFR §63.7540:

a. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater. If concentrations of NO_x were taken during the tune-up of the unit, record of such measurements shall be included;

b. A description of any corrective actions taken as a part of the tune-up; and.
[40 CFR §§63.7540(a)(10)(vi) and 63.7555]

5.5. Reporting Requirements

5.5.1. The permittee shall submit a "Notification of Compliance Status" for Boiler Aux-1 to the Director before the close of business on the sixtieth (60th) day after completion of the initial compliance demonstration as required in 40 CFR §63.7530(f). Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the information specified in 40 CFR §§63.7545(e)(1), and (8), which included a statement the initial tune-up for boiler was completed. **[40CFR§63. 7530(d), and §63. 7545(e)]**

5.5.2. The permittee shall submit "5- year Compliance Reports" to the Director for Boiler Aux-1 with the first report being submitted by no later than January 31, 2016, and subsequent reports are due every 5 years from 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 biennial 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)]

5.5.3. The permittee shall report any observation made in accordance with Condition 5.2.3. that indicate visible emissions in excess of either items e and/or f of Condition 5.1.1. made during January 1 to June 30 in the facility's Title V Semi Annual Compliance Report or July 1 to December 31 as part of the facility's Title V Annual Compliance Report. Such report shall include the record of the recorded observation in accordance with Condition 5.2.3. and measures taken as result of the observation. This reporting requirement can be satisfied by including the results of the exceeded observation(s) with the facility's quarterly opacity report and list the exceedance in the facility's Title V annual compliance certification report.
[40 CFR §60.49b(h) and 45 CSR §2-8.3b.]

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.

West  ***Virginia Department of Environmental Protection***

Class II General Permit
G60-C Registration to Modify

for the
Prevention and Control of Air Pollution in regard to the
Construction, Modification, Relocation, Administrative Update and
Operation of Emergency Generators

The permittee identified at the facility listed below is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of General Permit G60-C.

G60-C057A

Issued to:

AEP Generation Resources Inc.
Mitchell Plant
051-00005

William F. Durham
Director

Issued: August 8, 2014

This Class II General Permit Registration will supercede and replace G60-C057.

Facility Location:	State Route 2, Moundsville, Marshall County, West Virginia
Mailing Address:	P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generation Facility
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Registration Type:	Modification
Description of Change:	Installation of two additional generators (EG-1 and EG-2) to black start the facility.

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 or registration 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.

Unless otherwise stated WVDEP DAQ did not determine whether the permittee is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart ZZZZ.

All registered facilities under Class II General Permit G60-C are subject to Sections 1.0, 2.0, 3.0, and 4.0.

The following sections of Class II General Permit G60-C apply to the registrant:

Section 5	Reciprocating Internal Combustion Engines (R.I.C.E.)	X
Section 6	Tanks	X
Section 7	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40CFR60 Subpart IIII)	X
Section 8	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (40CFR60 Subpart JJJJ)	X

Emission Units

Emission Unit ID	Emission Unit Description (Make, Model, Serial No.)	Year Installed	Design Capacity (Bhp/rpm)
LPG	Generac SG080, 127 BHP Engine (Spark Ignition Engine)	2013	127/1,800
EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	2014	3,717/1,800
EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	2014	3,004/1,800

Emission Limitations

Source ID#	Nitrogen Oxides		Carbon Monoxide		Volatile Organic Compounds	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
LPG	0.74	0.19	21.75	5.44	0.22	0.06
EG-1	59.9	14.98	7.66	1.92	0.94	0.24
EG-2	36.4	9.1	4.85	1.21	1.18	0.03
TOTAL	97.04	24.27	34.26	8.57	2.34	0.33

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Fwd: Wheeling Power transfer

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Thu, Mar 20, 2025 at 1:07 PM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>, Laura M Crowder <laura.m.crowder@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>, Megan E Grose <megan.e.grose@wv.gov>, Kimberly A Scott <kimberly.a.scott@wv.gov>

Hey. I called Matt Palmer who is the Plant Environmental Coordinator at the Mitchell Power Plant this morning to see if he had any information regarding the proposed name change from Kentucky Power Company to Wheeling Power Company that originated in 2022. Mr. Palmer consulted with Brandon Belcher who is the Environmental Specialist Sr. at AEP Service Corporation in Columbus, OH. Mr. Palmer found an email and sent it to me and I forwarded it to you all. It confirms that there was a name change request and fee submitted, but it was later determined that there was no need to transfer the air permits from Kentucky Power Company at that time. FYI... the transfer of the Kentucky Power portion to Liberty fell through and never happened.

Mr. Palmer also stated that they would probably go ahead and submit new paperwork to transfer the name to Wheeling Power Company in the near future.

I hope this clears things up with all parties involved. Feel free to respond if anyone has any further questions.

Thanks for everyone's time and effort on this!

Thanks again,
Dan

---------- Forwarded message ---------
From: **G M Palmer** <gmpalmer@aep.com>
Date: Thu, Mar 20, 2025 at 11:54 AM
Subject: Wheeling Power transfer
To: Daniel.P.Roberts@wv.gov <Daniel.P.Roberts@wv.gov>
Cc: Brandon T Belcher <btbelcher@aep.com>

Email info below.

G M Palmer

From: Gregory J Wooten
Sent: Tuesday, September 6, 2022 8:33 PM
To: Douglas J Rosenberger
Cc: Todd A March; Jeffrey D Clark; G M Palmer
Subject: FW: Mitchell Transfer from Kentucky to Wheeling Power Company

Doug,
After a recent discussion with WVDEP, it became unnecessary to transfer the Title V Permit and the Class II General Air Permit.

Last week, I spoke with the WVDEP Air Director (Laura Crowder) about the Mitchell Permit transfers from Kentucky Power to Wheeling Power. Laura had also spoken with the WVDEP legal department just to confirm that her position was correct.

She indicated that in this situation, there is no need to transfer the air permits. She explained that under the air regulations, WVDEP has the option to issue the permits either in the name of the owner or the operator. Because Kentucky Power will still be one of the owners (until the liberty transfer), there is no need to transfer the permits out of Kentucky Power. She mentioned that if the Designated Representative (Scott Weaver) or the plant responsible official (plant manager) was changing, then those changes would need to be made. Since neither are changing, there is nothing to change.

She did indicate that we will need to submit a request for ownership transfer when the Kentucky power portion is transferred to Liberty. Laura said they have records of the fee we paid for the original transfer request, so there will be no need to pay an additional fee when the ownership transfer occurs.

Greg

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY
GREGORY J WOOTEN | ENVIRONMENTAL ENGINEER STAFF
GJWOOTEN@AEP.COM | A:8.200.1262
1 RIVERSIDE PLAZA, COLUMBUS, OH 43215

Thanks,

AMERICAN ELECTRIC POWER
G M PALMER | ENVIRONMENTAL COORD PRIN
GMPALMER@AEP.COM | D:304.843.6048 | C:304.559.4538
8999 ENERGY ROAD, MOUNDSVILLE, WV 26041

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Draft/Proposed Permit and Fact Sheet for Kentucky Power Company's Mitchell Plant - R30-05100005-2025

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Thu, Mar 20, 2025 at 12:36 PM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

Carrie,

Hey. Here is the draft proposed permit for your review. I am working on cleaning up and double checking the fact sheet and will send it shortly.

Matt Palmer got back to me and confirmed that there was never an official acknowledged name change from Kentucky to Wheeling Power. I will forward the copy of an email which he sent me that ties this up. So, the documents will use Kentucky Power Company at this time, but he said they may submit the name change forms in the near future (probably before the comment period expires).

Thanks,
Dan

Draft Permit R30-05100005-2025 3-20-25.docx
2065K

West Virginia Department of Environmental Protection
Harold D. Ward
Cabinet Secretary

Permit to Operate

Pursuant to

Title V

of the Clean Air Act

Issued to:

Kentucky Power Company
Mitchell Plant
R30-05100005-2025

Laura M. Crowder
Director, Division of Air Quality

Issued: [Date of issuance] • Effective: [Equals issue date plus two weeks]
Expiration: [5 years after issuance date] • Renewal Application Due: [6 months prior to expiration]

Permit Number: **R30-05100005-2019**
Permittee: **Kentucky Power Company (d.b.a. American Electric Power)**
Facility Name: **Mitchell Plant**
Permittee Mailing Address: **1 Riverside Plaza, Columbus, Ohio 43215-2373**

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45CSR30 C Requirements for Operating Permits. The permittee identified at the above-referenced facility is authorized to operate the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Facility Location:	Cresap/Moundsville, Marshall County, West Virginia
Facility Mailing Address:	Post Office Box K, Moundsville, West Virginia 26041
Telephone Number:	304-843-6000
Type of Business Entity:	Corporation
Facility Description:	Electric Generation Service
SIC Codes:	Primary 4911; Secondary N/A; Tertiary N/A
UTM Coordinates:	516.00 km Easting $ 4409.00 km Northing $ Zone 17

Permit Writer: Dan Roberts

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.

Issuance of this Title V Operating Permit does not supersede or invalidate any existing permits under 45CSR13, 14 or 19, although all applicable requirements from such permits governing the facility's operation and compliance have been incorporated into the Title V Operating Permit.

Table of Contents

1.0 Emission Units and Active R13, R14, and R19 Permits

1.1. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed [1]	Design Capacity [2]	Control Device [3]
Boilers & Associated Equipment					
Unit 1	1E	Boiler: Foster Wheeler, Model # 2-85-303	1971	7020 mmBtu/hr	High efficiency ESP, LNB, SCR, FGD
Unit 2	2E	Boiler: Foster Wheeler, Model # 2-85-304	1971	7020 mmBtu/hr	High efficiency ESP, LNB, SCR, FGD
Aux 1	Aux ML1	Boiler: Foster Wheeler, Model # SD-25	1970	663 mmBtu/hr	FGR/LNB
17S	17E	Unit 1 Emergency Diesel Driven Fire Pump Engine – 2023 Cummins CFP7E-F60 Certificate No. PCEXL0409AAB-006 (Tier 3)	2023	249 hp	None
18S	18E	Unit 2 Emergency Diesel Driven Fire Pump Engine – 2024 Cummins CFP9E-F10 Certificate No. RCEXL0540AAB-009 (Tier 3)	2024	275 hp	None
EG-1	EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	2014	3,717 bhp @ 1,800rpm	None
EGT01	EGT01	Diesel Fuel Storage Tank for EG-1	2014	4,800 gallons	None
EG-2	EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	2014	3,004 bhp @ 1,800rpm	None
EGT02	EGT02	Diesel Fuel Storage Tank for EG-2	2014	4,800 gallons	None
LF DEG	LF DEG	Landfill Leachate Collection Sump Emergency Diesel Driven Generator, 2019 Cummings C300DQDAC model	2020	464 bhp 300 kW	None
LF DEGT	LF DEGT	Diesel Fuel Storage Tank for LF DEG	2020	600 gallons	None
LF DEG2	LF DEG2	Landfill Leachate Pond Diesel Emergency Generator, 2023 Cummins QSG12 Model Certificate No. PCEXL12.0AAA-049 (Tier 3)	2023	513 bhp 400 kW	None
LF DEGT2	LF DEGT2	Diesel Fuel Storage Tank for LF DEG2	2023	600 gallons	None
Coal & Ash Handling					
BU	BU	Barge Unloader (unload barge onto Conveyor R1	1971	4,000 TPH	WS, PE, MC
Station R1	Sta-R1	Conveyor R1 and drop points to Conveyor R2	1971	3,000 TPH	FE, MC
C-R2	C-R2	Conveyor R2 (transfer to Station R2)	1971	3,000 TPH	WS, PE, MC
RCU	RCU	Rail Car Unloader (unload rail cars to feeders R6-1, R6-2 and R6-3)	April, 1974	3,000 TPH	WS, MC

R6-1, R6-2, R6-3	R6-1, R6-2, R6-3	Feeders R6-1, R6-2, R6-3 (transfer points to Conveyor R7)	April 1974	1,400 TPH	PE, MC
C-R7	C-R7	Conveyor R7 (transfer to Station R2)	April 1974	3,000 TPH	WS, PE, MC
Station R2	Sta-R2	Drop point to coal crusher or conveyor R3	April 1974	N/A	FE, MC
CR-R2	CR-R2	Coal Crusher	1971	2,500 TPH	FE, MC
C-R3	C-R3	Conveyor R3 (transfer to Station R3)	1971	3,000 TPH	PE, MC
Station R3	Sta-R3	Drop point to conveyor R4 or R11	1971	N/A	FE, MC
C-R11	C-R11	Conveyor R11 (transfer to radial portable Conveyor R12)	1971	3,000 TPH	PE, MC
C-R12	C-R12	Radial Portable Conveyor R12 (transfer to temporary storage pile)	1971	3,000 TPH	MC
C-R4	C-R4	Conveyor R4 (transfer to Station R4)	1971	3,000 TPH	PE, MC
Station R4	Sta-R4	Drop point to Sample System and Conveyor R5; and/or Conveyor R8	1971	N/A	FE, MC
C-R8	C-R8	Conveyor R8 (transfer to Radial Stacker Conveyor R9)	April 1974	3,000 TPH	PE, MC
C-R9	C-R9	Radial Stacker Conveyor R9 (transfer to North Yard Storage Pile – Station R7)	April 1974	3,000 TPH	MC
Station R7	Sta-R7	Drop point from North Yard Storage Pile through Crusher R7-1 to Feeder Conveyor BFR7-1	April 1974	N/A	FE, MC
CR-R7-1	CR-R7-1	Coal Crusher	April 1974	1,000 TPH	FE, MC
BFR7-1	BFR7-1	Feeder BFR7-1 (transfer to Conveyor R10)	April 1974	1,100 TPH	FE, MC
C-R10	C-R10	Conveyor R10 (transfer to truck load out and Station R4)	April 1974	1,100 TPH	PE, MC
C-R5	C-R5	Conveyor R5 (transfer to Drive Tower S1)	1971	3,000 TPH	PE, MC
Drive Tower S1	Drive Tower S1	Drop point to Conveyor R6	1971	N/A	FE, MC
C-R6	C-R6	Conveyor R6 (transfer to Station 2)	1971	3,000 TPH	PE, MC
Station 2	Sta-2	Drop point to Radial Stacker Conveyor 2	1969	N/A	FE, MC
RS-2	RS-2	Radial Stacker 2 (transfer to surge pile)	1969	4,000 TPH	WS, MC
Station 1A	Sta-1A	Drop point from frozen coal storage area 4 through crusher CR-1A to Conveyor 1A	1969	N/A	FE, MC
CR-1A	CR-1A	Coal Crusher	1969	1,000 TPH	FE, MC
C-1A	C-1A	Conveyor 1A (transfer to Station 1B)	1969	1,100 TPH	PE, MC
Station 1B	Sta-1B	Drop point to Conveyor 1	1969	N/A	FE, MC
C-1	C-1	Conveyor 1 (transfer to Station 2)	1969	2,600 TPH	PE, MC
CSA-1	CSA-1	Coal Storage Area #1 (Surge Pile)	1969	Approx. 40 Acres	MC
CSA-2	CSA-2	Coal Storage Area #2 (North Yard Storage Pile)	April 1974	Approx. 40 Acres	MC
CSA-3	CSA-3	Coal Storage Area #3 (Temporary Storage Pile at R3)		Approx. 6 Acres	MC

CSA-4	CSA-4	Coal Storage Area #4 (conveyor from 1B)	1969	Included in CSA-1	MC
SGM1 through SGM16	SGM1 through SGM16	Reclaim Hoppers/Vibratory Feeders (Reclaim Area #1 surge pile) transfers to Conveyors 3A, 3B and 3C	1969	300 TPH each	FE, MC
C-3A	C-3A	Conveyor 3A (transfer to Station 3B)	1969	1,100 TPH	FE, MC
Station 3B	Sta-3B	Drop point to Conveyor 3B	1969	N/A	FE, MC
C-3B	C-3B	Conveyor 3B (transfer to Station 3)	1969	1,100 TPH	FE, MC
C-3C	C-3C	Conveyor 3C (transfer to Station 3)	1969	1,100 TPH	FE, MC
Station 3	Sta-3	Drop point to Conveyors 4E and/or 4W	1969	N/A	FE, MC
C-4E / C-4W	C-4E / C-4W	Conveyors 4E and 4W (transfer to Station 4)	1969	1,100 TPH each	PE, MC
Station 4	Sta-4	Drop point to Sample System, Conveyor 7E and/or 7W, and Conveyor 5 or Emergency Conveyors E25 through E21	1969	N/A	FE, MC
C-7E / C-7W	C-7E / C-7W	Conveyors 7E and 7W (transfer to Station 5)	1969	1,100 TPH each	PE, MC
C-5	C5	Conveyor 5 (transfer to Unit 2 coal silos 3, 4 or 5 and to Conveyor 6)	1969	1,100 TPH	FE, MC
C-6	C-6	Conveyor 6 (transfer to Unit 2 coal silos 1 or 2)	1969	1,100 TPH	FE, MC
C-E25 through C-E21	C-E25 through C-E21	Emergency conveyors E25 through E21 (used in an emergency to transfer coal into Unit 2 coal silos)	1969	500 TPH each	MC
Station 5	Sta-5	Drop point to Conveyor 8 or Emergency Conveyors E11 through E15	1969	N/A	FE, MC
C-8	C-8	Conveyor 8 (transfer to Unit 1 coal silos 3, 4, or 5 and to Conveyor 9)	1969	1,100 TPH	FE, MC
C-9	C-9	Conveyor 9 (transfer to Unit 1 coal silos 1 or 2)	1969	1,100 TPH	FE, MC
C-E11 through C-E15	C-E11 through C-E15	Emergency conveyors E11 through E15 (used in an emergency to transfer coal into Unit 1 coal silos)	1969	500 TPH	MC
Fly Ash Material Handling					
Haul Roads	Haul Roads	Fly Ash Material Haul Roads and Landfill	N/A	N/A	Water Truck
ME-1A	EP-1	Unit 1 Mechanical Exhauster 1A	2012	N/A	Filter/ Separator
ME-1B	EP-2	Unit 1 Mechanical Exhauster 1B	2012	N/A	Filter/ Separator
ME-1C (spare)	EP-3	Unit 1 Mechanical Exhauster 1C	2012	N/A	Filter/ Separator
ME-2A	EP-4	Unit 2 Mechanical Exhauster 2A	2012	N/A	Filter/ Separator
ME-2B	EP-5	Unit 2 Mechanical Exhauster 2B	2012	N/A	Filter/ Separator
ME-2C (spare)	EP-6	Unit 2 Mechanical Exhauster 2C	2012	N/A	Filter/ Separator
FAS-A	EP-7	Fly Ash Silo A	2012	2,160 tons	BVF-A
FAS-B	EP-8	Fly Ash Silo B	2012	2,160 tons	BVF-B

FAS-C	EP-9	Fly Ash Silo C	Future	2,160 tons	BVF-C
WFA-AA	F-1	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-BA	F-2	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-CA	F-3	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	Future	360 tph	MC
WFA-AB (spare)	F-4	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-BB (spare)	F-5	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	2012	360 tph	MC
WFA-CB (spare)	F-6	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	Future	360 tph	MC
TC-A	EP-10, F-7	Transfer dry fly ash from Fly Ash Silo A to Truck via Telescopic Chute	2012	300 tph	TC
TC-B	EP-11, F-8	Transfer dry fly ash from Fly Ash Silo B to Truck via Telescopic Chute	2012	300 tph	TC
TC-C	EP-12, F-9	Transfer dry fly ash from Fly Ash Silo C to Truck via Telescopic Chute	Future	300 tph	TC
LPG	LPG	Generac SG080, Lean Burn Four Stroke, Liquid Propane Gas-fired emergency generator Certificate No. DGNXB08.92NL-011	2013	126 bhp	None
LPT	LPT	Liquid Propane tank for LPG	2013	500 gallons	None
1S – Limestone Material Handling					
BUN-1	BUN-1 (Fugitive)	Limestone Unloading Crane	2006	1,000 TPH	None
RH-1	RH-1 (Fugitive)	Limestone Unloading Hopper	2006	60 Tons	WS, PE
VF-1	VF-1 (Fugitive)	Limestone Unloading Feeder	2006	750 TPH	FE
BC-1	BC-1 (Fugitive)	Limestone Dock/Connecting Conveyor	2006	750 TPH	PE
TH-1	TH-1 (Fugitive)	Limestone Transfer House #1	2006	750 TPH	FE
BC-2	BC-2 (Fugitive)	Limestone Storage Pile Stacking Conveyor	2006	750 TPH	PE
LSSP	LSSP (Fugitive)	Limestone Active/Long-Term Stockpile	2006/2011	155,000 Tons	None
2S – Gypsum Material Handling					
BC-8	BC-8 (Fugitive)	Vacuum Collecting Conveyor	2007	200 TPH	PE
TH-3	TH-3 (Fugitive)	Gypsum Transfer House #3	2007	200 TPH	FE
BC-9	BC-9 (Fugitive)	Connecting Conveyor	2007	200 TPH	PE
TH-4	TH-4 (Fugitive)	Gypsum Transfer House #4	2007	200 TPH	FE

BC-10	BC-10 (Fugitive)	Connecting Conveyor	2007	200 TPH	PE
TH-5	TH-5 (Fugitive)	Gypsum Transfer House #5	2007	200 TPH	FE
BC-11	BC-11 (Fugitive)	Connecting Conveyor	2007	200 TPH	PE
TH-6	TH-6 (Fugitive)	Gypsum Transfer House #6	2007	200 TPH	FE
BC-12	BC-12 (Fugitive)	Stacking Tripper Conveyor	2007	200 TPH	PE
GSP	GSP (Fugitive)	Gypsum Stockpile	2007	15,600 tons	FE
PSR-1	PSR-1 (Fugitive)	Traveling Portal Scraper Reclaimer	2007	1,000 TPH	FE
BC-14	BC-14 Fugitive)	Reclaim Conveyor	2007	1,000 TPH	PE
TH-7	TH-7 (Fugitive)	Transfer House #7	2007	1,000 TPH	FE
BC-13	BC-13 (Fugitive)	Bypass Conveyor	2007	200 TPH	PE
BC-15	BC-15 (Fugitive)	Connecting Conveyor	2007	1,000 TPH	PE
TH-1	TH-1 (Fugitive)	Transfer House #1	2007	1,000 TPH	FE
BC-16	BC-16 (Fugitive)	Transfer Conveyor	2007	1,000 TPH	PE
BL-1	BL-1 (Fugitive)	Barge Loader	2007	1,000 TPH	PE
BC-14	BC-14 (Fugitive)	Reclaim Conveyor Extension	2007	1,000 TPH	PE
TH-8	TH-8 (Fugitive)	Transfer House 8	2007	1,000 TPH	FE
BC-19	BC-19 (Fugitive)	Transfer Conveyor	2007	1,000 TPH	PE
TH-9	TH-9 (Fugitive)	Transfer House 9	2007	1,000 TPH	FE
BC-20	BC-20 (Fugitive)	Transfer Conveyor to 20	2007	1,000 TPH	PE
TH-10	TH-10 (Fugitive)	Transfer House 10	2007	1,000 TPH	FE
BC-21	BC-21 (Fugitive)	Transfer Conveyor to 21	2007	1,000 TPH	PE
BUN-1	BUN-1 (Fugitive)	Clamshell Unloading Crane	2007	1,000 TPH	
RH-4	RH-4 (Fugitive)	Gypsum Unloading Hopper	2007	30 tons	WS, PE
RP-1	RP-1 (Fugitive)	Gypsum Rotary Plow	2007	750 TPH	FE
BC-17	BC-17 (Fugitive)	Dock/Connecting Conveyor	2007	750 TPH	PE

TH-7	TH-7 (Fugitive)	Transfer House #7	2007	750 TPH	FE
BC-18	BC-18 (Fugitive)	Bypass Conveyor	2007	750 TPH	PE
TH-6	TH-6 (Fugitive)	Transfer House #6	2007	750 TPH	FE
3S – Limestone Mineral Processing					
VF-2	VF-2 (Fugitive)	Limestone Reclaim Feeder 2	2007	750 TPH	FE
VF-3	VF-3 (Fugitive)	Limestone Reclaim Feeder 3	2007	750 TPH	FE
BC-3	BC-3 (Fugitive)	Limestone Tunnel Reclaim Conveyor	2007	750 TPH	PE
FB-1	FB-1 (Fugitive)	Emergency Limestone Reclaim Feeder/Breaker	2007	750 TPH	
TH-2	TH-2 (Fugitive)	Limestone Transfer House 2	2007	750 TPH	FE
BC-4	BC-4 (Fugitive)	Limestone Silo A Feed Conveyor	2007	750 TPH	PE
BC-5	BC-5 (Fugitive)	Limestone Silo B Feed Conveyor	2007	750 TPH	PE
BC-6	BC-6 (Fugitive)	Limestone Silo C Feed Conveyor (future)	2007	750 TPH	PE
LSB-1	6E	Limestone Silo A	2007	900 Tons	BH
LSB-2	7E	Limestone Silo B	2007	900 Tons	BH
LSB-3	8E	Limestone Silo C (future)	Future	900 Tons	BH
	(Fugitive)	Vibrating Bin Discharger (one per silo)	2007	68.4 TPH	FE
LSWF-1 LSWF-2 LSWF-3	LSWF-1 (Fugitive) LSWF-2 (Fugitive) LSWF-3 (Fugitive)	Limestone Weigh Feeder (one per silo)	2007	68.4 TPH	FE
	(Fugitive)	Wet Ball Mill (one per silo)	2007	68.4 TPH	FE
4S – Dry Sorbent Material Handling					
	(Fugitive)	Truck Unloading Connection (2)	2007	25 TPH	FE
DSSB 1	10E	Dry Sorbent Storage Silo #1	2007	500 TPH	BH, FE
DSSB 2	11E	Dry Sorbent Storage Silo #2	2007	500 TPH	BH, FE
	(Fugitive)	Aeration Distribution Bins	2007	4.6 TPH	FE
	(Fugitive)	De-aeration Bins	2007	4.6 TPH	FE
	(Fugitive)	Rotary Feeder	2007	4.6 TPH	FE
5S – Coal Blending System					
HTS-1	HTS-1 (Fugitive)	Transfer House #1	2007	3,000 TPH	FE
HSC-1	HSC-1 (Fugitive)	Stacking Conveyor #1	2007	3,000 TPH	PE

HTS-2A	HTS-2A (Fugitive)	Transfer House #2A	2007	3,000 TPH	FE
HSC-2	HSC-2 (Fugitive)	Stacking Conveyor #2	2007	3,000 TPH	PE
HTS-3	HTS-3 (Fugitive)	Transfer House #3	2007	3,000 TPH	FE
HSC-3	HSC-3 (Fugitive)	Stacking Conveyor #3	2007	3,000 TPH	PE
SH-1	SH-1 (Fugitive)	Stacking Hopper SH-1 Transfer to SC-3 (receive coal from plant radial stacker R9)	2007	3,000 TPH	FE
HSC-3 to High Sulfur Pile (CSA-2, existing)	HSC-3 to High Sulfur Pile (Fugitive) (CSA-2, existing)	Transfer from Stacking Conveyor HSC-3 to High Sulfur Pile at existing North Yard Storage Area (CSA-2)	2007	3,000 TPH	Stacking Tube
HVF-1	HVF-1 (Fugitive)	Coal Reclaim Feeder 1	2007	800 TPH	FE
HVF-2	HVF-2 (Fugitive)	Coal Reclaim Feeder 2	2007	800 TPH	FE
HVF-3	HVF-3 (Fugitive)	Coal Reclaim Feeder 3	2007	800 TPH	FE
HVF-4	HVF-4 (Fugitive)	Coal Reclaim Feeder 4	2007	800 TPH	FE
HVF-1 through HVF-4 to HRC-1 (Transfer)	HVF-1 through HVF-4 to HRC-1 (Fugitive) (Transfer)	Transfer from Vibrating Feeders HVF-1 through HVF-4 to Reclaim Conveyor HRC-1	2007	1,600 TPH	FE
HRC-1	HRC-1 (Fugitive)	Coal Tunnel Reclaim Conveyor	2007	1,600 TPH	PE
HTS-2B	HTS-2B (Fugitive)	Coal Transfer House #2B	2007	1,600 TPH	FE
HRC-2	HRC-2 (Fugitive)	Reclaim Conveyor #2	2007	1,600 TPH	PE
HTS-4	HTS-4 (Fugitive)	Coal Transfer House #4	2007	1,600 TPH	FE
HRC-3	HRC-3 (Fugitive)	Reclaim Conveyor #3	2007	1,600 TPH	PE
HTS-5	HTS-5 (Fugitive)	Coal Transfer House #5	2007	1,600 TPH	FE
SB-1	SB-1 (Fugitive)	Surge Bin #1	2007	80 Tons	FE
HBF-1A	HBF-1A (Fugitive)	Belt Feeder 1A	2007	800 TPH	PE
HBF-1B	HBF-1B (Fugitive)	Belt Feeder 1B	2007	800 TPH	PE
HBF-1A/1B to BF-4E/4W	HBF-1A/1B to BF-4E/4W (Fugitive)	Transfer from Belt Feeders HBF-1A and HBF-1B to Existing Coal Conveyors 4E and 4W	2007	1,600 TPH	FE

6S, 7S – Emergency Quench Water System

6S	15E	Diesel Engine on Quench Pump #1	2007[1]		

				60 HP (approx.)	FE
7S	16E	Diesel Engine on Quench Pump #2	2007 [2]	60 HP (approx.)	FE
9S – Magnesium Hydroxide Material Handling System					
MHM-1	MHM-1	Magnesium Hydroxide Mix Tank #1	2007	1,000 gallons	N/A
MHM-2	MHM-2	Magnesium Hydroxide Mix Tank #2	2007	1,000 gallons	N/A

[1] Construction *commenced* (as defined in 40 C.F.R. §63.2) on or about June 14, 2004 for engine 6S.
[2] Construction *commenced* (as defined in 40 C.F.R. §63.2) on or about June 14, 2004 for engine 7S.

Tank #28	Tank #28	Diesel Fire Pump Fuel Tank – U1	2023	300 gallons	N/A
Tank #29	Tank #29	Diesel Fire Pump Fuel Tank – U2	2024	300 gallons	N/A
Tank #30	Tank #30	3 Compartment Oil Tank – Tractor Shed Oil Room	~1995	920 gallons	N/A
Tank #31	Tank #31	Single Compartment Oil Tank – Tractor Shed	~1995	560 gallons	N/A
Tank #33	Tank #33	Urea Receiving Hopper	2007	45 tons	FE
Tank #34	Tank #34	No.2 Fuel Oil Tank – Drain Receiver Tank – overflow tank	2001	1,000 gallons	N/A
Tank #35	Tank #35	TK103-100 Urea Solution Storage Tank	2007	200,000 gallons	N/A
Tank #36	Tank #36	TK102-100 Urea Mix Tank	2007	2,700 gallons	N/A
Tank #37	Tank #37	CPS Lime Slurry Tank #1	2007	750 gallons	N/A
Tank #38	Tank #38	CPS Lime Slurry Tank #2	2007	750 gallons	N/A
Tank #39	Tank #39	CPS Equalization Tank #1	2007	254,513 gallons	N/A
Tank #40	Tank #40	CPS Equalization Tank #2	2007	254,513 gallons	N/A
Tank #41	Tank #41	CPS Ferric Chloride Mix Tank #1	2007	9,200 gallons	N/A
Tank #42	Tank #42	CPS Ferric Chloride Mix Tank #2	2007	9,200 gallons	N/A
Tank #43	Tank #43	CPS Ferric Chloride Bulk Storage Tank	2007	8,800 gallons	N/A
Tank #45	Tank #45	CPS Polymer Totes (2)	2007	225 gallons each	N/A
Tank #46	Tank #46	Emergency Quench Pump #1 Diesel Tank	2007	70 gallons	N/A
Tank #47	Tank #47	Emergency Quench Pump #2 Diesel Tank	2007	70 gallons	N/A
Tank #49	Tank #49	No. 2 Fuel Tank – SW Corner of CSA-2	2008	2000 gallons	N/A
Tank #50	Tank #50	Gypsum Storage Building Fuel Oil Tank	2009	1,000 gallons	None
Tank #51	Tank #51	Highway Grade Diesel Tank #1	2011	1,000 gallons	None
Tank #52	Tank #52	Limestone Storage Pile Diesel Tank #1	2011	500 gallons	None
	Fugitive	Rock Salt Storage Pile (roadway ice control)	2010 and 2014	600 tons	Enclosure
Tank #53	Tank #53	Landfill Building Furnace Fuel Oil Tank	2018	2,000 gallons	N/A
Tank #54	Tank #54	Landfill Gasoline Tank	2018	520 gallons	N/A
Tank #55	Tank #55	Kerosene Tank	2015	1,000 gallons	N/A
Tank #56	Tank #56	CPS Coagulant Tank	2019	5,000 gallons	N/A
Tank #57	Tank #57	Unit 1 Scale Inhibitor Tank	2015	3,500 gallons	N/A
Tank #58	Tank #58	Unit 2 Scale Inhibitor Tank	2015	3,500 gallons	N/A
Tank #59	Tank #59	Unit 1 Dispersant Tank	2015	5,000 gallons	N/A
Tank #60	Tank #60	Unit 2 Dispersant Tank	2015	5,000 gallons	N/A
Tank #61	Tank #61	Unit 1 Ferric Chloride Tank	2015	1,500 gallons	N/A
Tank #62	Tank #62	Unit 1 Ferric Chloride Tank	2015	2,500 gallons	N/A
Tank #63	Tank #63	FGD corrosion inhibitor tank	2015	5,000 gallons	N/A
		Landfill Building Fuel Oil Fired Furnace Clean Burn Model CB-3250	2018	0.325 MMBtu/hr	None
Tank #64	Tank #64	Bioreactor Nutrient Tank	2024	12,575 gallons	N/A

Tank #65	Tank #65	Bioreactor Hydrochloric Acid Tank	2024	6,000 gallons	N/A
Tank #66	Tank #66	WW Pond Sulfuric Acid Tank	2023	14,500 gallons	N/A
Tank #67	Tank #67	WW Pond Sodium Hydroxide Tank	2023	20,300 gallons	N/A
Tank #68	Tank #68	WW Pond Organosulfide Tank	2023	6,400 gallons	N/A
Tank #69	Tank #69	WW Pond Polymer Tank	2023	1,360 gallons	N/A

“Year Installed” reflects the “commenced” construction or modification date as defined in 40 C.F.R. Part 60.

[2] Rated Design Capacity

[3] Control Device/Control System abbreviations: ESP = Electrostatic Precipitators, LNB = Low NOx Burners, SCR = Selective Catalytic Reduction, FGD = Flue Gas Desulfurization, FE = Full enclosure, PE = Partial Enclosure, BH = Baghouse(s), MC = Moisture Content, WS = Wetting Spray, TC = Telescopic Chute, BVF = Bin Vent Filter, TS = Vacuum/Pressure Transfer Stations, N/A = Not applicable

1.2. Active R13, R14, and R19 Permits

The underlying authority for any conditions from R13, R14, and/or R19 permits contained in this operating permit is cited using the original permit number (e.g. R13-1234). The current applicable version of such permit(s) is listed below.

Permit Number	Date of Issuance
R13-2608E	May 8, 2014
G60-C057A	August 8, 2014
Phase II Acid Rain Permit # R33-3948-2027-6	December 19, 2022

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 other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.39.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.1.4. Unless otherwise specified in a permit condition or underlying rule or regulation, all references to a "rolling yearly total" shall mean the sum of the monthly data, values or parameters being measured, monitored, or recorded, at any given time for the previous twelve (12) consecutive calendar months.

2.2. Acronyms

CAAA	Clean Air Act Amendments
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
C.F.R. *or* CFR	Code of Federal Regulations
CO	Carbon Monoxide
C.S.R. *or* CSR	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
FOIA	Freedom of Information Act
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr *or* lb/hr	Pounds per Hour
LDAR	Leak Detection and Repair
m	Thousand
MACT	Maximum Achievable Control Technology
mm	Million
mmBtu/hr	Million British Thermal Units per Hour
mmft^3/hr *or* mmcf/hr	Million Cubic Feet Burned per Hour
NA *or* N/A	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10µm in diameter
pph	Pounds per Hour
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
VOC	Volatile Organic Compounds

2.3. Permit Expiration and Renewal

2.3.1. Permit duration. This permit is issued for a fixed term of five (5) years and shall expire on the date specified on the cover of this permit, except as provided in 45CSR§30-6.3.b. and 45CSR§30-6.3.c.
[45CSR§30-5.1.b.]

2.3.2. A permit renewal application is timely if it is submitted at least six (6) months prior to the date of permit expiration.
[45CSR§30-4.1.a.3.]

2.3.3. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with 45CSR§30-6.2. and 45CSR§30-4.1.a.3.
[45CSR§30-6.3.b.]

2.3.4. If the Secretary fails to take final action to deny or approve a timely and complete permit application before the end of the term of the previous permit, the permit shall not expire until the renewal permit has been issued or denied, and any permit shield granted for the permit shall continue in effect during that time.
[45CSR§30-6.3.c.]

2.4. Permit Actions

2.4.1. This permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
[45CSR§30-5.1.f.3.]

2.5. Reopening for Cause

2.5.1. This permit shall be reopened and revised under any of the following circumstances:

a. Additional applicable requirements under the Clean Air Act or the Secretary's legislative rules become applicable to a major source with a remaining permit term of three (3) or more years. Such a reopening shall be completed not later than eighteen (18) months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 45CSR§§30-6.6.a.1.A. or B.

b. Additional requirements (including excess emissions requirements) become applicable to an affected source under Title IV of the Clean Air Act (Acid Deposition Control) or other legislative rules of the Secretary. Upon approval by U.S. EPA, excess emissions offset plans shall be incorporated into the permit.

c. The Secretary or U.S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

d. The Secretary or U.S. EPA determines that the permit must be revised or revoked and reissued to assure compliance with the applicable requirements.

[45CSR§30-6.6.a.]

2.6. Administrative Permit Amendments

2.6.1. The permittee may request an administrative permit amendment as defined in and according to the procedures specified in 45CSR§30-6.4.
[45CSR§30-6.4.]

2.7. Minor Permit Modifications

2.7.1. The permittee may request a minor permit modification as defined in and according to the procedures specified in 45CSR§30-6.5.a.
[45CSR§30-6.5.a.]

2.8. Significant Permit Modification

2.8.1. The permittee may request a significant permit modification, in accordance with 45CSR§30-6.5.b., for permit modifications that do not qualify for minor permit modifications or as administrative amendments.
[45CSR§30-6.5.b.]

2.9. Emissions Trading

2.9.1. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit and that are in accordance with all applicable requirements.
[45CSR§30-5.1.h.]

2.10. Off-Permit Changes

2.10.1. Except as provided below, a facility may make any change in its operations or emissions that is not addressed nor prohibited in its permit and which is not considered to be construction nor modification under any rule promulgated by the Secretary without obtaining an amendment or modification of its permit. Such changes shall be subject to the following requirements and restrictions:

a. The change must meet all applicable requirements and may not violate any existing permit term or condition.

b. The permittee must provide a written notice of the change to the Secretary and to U.S. EPA within two (2) business days following the date of the change. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the permit shield.

d. The permittee shall keep records describing all changes made at the source that result in emissions of regulated air pollutants, but not otherwise regulated under the permit, and the emissions resulting from those changes.

e. No permittee may make any change subject to any requirement under Title IV of the Clean Air Act (Acid Deposition Control) pursuant to the provisions of 45CSR§30-5.9.

f. No permittee may make any changes which would require preconstruction review under any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) pursuant to the provisions of 45CSR§30-5.9.

[45CSR§30-5.9.]

2.11. Operational Flexibility

2.11.1. The permittee may make changes within the facility as provided by § 502(b)(10) of the Clean Air Act. Such operational flexibility shall be provided in the permit in conformance with the permit application and applicable requirements. No such changes shall be a modification under any rule or any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) promulgated by the Secretary in accordance with Title I of the Clean Air Act and the change shall not result in a level of emissions exceeding the emissions allowable under the permit.
[45CSR§30-5.8]

2.11.2. Before making a change under 45CSR§30-5.8., the permittee shall provide advance written notice to the Secretary and to U.S. EPA, describing the change to be made, the date on which the change will occur, any changes in emissions, and any permit terms and conditions that are affected. The permittee shall thereafter maintain a copy of the notice with the permit, and the Secretary shall place a copy with the permit in the public file. The written notice shall be provided to the Secretary and U.S. EPA at least seven (7) days prior to the date that the change is to be made, except that this period may be shortened or eliminated as necessary for a change that must be implemented more quickly to address unanticipated conditions posing a significant health, safety, or environmental hazard. If less than seven (7) days notice is provided because of a need to respond more quickly to such unanticipated conditions, the permittee shall provide notice to the Secretary and U.S. EPA as soon as possible after learning of the need to make the change.
[45CSR§30-5.8.a.]

2.11.3. The permit shield shall not apply to changes made under 45CSR§30-5.8., except those provided for in 45CSR§30-5.8.d. However, the protection of the permit shield will continue to apply to operations and emissions that are not affected by the change, provided that the permittee complies with the terms and conditions of the permit applicable to such operations and emissions. The permit shield may be reinstated for emissions and operations affected by the change:

a. If subsequent changes cause the facility's operations and emissions to revert to those authorized in the permit and the permittee resumes compliance with the terms and conditions of the permit, or

b. If the permittee obtains final approval of a significant modification to the permit to incorporate the change in the permit.

[45CSR§30-5.8.c.]

2.11.4. "Section 502(b)(10) changes" are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.
[45CSR§30-2.40]

2.12. Reasonably Anticipated Operating Scenarios

2.12.1. The following are terms and conditions for reasonably anticipated operating scenarios identified in this permit.

a. Contemporaneously with making a change from one operating scenario to another, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating and to document the change in reports submitted pursuant to the terms of this permit and 45CSR30.

b. The permit shield shall extend to all terms and conditions under each such operating scenario; and

c. The terms and conditions of each such alternative scenario shall meet all applicable requirements and the requirements of 45CSR30.

[45CSR§30-5.1.i.]

2.13. Duty to Comply

2.13.1. 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; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.
[45CSR§30-5.1.f.1.]

2.14. Inspection and Entry

2.14.1. 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;

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.

[45CSR§30-5.3.b.]

2.15. Schedule of Compliance

2.15.1. For sources subject to a compliance schedule, certified progress reports shall be submitted consistent with the applicable schedule of compliance set forth in this permit and 45CSR§30-4.3.h., but at least every six (6) months, and no greater than once a month, and shall include the following:

a. Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when such activities, milestones or compliance were achieved; and

b. An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measure adopted.

[45CSR§30-5.3.d.]

2.16. Need to Halt or Reduce Activity not a Defense

2.16.1. It shall not be a defense for a permittee in an enforcement action that it would 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.
[45CSR§30-5.1.f.2.]

2.17. Reserved

2.18. Federally-Enforceable Requirements

2.18.1. All terms and conditions in this permit, including any provisions designed to limit a source's potential to emit and excepting those provisions that are specifically designated in the permit as "State-enforceable only", are enforceable by the Secretary, USEPA, and citizens under the Clean Air Act.
[45CSR§30-5.2.a.]

2.18.2. Those provisions specifically designated in the permit as “State-enforceable only” shall become “Federally-enforceable” requirements upon SIP approval by the USEPA.

2.19. Duty to Provide Information

2.19.1. 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 modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records required 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.
[45CSR§30-5.1.f.5.]

2.20. Duty to Supplement and Correct Information

2.20.1. 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.
[45CSR§30-4.2.]

2.21. Permit Shield

2.21.1. Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance provided that such applicable requirements are included and are specifically identified in this permit or the Secretary has determined that other requirements specifically identified are not applicable to the source and this permit includes such a determination or a concise summary thereof.
[45CSR§30-5.6.a.]

2.21.2. Nothing in this permit shall alter or affect the following:

a. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance; or

b. The applicable requirements of the Code of West Virginia and Title IV of the Clean Air Act (Acid Deposition Control), consistent with § 408 (a) of the Clean Air Act.

c. The authority of the Administrator of U.S. EPA to require information under § 114 of the Clean Air Act or to issue emergency orders under § 303 of the Clean Air Act.

[45CSR§305.6.c.]

2.22. Credible Evidence

2.22.1. 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 defenses otherwise available to the permittee including but not limited to any challenge to the credible evidence rule in the context of any future proceeding.
[45CSR§30-5.3.e.3.B.]

2.23. Severability

2.23.1. The provisions of this permit are severable. If any provision of this permit, or the application of any provision of this permit to any circumstance is held invalid by a court of competent jurisdiction, the remaining permit terms and conditions or their application to other circumstances shall remain in full force and effect.
[45CSR§305.1.e.]

2.24. Property Rights

2.24.1. This permit does not convey any property rights of any sort or any exclusive privilege.
[45CSR§30-5.1.f.4]

2.25. Acid Deposition Control

2.25.1. Emissions shall not exceed any allowances that the source lawfully holds under Title IV of the Clean Air Act (Acid Deposition Control) or rules of the Secretary promulgated thereunder.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid deposition control program, provided that such increases do not require a permit revision under any other applicable requirement.

b. No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

c. Any such allowance shall be accounted for according to the procedures established in rules promulgated under Title IV of the Clean Air Act.

[45CSR§30-5.1.d.]

2.25.2. Where applicable requirements of the Clean Air Act are more stringent than any applicable requirement of regulations promulgated under Title IV of the Clean Air Act (Acid Deposition Control), both provisions shall be incorporated into the permit and shall be enforceable by the Secretary and U. S. EPA.
[45CSR§30-5.1.a.2.]

3.0 Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person 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 or allow 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.
[40 C.F.R. §61.145(b) and 45CSR34]

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. **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]

3.1.6. **Emission inventory.** The permittee is responsible for submitting, on an annual basis, an emission inventory in accordance with the submittal requirements of the Division of Air Quality.
[W.Va. Code § 22-5-4(a)(15)]

3.1.7. **Ozone-depleting substances.** For those facilities performing maintenance, service, repair or disposal of appliances, the permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 C.F.R. Part 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the prohibitions and required practices pursuant to 40 C.F.R. §§ 82.154 and 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 C.F.R. § 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 C.F.R. § 82.161.

[40 C.F.R. 82, Subpart F]

3.1.8. **Risk Management Plan.** Should this stationary source, as defined in 40 C.F.R. § 68.3, become subject to Part 68, then the owner or operator shall submit a risk management plan (RMP) by the date specified in 40 C.F.R. § 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 C.F.R. Part 70 or 71.
[40 C.F.R. 68]

3.1.9. **Fugitive Particulate Matter Control.** No person shall cause, suffer, allow, or permit any source of fugitive particulate matter to operate that is not equipped with a fugitive particulate matter control system. This system shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter. Sources of fugitive particulate matter associated with fuel burning units shall include, but not be limited to, the following:

a. Stockpiling of ash or fuel either in the open or in enclosures such as silos;

b. Transport of ash in vehicles or on conveying systems, to include spillage, tracking, or blowing of particulate matter from or by such vehicles or equipment; and

c. Ash or fuel handling systems and ash disposal areas.

d. Flue Gas Desulfurization (FGD) and Selective Catalytic Reduction (SCR) material handling systems.

[45CSR§2-5; 45CSR13, R13-2608, 4.1.18.]

3.1.10. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed within Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S, and emission unit Aux 1 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.
[45CSR13, R13-2608, 4.1.25. and 5.1.2; 45CSR§13-5.11.]

3.1.11. **40 C.F.R. Part 97, Subpart AAAAA – CSAPR NO_x Annual Trading Program.** The permittee shall comply with the standard requirements set forth in the attached Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements (see APPENDIX E).
[40 C.F.R. § 97.406; 45CSR43]

3.1.12. **40 C.F.R. Part 97, Subpart EEEEE – CSAPR NO_x Ozone Season Group 2 Trading Program.** The permittee shall comply with the standard requirements set forth in the attached Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements (see APPENDIX E).
[40 C.F.R. § 97.806; 45CSR43]

3.1.13. **40 C.F.R. Part 97, Subpart CCCCC – CSAPR SO_2 Group 1 Trading Program.** The permittee shall comply with the standard requirements set forth in the attached Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements (see APPENDIX E).
[40 C.F.R. § 97.606; 45CSR43]

3.2. Monitoring Requirements

3.2.1. 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 sourcespecific 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, if applicable, in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable.

b. The Secretary may on a sourcespecific 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 shall be revised in accordance with 45CSR§30-6.4 or 45CSR§30-6.5 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 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.

3. A statement of compliance or non-compliance with each permit or rule condition.

[WV Code §§ 2254(a)(15-16) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Monitoring information.** 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.

[45CSR§30-5.1.c.2.A.]
[45CSR13, R13-2608, 4.4.1.] (Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S)
[45CSR13, R13-2608, 5.4.1.] (Em. Unit ID: Aux 1)

3.4.2. **Retention of records.** The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of monitoring sample, measurement, report, application, or record creation date. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Where appropriate, records may be maintained in computerized form in lieu of the above records.
[45CSR§30-5.1.c.2.B.]

3.4.3. **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§30-5.1.c. State-Enforceable only.]

3.4.4. The permittee shall maintain records indicating the use of any dust suppressants or any other suitable dust control measures applied at the facility. The permittee shall also inspect all fugitive dust control systems weekly from May 1 through September 30 and monthly from October 1 through April 30 to ensure that they are operated as necessary and maintained in good working order. The permittee shall maintain records of all scheduled and non-scheduled maintenance and shall state any maintenance or corrective actions taken as a result of the weekly and/or monthly inspections, the times the fugitive dust control system(s) were inoperable and any corrective actions taken.
[45CSR§30-5.1.c.]

3.4.5. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed within Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S in Section 1.0 and control equipment for the Auxiliary Boiler (Aux 1), the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.
[45CSR13, R13-2608, 4.4.2. and 5.4.2.]

3.4.6. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed within Emission Groups 1S, 2S, 3S, 4S, 5S, 6S, 7S, 9S, and 11S in Section 1.0 and control equipment for the Auxiliary Boiler (Aux 1), 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.

[45CSR13, R13-2608, 4.4.3. and 5.4.3.]

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.
[45CSR§§30-4.4. *and* 5.1.c.3.D.]

3.5.2. A permittee may request confidential treatment for the submission of reporting required under 45CSR§30-5.1.c.3. pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.
[45CSR§30-5.1.c.3.E.]

3.5.3. Except for the electronic submittal of the annual compliance certification and semi-annual monitoring reports to the DAQ and USEPA as required in 3.5.5 and 3.5.6 below, 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 or by private carrier with postage prepaid to the address(es), or submitted in electronic format by e-mail as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ:	**US EPA:**
Director WVDEP Division of Air Quality 601 57th Street SE Charleston, WV 25304	Section Chief U. S. Environmental Protection Agency, Region III Enforcement and Compliance Assurance Division Air, RCRA and Toxics Branch (3ED21) Four Penn Center 1600 John F. Kennedy Boulevard Philadelphia, PA 19103-2852

DAQ Compliance and Enforcement[1]:
DEPAirQualityReports@wv.gov

[1]For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status reports, Initial Notifications, etc.

3.5.4. **Fees.** The permittee shall pay fees on an annual basis in accordance with 45CSR§30-8.
[45CSR§30-8.]

3.5.5. **Compliance certification.** The permittee shall certify compliance with the conditions of this permit on the forms provided by the DAQ. In addition to the annual compliance certification, the permittee may be required to submit certifications more frequently under an applicable requirement of this permit. The annual certification shall be submitted to the DAQ and USEPA on or before March 15 of each year, and shall certify compliance for the period ending December 31. The permittee shall maintain a copy of the certification on site for five (5) years from submittal of the certification. The annual certification shall be submitted in electronic format by e-mail to the following addresses:

DAQ:	**US EPA:**
DEPAirQualityReports@wv.gov	R3_APD_Permits@epa.gov

[45CSR§30-5.3.e.]

3.5.6. **Semi-annual monitoring reports.** The permittee shall submit reports of any required monitoring on or before September 15 for the reporting period January 1 to June 30 and on or before March 15 for the reporting period July 1 to December 31. All instances of deviation from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with 45CSR§30-4.4. The semi-annual monitoring reports shall be submitted in electronic format by e-mail to the following address:

DAQ:
DEPAirQualityReports@wv.gov

[45CSR§30-5.1.c.3.A.]

3.5.7. **Reserved.**

3.5.8. **Deviations.**

a. In addition to monitoring reports required by this permit, the permittee shall promptly submit supplemental reports and notices in accordance with the following:

1. Reserved.

2. Any deviation that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to the Secretary immediately by telephone or email. A written report of such deviation, which shall include the probable cause of such deviation, and any corrective actions or preventative measures taken, shall be submitted by the responsible official within ten (10) days of the deviation.

3. Deviations for which more frequent reporting is required under this permit shall be reported on the more frequent basis.

4. All reports of deviations shall identify the probable cause of the deviation and any corrective actions or preventative measures taken.

[45CSR§30-5.1.c.3.C.]

b. The permittee shall, in the reporting of deviations from permit requirements, including those attributable to upset conditions as defined in this permit, report the probable cause of such deviations and any corrective actions or preventive measures taken in accordance with any rules of the Secretary. **[45CSR§30-5.1.c.3.B.]**

3.5.9. **New applicable requirements.** If any applicable requirement is promulgated during the term of this permit, the permittee will meet such requirements on a timely basis, or in accordance with a more detailed schedule if required by the applicable requirement.
[45CSR§30-4.3.h.1.B.]

3.6. Compliance Plan

3.6.1. There is no compliance plan since a responsible official certified compliance with all applicable requirements in the Title V renewal application.

3.7. Permit Shield

3.7.1. The permittee is hereby granted a permit shield in accordance with 45CSR§30-5.6. The permit shield applies provided the permittee operates in accordance with the information contained within this permit.

3.7.2. The following requirements specifically identified are not applicable to the source based on the determinations set forth below. The permit shield shall apply to the following requirements provided the conditions of the determinations are met.

a. **45CSR5 – *To Prevent and Control Air Pollution from the Operation of Coal Preparation Plants, Coal Handling Operations and Coal Refuse Disposal Areas***. Since the facility is subject to 45CSR2, according to 45CSR§5-2.4.b. the facility is not included in the definition of a "Coal Preparation Plant". Therefore, 45CSR5 does not apply to the facility, and particularly to its coal crushing operations and associated coal handling.

b. **45CSR7 – *To Prevent and Control Particulate Matter Air Pollution from Manufacturing Processes and Associated Operations.*** Since the facility is subject to 45CSR2, 45CSR§7-10.1. provides an exemption from 45CSR7.

c. **45CSR17 – *To Prevent and Control Particulate Matter Air Pollution from Material Handling, Preparation, Storage and Other Sources of Fugitive Particulate Matter.*** The facility is characterized by the handling and storage of materials that have the potential to produce fugitive particulate if not properly controlled. However, since the facility is subject to 45CSR2, it is not subject to this rule in accordance with the exemption granted in 45CSR§17-6.1.

d. **40 C.F.R. 60 Subpart D – *Standards of Performance for Fossil-fuel-fired Steam Generators for which Construction is Commenced after August 17, 1971.*** The fossil-fuel-fired steam generators potentially affected by this rule have not commenced construction or modification after August 17, 1971. Therefore, the units do not meet the applicability criteria under §60.40(c), and hence the NSPS does not apply.

e. **40 C.F.R. 60 Subpart Da – *Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978.*** The electric utility steam generating units (i.e., Unit 1 and Unit 2) potentially affected by this rule have not commenced construction or modification after September 18, 1978. Therefore, the units do not meet the applicability criteria under §60.40Da(a)(2), and hence the NSPS does not apply to Unit 1 and Unit 2. The auxiliary boiler (Aux 1) was not constructed or reconstructed "for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale." As such, Aux 1 does not meet the definition of an *Electric utility steam-generating unit* in §60.41Da, and therefore, does not meet the applicability criteria of §60.40Da(a). Consequently, NSPS Subpart Da does not apply to Aux 1.

f. **40 C.F.R. 60 Subpart K - *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R. §60.111(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after June 11, 1973 and prior to May 19, 1978. Therefore, the tanks do not meet the applicability criteria under §60.110, and hence the NSPS does not apply.

g. **40 C.F.R. 60 Subpart Ka - *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.*** The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 C.F.R. §60.111a(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction or modification was commenced after May 18, 1978 and prior to July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110a(a), and hence the NSPS does not apply.

h. **40 C.F.R. 60 Subpart Kb - *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.*** Storage vessels potentially affected by this rule are exempted because they contain liquids with a maximum true vapor pressure of less than 3.5 kPa, have a storage capacity of less than 75 cubic meters, or have not commenced construction, reconstruction or modification after July 23, 1984. Therefore, the tanks do not meet the applicability criteria under §60.110b, and hence the NSPS does not apply.

i. **40 C.F.R. 60 Subpart Y – *Standards of Performance for Coal Preparation Plants.*** The coal handling equipment potentially affected by this rule has not been constructed or modified after October 24, 1974. Therefore, the equipment does not meet the applicability criteria set forth in 40 C.F.R. §60.250(b), and hence this NSPS does not apply.

j. **40 C.F.R. 63 Subpart Q – *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers.*** This facility does not include *industrial process cooling towers* that have operated with chromium-based water treatment chemicals. Therefore, the facility does not meet the applicability criteria set forth in §63.400(a), and hence this MACT does not apply to the facility.

4.0 Main Boilers [Emission Unit IDs *Unit 1* and *Unit 2* – Emission Point IDs *1E* and *2E*]

4.0.1. **Emergency Operating Scenarios**

a. In the event of an unavoidable shortage of fuel having characteristics or specifications necessary to comply with the visible emission requirements or any emergency situation or condition creating a threat to public safety or welfare, the Secretary may grant an exemption to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during that period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the weight emission requirements will not be exceeded during the exemption period.
[45CSR§2-10.1.]

b. Due to unavoidable malfunction of equipment or inadvertent fuel shortages, SO_2 emissions from the main boilers exceeding those provided for in 45CSR§§10-3.1.b. and 3.1.e., respectively, may be permitted by the Secretary for periods not to exceed ten (10) days upon specific application to the Secretary. Such application shall be made within twenty-four (24) hours of the equipment malfunction or fuel shortage. In cases of major equipment failure or extended shortages of conforming fuels, additional time periods may be granted by the Secretary, provided a corrective program has been submitted by the owner or operator and approved by the Secretary.
[45CSR§10-9.1.]

4.0.2. **Thermal Decomposition of Boiler Cleaning Solutions.** The thermal decomposition of boiler cleaning solutions is permitted upon notification to the Secretary, provided that records are maintained which show that the solutions are non-hazardous materials and that the combustion of such solutions does not produce hazardous compounds or emissions. Such records shall be kept on site for a period of no less than five (5) years and shall be made available, in a suitable form for inspection, to the Secretary upon request. See Appendix C.
[WVDAQ Letter dated September 3, 2002 addressed to Mr. Greg Wooten and signed by Jesse D. Adkins - State-Enforceable only]

4.0.3. **Combustion of Demineralizer Resins.** The combustion of demineralizer resins is permitted in accordance with the WVDAQ letter dated January 21, 2004 addressed to Mr. Frank Blake and signed by Jesse D. Adkins and subject to the DAQ notification requirements as outlined in the document titled "American Electric Power Demineralizer Resin Burn Notification Procedure." Records pertaining to the combustion of demineralizer resins shall be kept in accordance with 3.3.2. and shall be made available, in a suitable form for inspection, to the Secretary upon request. See Appendix D.
[WVDAQ Letter dated January 21, 2004 addressed to Mr. Frank Blake and signed by Jesse D. Adkins - State-Enforceable only; 45CSR§30-5.1.c.]

4.1. Limitations and Standards

4.1.1. Any fuel burning unit(s) including associated air pollution control equipment, shall at all times, including periods of start-up, shutdowns, and malfunctions, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions.
[45CSR§2-9.2.]

4.1.2. Visible Emissions from Unit 1 & 2 stacks shall not exceed ten (10) percent opacity based on a six minute block average.
[45CSR§2-3.1.]

4.1.3. The visible emission standards (condition 4.1.2.) shall apply at all times except in periods of start-ups, shutdowns and malfunctions.
[45CSR§2-9.1.]

4.1.4. a. Particulate matter emissions from Unit 1 & 2 stacks shall not exceed 702 lb/hr. The averaging time shall be the arithmetic average of three (3) complete sampling runs consisting of a minimum total sampling time of two (2) hours per run.
[45CSR§2-4.1.a.; 45CSR2-Appendix §§ 4.1.b. & 4.1.c.]

b. **Filterable Particulate Matter (PM) Emission Limitation for 40 C.F.R. 63 Subpart UUUUU.** If your EGU is in the coal-fired unit not low rank virgin coal subcategory, for filterable particulate matter (PM), you must meet the emission limit 0.030 lb/MMBtu or 0.30 lb/MWh, by collecting a minimum of 1 dscm per run according to applicable test methods in Table 5 to Subpart UUUUU. For LEE emissions testing for total PM, the required minimum sampling volume must be increased nominally by a factor of two.
[40 C.F.R. §63.9991(a)(1), Table 2, Item #1.a.; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.5. a. Sulfur dioxide emissions from Unit 1 and Unit 2 stacks (Em. Pt. IDs: 1E, 2E) shall not exceed a heat input weighted average of 1.2 lb/mmBtu SO_2 on a 3-hour block average basis, with SO_2 mass emissions not to exceed an average of 20,485.2 lb SO_2/hr on a 3-hour block average basis. *Compliance with this limitation will assure compliance with the 45CSR10 limitation of 7.5 lb/mmBtu.*
[45CSR§30-12.7.; 45CSR§§10-3.1., and 3.1.b.]

b. **Sulfur Dioxide (SO_2) Emission Limitation for 40 C.F.R. 63 Subpart UUUUU.** If your EGU is in the coal-fired unit not low rank virgin coal subcategory, for sulfur dioxide (SO_2), you must meet the emission limit 0.20 lb/MMBtu, using SO_2 CEMS according to applicable methods in Table 5 and procedures in Table 7 to 40 C.F.R. 63 Subpart UUUUU.

You may use the alternate SO_2 limit in Table 2 to 40 C.F.R. 63 Subpart UUUUU only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and 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 40 C.F.R. §63.10000(b) (permit condition 4.1.12.).

[40 C.F.R. §63.9991(a)(1), Table 2, Item #1.b.; 40 C.F.R. §63.10000(a); 40 C.F.R. §§63.9991(c)(1) and (2); 45CSR34]

4.1.6. Compliance with the allowable sulfur dioxide emission limitations from the Unit 1 & 2 boilers in condition 4.1.5.a. shall be based on a continuous twenty-four (24) hour averaging time. Emissions shall not be allowed to exceed the weight emissions standards for sulfur dioxide as set forth in 45CSR10, except during one (1) continuous twenty-four (24) hour period in each calendar month. During this one (1) continuous twenty-four hour period, emissions shall not be allowed to exceed such weight emission standards by more than ten percent (10%) without causing a violation of 45CSR10. A continuous twenty-four (24) hour period is defined as one (1) calendar day.

[45CSR§10-3.8.]

4.1.7. **Dry Sorbent Injection.** The permittee shall operate the SO_3 dry-sorbent injection control system consistent with the technological capabilities and limitations of the system and with good operation and maintenance practices whenever *Unit 1* or *Unit 2* (or both) is operating, except during periods of startup, shut-down, malfunction, and maintenance.
[45CSR§30-12.7., State-enforceable only]

4.1.8. **Mercury (Hg) Emission Limitation for 40 C.F.R. 63 Subpart UUUUU.** If your EGU is in the coal-fired unit not low rank virgin coal subcategory, for mercury (Hg), you must meet the emission limit 1.2 lb/TBtu, or 0.013 lb/GWh using either of the following:

(1) LEE testing for 30 days per Table 2 to Subpart UUUUU using applicable methods in Table 5 to Subpart UUUUU, or

(2) Hg CEMS or sorbent trap monitoring system only, using applicable methods in Table 5 to Subpart UUUUU.

[40 C.F.R. §63.9991(a)(1), Table 2, Item #1.c.; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.9. **Tune-up Work Practice Standard for 40 C.F.R. 63 Subpart UUUUU**. If your EGU is an existing EGU, you must conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in 40 C.F.R. §63.10021(e).

Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (1) through (9) of this condition. 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. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

(1) 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;

(2) 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;

(3) 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;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) 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;

(6) 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;

(7) 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 continual values before and after each optimization adjustment made by the system.

(8) You must maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (1) through (9) of 40 C.F.R. §§63.10021(e) (permit condition 4.1.9.) including:

(i) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period.

(9) Report the dates of the initial and subsequent tune-ups in hard copy, as specified in §63.10031(f)(5), through June 30, 2020. On or after July 1, 2020, report the date of all tune-ups electronically, in accordance with §63.10031(f). The tune-up report date is the date when tune-up requirements in paragraphs (6) and (7) of this condition are completed.

[40 C.F.R. §63.9991(a)(1), Table 3, Item #1; 40 C.F.R. §§63.10021(e)(1) through (9); 40 C.F.R. §63.10021(a), Table 7, Item #5; 40 C.F.R. §63.10000(e); 40 C.F.R. §63.10006(i)(1); 45CSR34]

4.1.10. **Startup Work Practice Standard for 40 C.F.R. 63 Subpart UUUUU.**

a. (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 §§63.10021(h) and (i) (permit conditions 4.1.14. and 4.5.10.a.(1)).

c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.

d. You must collect monitoring data during startup periods, as specified in §63.10020(a) (permit conditions 4.2.13., 4.2.14., and 4.2.15.). You must keep records during startup periods, as provided in §§63.10032 and 63.10021(h) (permit conditions 4.4.6. through 4.4.13., and 4.1.14.). You must provide reports concerning activities and startup periods, as specified in §§63.10021(i) (permit condition 4.5.10.a.(1)), and 63.10031 (permit condition 4.5.10.).

[40 C.F.R. §63.9991(a)(1), Table 3, Items 3.a.(1), 3.c., 3.d.; 40 C.F.R. §63.10021(a), Table 7, Item #6; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.11. **Shutdown Work Practice Standard for 40 C.F.R. 63 Subpart UUUUU.** 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 for those pollutants for which a CMS is used.

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 possible, taking into account considerations such as not compromising boiler or control device integrity.

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 §§63.10021(i), and 63.10031.

[40 C.F.R. §63.9991(a)(1), Table 3, Item #4; 40 C.F.R. §63.10021(a), Table 7, Item #7; 40 C.F.R. §63.10000(a); 45CSR34]

4.1.12. At all times you must operate and maintain any affected source, 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 EPA Administrator 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 C.F.R. §63.10000(b); 45CSR34]

4.1.13. Fuel Requirements for startup and shutdown.

(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

[40 C.F.R. §63.10011(f); 45CSR34]

4.1.14. You must follow the startup or shutdown requirements as given in Table 3 to 40 C.F.R. 63 Subpart UUUUU for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in §63.10007(f) (permit condition 4.2.16.), 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 (permit conditions 4.5.10., 4.5.11., 4.5.12., and 4.5.13.).

[40 C.F.R. §63.10021(h); 45CSR34]

4.1.15. **Selective Catalytic Reactors and Flue Gas Desulfurization**.

(1) On and after January 1, 2009, install and continuously operate Selective Catalytic reactors (SCRs) on Mitchell Units 1 and 2.

(2) On and after December 31, 2007, install and continuously operate Flue Gas Desulfurization (FGD) on Mitchell Units 1 and 2.

(3) Pursuant to the consent decree, "continuously operate" means that when the SCR and/or FGD is used at a unit, except during a "malfunction," the FGD and/or SCR shall be operated at all times the unit is in operation, consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices for the control equipment and the unit so as to minimize emissions to the greatest extent practicable.

(4) Pursuant to the consent decree, a "malfunction" means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(5) On and after December 31, 2012, install, calibrate, operate, and maintain PM CEMS on Mitchell Unit 2, and maintain in an electronic database the hourly average emission values in lbs/mmBtu. The permittee shall use reasonable efforts to keep the PM CEMS running and producing data whenever Unit 2 is operating. Data from the PM CEMS shall be used, at a minimum, to monitor progress in reducing PM emissions, but stack testing according to reference methods approved by the Administrator shall be used to determine compliance with any PM emission rate applicable to Unit 2.

[45CSR§30-12.7]

4.2. Monitoring Requirements

4.2.1. Compliance with the visible emission requirements for emission points *1E* and *2E* shall be determined as outlined in section I.A.2. of the DAQ approved "45CSR2 Monitoring Plan" attached in Appendix A of this permit.
[45CSR§§2-3.2., 8.1.a & 8.2., 45CSR§2A-6]

4.2.2. The owner or operator shall install, calibrate, certify, operate, and maintain continuous monitoring systems that measure opacity and all SO_2, and NO_x, emissions from emission points *1E* and *2E* as specified in 40 C.F.R. Part 75 and measure CO_2 emissions from emission points *1E* and *2E* as specified in 40 C.F.R. Part 75. Refer to permit condition 4.1.5.b. for the 40 C.F.R. 63 Subpart UUUUU SO_2 alternate limit for acid gases, and corresponding monitoring requirements in conditions 4.2.18. through 4.2.21.
[45CSR33; 40 C.F.R. §75.10; 40 C.F.R. §§ 64.3(b)(1) and 64.3(b)(4)(ii); 45CSR§30-5.1.c.]

4.2.3. Compliance with the operating and fuel usage requirements for Units 1 & 2 shall be demonstrated as outlined in section I.A.3. of the DAQ approved "45CSR2 Monitoring Plan" attached in Appendix A of this permit.
[45CSR§§2-8.3.c., 8.4.a. & 8.4.a.1.]

4.2.4. The owner or operator shall implement a Compliance Assurance Monitoring (CAM) program in accordance with the following:

(a) The permittee shall monitor and maintain 6-minute opacity averages measured by a continuous opacity monitoring system, operated and maintained pursuant to 40 C.F.R. Part 75, including the minimum data requirements, in order to determine 3-hour block average opacity values. The permittee may also use COMS that satisfy Section 51.214 and appendix P of Part 51, or Section 60.13 and appendix B of Part 60, to satisfy the general design criteria under 40 C.F.R. §§64.3(a) and (b).
[45CSR§30-5.1.c. and 40 C.F.R. § 64.6(c)(1)(i) and (ii)]

(b) The COM QA/QC procedures shall be equivalent to the applicable requirements of 40 C.F.R. Part 75. The permittee may also use COMS that satisfy Section 51.214 and appendix P of Part 51, or Section 60.13 and appendix B of Part 60, to satisfy the general design criteria under 40 C.F.R. §§64.3(a) and (b).
[40 C.F.R. §75.21 and 40 C.F.R. § 64.6(c)(iii)]

(c) The 6-minute opacity averages from permit condition 4.2.4.(a) shall be used to calculate 3-hour block average opacity values. Data recorded during monitoring malfunctions, associated repairs and QA/QC activities shall not be used for calculating the 3-hour averages. All other available qualified data consisting of 6-minute opacity averages will be used to calculate a 3-hour average. Data availability shall be at least of 50% of the operating time in the 3-hour block to satisfy the data requirements to calculate the 3-hour average opacity. However, the number of invalid 3-hour blocks shall not exceed 15% of the total 3-hour blocks during unit operation for a quarterly reporting period.

An excursion of the indicator range shall be defined as two consecutive 3-hour block average opacity values that exceed 10%.

[45CSR§30-5.1.c.; 40 C.F.R. §§ 64.6(c)(2) and (4) and 40 C.F.R. § 64.7(c)]

4.2.5. **Proper Maintenance** – At all times, the permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[40 C.F.R. § 64.7(b); 45CSR§30-5.1.c.]

4.2.6. **Response to Excursions or Exceedances**

(a) Upon detecting an excursion or exceedance, the permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable

(b) Determination of whether the permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 C.F.R. § 64.7(d); 45CSR§30-5.1.c.]

4.2.7. **Documentation of Need for Improved Monitoring** – After approval of monitoring under 40 C.F.R. Part 64, if the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the Director and, if necessary, submit a proposed modification to the permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[40 C.F.R. § 64.7(e); 45CSR§30-5.1.c.]

4.2.8. **Quality Improvement Plan (QIP)**

(1) Based on the results of a determination made under permit condition 4.2.6.(b) or 4.2.8.(2), the Administrator or the Director may require the permittee to develop and implement a QIP. If a QIP is required, then it shall be developed, implemented, and modified as required according to 40 C.F.R. §§ 64.8(b) through (e). Refer to permit condition 4.5.6.(b)(iii) for the reporting required when a QIP is implemented.

(2) If five (5) percent or greater of the three (3) hour average COMS opacity values, determined in accordance with 4.2.4.(c) of this permit, indicate excursions of the 10% opacity threshold during a calendar quarter, the permittee shall develop and implement a QIP. The Director may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to permit condition 3.2.1.

[40 C.F.R. §§ 64.8, and 64.7(d); 45CSR§30-5.1.c.]

4.2.9. **Continued Operation** – Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of 40 C.F.R. Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[40 C.F.R. § 64.7(c); 45CSR§30-5.1.c.]

4.2.10. The permittee shall perform daily monitoring and recordkeeping of the total daily dry sorbent usage rate (pounds /tons per day) and startups, shutdowns, malfunctions, and maintenance associated with the dry sorbent injection system.
[45CSR§30-5.1.c., State-enforceable only]

4.2.11. If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values in §63.10007(f) are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of 40 C.F.R. 63 Subpart UUUUU, these default values are not considered to be substitute data.

[40 C.F.R. §63.10007(f); 45CSR34] (*SO_2 CEMS; Hg sorbent trap monitoring system*)

4.2.12. *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 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. You 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.

If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

SO_2 CEMS Requirements for 40 C.F.R. 63 Subpart UUUUU.

(1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.
(2) 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 this chapter, with the following addition: You 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.
(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 30 boiler operating day period.
(4) 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 §63.10042) the default gross output and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO_2 emission rate for any of these hours.

If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You 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 the subpart, 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 this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

[40 C.F.R. §§63.10010(a)(1), (b), (c), (f), and (g); 40 C.F.R. §63.10021(a), Table 7, Item #1; 45CSR34]

4.2.13. You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.
[40 C.F.R. §§63.10020(b) and (a); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.2.14. You may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 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. You 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 C.F.R. §§63.10020(c) and (a); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.2.15. 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 C.F.R. §§63.10020(d) and (a); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.2.16. Except as otherwise provided in §63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in §63.10021(b) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.
[40 C.F.R. §63.10021(b); 45CSR34] (*SO_2 CEMS and Hg Sorbent Trap Monitoring System*)

4.3. Testing Requirements

4.3.1. The owner or operator shall conduct, or have conducted, tests to determine the compliance of Unit 1 & Unit 2 with the particulate matter mass emission limitations. Such tests shall be conducted in accordance with the appropriate method set forth in 45CSR2 Appendix - Compliance Test Procedures for 45CSR2 or other equivalent EPA approved method approved by the Secretary. Such tests shall be conducted in accordance with the schedule set forth in the following table. The next testing shall be performed no later than December 13, 2021.

Test	Test Results	Retesting Frequency
Annual	after three successive tests indicate mass emission rates $\leq$50% of weight emission standard	Once/3 years [1]
Annual	after two successive tests indicate mass emission rates <80 % of weight emission standard	Once/2 years [2]
Annual	any test indicates a mass emission rate $\geq$80% of weight emission standard	Annual [3]
Once/2 years	after two successive tests indicate mass emission rates $\leq$50% of weight emission standard	Once/3 years
Once/2 years	any test indicates a mass emission rate <80 % of weight emission standard	Once/2 years
Once/2 years	any test indicates a mass emission rate $\geq$80% of weight emission standard	Annual
Once/3 years	any test indicates a mass emission rate $\leq$50% of weight emission standard	Once/3 years
Once/3 years	any test indicates mass emission rates between 50% and 80 % of weight emission standard	Once/2 years
Once/3 years	any test indicates a mass emission rate $\geq$80% of weight emission standard	Annual

[1] Once/3 years is Cycle '3' and means that testing shall be performed within thirty-six (36) months from the date of the previous test, but no earlier than eighteen (18) months from the date of the previous test (see 45CSR§2A-2.6.c.).

[2] Once/2 years is Cycle '2' and means that testing shall be performed within twenty-four (24) months from the date of the previous test, but no earlier than twelve (12) months from the date of the previous test (see 45CSR§2A-2.6.b.).

[3] Annual is Cycle '1' and means that testing shall be performed within twelve (12) months from the date of the previous test, but no earlier than six (6) months from the date of the previous test (see 45CSR§2A-2.6.a.).

[45CSR§2-8.1., 45CSR§2A-5.2.]

4.3.2. Data collected during future periodic 45CSR2 mass emissions tests (under permit condition 4.3.1.) will be used to supplement the existing data set in order to verify the continuing appropriateness of the 10% indicator range value.
[45CSR§30-5.1.c. and 40 C.F.R. § 64.6(b)]

4.3.3. *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).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in §63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in §63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(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- (or 90-) boiler operating day test period. You may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. 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.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from §75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly gross output data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m3 (dry basis), for the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and gross output for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in §63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(1) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^{-6} to convert it to TBtu/hr; or

(2) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^{-3} to convert it to GW; or

(3) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

[40 C.F.R. §63.10005(h); 45CSR34]

4.3.4. For affected units meeting the LEE requirements of §63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and §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:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1).

[40 C.F.R. §63.10006(b); 45CSR34]

4.3.5. *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, measured from the test's end date, must separate performance tests conducted every quarter;

(ii) For annual testing:

(A) At least 320 calendar days, measured from the test's end date, must separate performance tests,

(B) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests,

(C) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and

(iii) At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years.

(2) For units demonstrating compliance through quarterly emission testing, 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 168 or more boiler operating hours occur 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.

[40 C.F.R. §63.10006(f); 45CSR34]

4.3.6. If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in §63.10006(b) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.
[40 C.F.R. §63.10006(h); 45CSR34]

4.3.7. Except as otherwise provided in 40 C.F.R. §63.10007, you must conduct all required performance tests according to 40 C.F.R. §§63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in 40 C.F.R. §63.7(c).
[40 C.F.R. §63.10007(a); 45CSR34]

4.3.8. If you use SO_2 CEMS to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 to this subpart), except as otherwise provided in §63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).
[40 C.F.R. §63.10007(a)(1); 45CSR34]

4.3.9. If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.
[40 C.F.R. §63.10007(a)(2); 45CSR34] (*Particulate Matter*)

4.3.10. You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to 40 C.F.R. 63 Subpart UUUUU.
[40 C.F.R. §63.10007(b); 45CSR34]

4.3.11. Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.
[40 C.F.R. §63.10007(d); 45CSR34] (*Particulate Matter*)

4.3.12. To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 to 40 C.F.R. 63 Subpart UUUUU, proceed as in 40 C.F.R. §§63.10007(e)(1) through (3). If you use quarterly performance testing for coal-fired EGUs to measure compliance with PM emissions limit in Table 2 to Subpart UUUUU, you demonstrate continuous compliance by calculating the results of the testing in units of the applicable emissions standard.
[40 C.F.R. §63.10007(e); 40 C.F.R. §63.10021(a), Table 7, Item #4; 45CSR34]

4.3.13. Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007.
[40 C.F.R. §63.10007(g); 45CSR34]

4.3.14. For candidate LEE units, use the results of the performance testing described in §63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 2 to this subpart and to determine whether the unit qualifies for LEE status.
[40 C.F.R. §63.10011(d); 45CSR34]

4.3.15. If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 to 40 C.F.R. 63 Subpart UUUUU, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year; and

(2) Must conduct the performance test as defined in Table 5 to 40 C.F.R. 63 Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard.

[40 C.F.R. §§63.10021(d), (d)(1), and (d)(2); 45CSR34]

4.3.16. *Notification of performance test*. When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin. *Compliance with this requirement ensures compliance with 40 C.F.R. §§63.7(b) and 63.9(e).*
[40 C.F.R. §63.10030(d) and (a); 40 C.F.R. §§63.7(b) and 63.9(e); 45CSR34]

4.3.17. If your coal-fired EGU does not qualify as a LEE for filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.
[40 C.F.R. §63.10000(c)(1)(iv); 45CSR34]

4.4. Recordkeeping Requirements

4.4.1. Records of monitored data established in the monitoring plan (see Appendix A) shall be maintained on site and shall be made available to the Secretary or his duly authorized representative upon request.
[45CSR§2-8.3.a.]

4.4.2. Records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit, shall be maintained on-site in a manner to be established by the Secretary and made available to the Secretary or his duly authorized representative upon request.
[45CSR§2-8.3.c.]

4.4.3. Records of the block 3-hour COMS opacity averages and corrective actions taken during excursions of the CAM plan indicator range shall be maintained on site and shall be made available to the Director or his duly authorized representative upon request. COMS performance data will be maintained in accordance with 40 C.F.R. Part 75 recordkeeping requirements.
[45CSR§30-5.1.c. and 40 C.F.R. §64.9(b)]

4.4.4. **General recordkeeping requirements for 40 C.F.R. Part 64 (CAM).** The permittee shall comply with the recordkeeping requirements specified in permit conditions 3.3.1. and 3.3.2. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 C.F.R. §64.8 (condition 4.2.8.) and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 C.F.R. Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).
[40 C.F.R. § 64.9(b); 45CSR§30-5.1.c.]

4.4.5. **Format and Retention of Records for 40 C.F.R. 63 Subpart UUUUU**

(a) Your records must be in a form suitable and readily available for expeditious review, according to 40 C.F.R. §63.10(b)(1).

(b) As specified in 40 C.F.R. §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

[40 C.F.R. §§63.10033(a), (b), and (c); 45CSR34]

4.4.6. You must keep records according to paragraphs (1) and (2) of this condition. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to 40 C.F.R. 63 Subpart UUUUU.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

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

[40 C.F.R. §63.10032(a); 45CSR34]

4.4.7. For each CEMS, you must keep records according to paragraphs (1) through (4) of this condition.

(1) Records described in §63.10(b)(2)(vi) through (xi).

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

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

(4) 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 C.F.R. §63.10032(b); 45CSR34]

4.4.8. You must keep the records required in Table 7 to 40 C.F.R. 63 Subpart UUUUU to show continuous compliance with each emission limit and operating limit that applies to you (conditions 4.1.4.b., 4.1.5.b., 4.1.8., and 4.1.9.).
[40 C.F.R. §63.10032(c), Table 7, Items #1, #4, #5, #6, #7; 45CSR34]

4.4.9. For each EGU subject to an emission limit, you must also keep the records in paragraphs (1) through (3) of this condition.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under §63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, 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 C.F.R. §63.10032(d); 45CSR34]

4.4.10. 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.

[40 C.F.R. §§63.10032(f) and (f)(1); 45CSR34]

4.4.11. You 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 C.F.R. §63.10032(g); 45CSR34]

4.4.12. You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (permit condition 4.1.10.), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 C.F.R. §63.10032(h); 45CSR34]

4.4.13. You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.
[40 C.F.R. §63.10032(i); 45CSR34]

4.5. Reporting Requirements

4.5.1. The designated representative shall electronically report SO_2, NO_x, and CO_2 emissions data and information as specified in 40 C.F.R. § 75.64 to the Administrator of USEPA, quarterly. Each electronic report must be submitted within thirty (30) days following the end of each calendar quarter.
[45CSR33; 40 C.F.R. §75.64]

4.5.2. A periodic exception report shall be submitted to the Secretary, in a manner and at a frequency to be established by the Secretary. Compliance with this periodic exception reporting requirement shall be demonstrated as outlined in sections I.A.4. and II.A.4. of the DAQ approved “45CSR2 and 45CSR10 Monitoring Plan” attached in Appendix A of this permit.
[45CSR§2-8.3.b.]

4.5.3. Excess opacity periods resulting from any malfunction of Unit 1 or Unit 2, or their air pollution control equipment, meeting the following conditions, may be reported on a quarterly basis unless otherwise required by the Secretary:

a. The excess opacity period does not exceed thirty (30) minutes within any twenty-four (24) hour period; and

b. Excess opacity does not exceed forty percent (40%).

[45CSR§2-9.3.a.]

4.5.4. Except as provided in permit condition 4.5.3. above, the owner or operator shall report to the Secretary by telephone, telefax, or e-mail any malfunction of Unit 1 or Unit 2, or their associated air pollution control equipment, which results in any excess particulate matter or excess opacity, by the end of the next business day after becoming aware of such condition. The owner or operator shall file a certified written report concerning the malfunction with the Secretary within thirty (30) days providing the following information:

a. A detailed explanation of the factors involved or causes of the malfunction;

b. The date, and time of duration (with starting and ending times) of the period of excess emissions;

c. An estimate of the mass of excess emissions discharged during the malfunction period;

d. The maximum opacity measured or observed during the malfunction;

e. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction; and

f. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.b.]

4.5.5. Unit 1 & Unit 2 are Phase II Acid Rain affected units under 45CSR33, as defined by 40 C.F.R § 72.6, and as such are required to meet the requirements of 40 C.F.R. Parts 72, 73, 74, 75, 76, 77 and 78. These requirements include, but are not limited to:

a. Hold an Acid Rain permit;

b. Hold allowances, as of the allowance transfer deadline, in the unit's compliance sub-account of not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit;

c. Comply with the applicable Acid Rain emissions for sulfur dioxide;

d. Comply with the applicable Acid Rain emissions for nitrogen oxides;

e. Comply with the monitoring requirements of 40 C.F.R. Part 75 and section 407 of the Clean Air Act of 1990 and regulations implementing section 407 of the Act;

f. Submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 C.F.R. Part 72, Subpart I and 40 C.F.R. Part 75.

[45CSR33; 40 C.F.R. Parts 72, 73, 74, 75, 76, 77, 78]

4.5.6. **General reporting requirements for 40 C.F.R. Part 64 (CAM)**

(a) On and after the date specified in 40 C.F.R. §64.7(a) by which the permittee must use monitoring that meets the requirements of 40 C.F.R. 64, the permittee shall submit monitoring reports to the DAQ in accordance with permit condition 3.4.6.

(b) A report for monitoring under 40 C.F.R. 64 shall include, at a minimum, the information required under permit condition 3.4.8. and the following information, as applicable:

(i) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(ii) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(iii) A description of the actions taken to implement a QIP during the reporting period as specified in 40 C.F.R. §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 C.F.R. § 64.9(a); 45CSR§30-5.1.c.]

4.5.7. You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.
[40 C.F.R. §63.10021(f); 45CSR34]

4.5.8. You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 2 and 3 to 40 C.F.R. 63 Subpart UUUUU or failed to conduct a required tune-up (permit conditions 4.1.4.b., 4.1.5.b., 4.1.8., and 4.1.9.). These instances are deviations from the requirements of this subpart. These deviations must be reported according to §63.10031.
[40 C.F.R. §63.10021(g); 45CSR34]

4.5.9. You must submit all of the notifications in 40 C.F.R. §63.7(c), and §63.8(e), by the dates specified.
[40 C.F.R. §63.10030(a); 45CSR34]

4.5.10. You must submit a Compliance report for 40 C.F.R. 63 Subpart UUUUU containing:

a. Information required in 40 C.F.R. §§63.10031(c)(1) through (4) and (6) through (9):

(1) The information required by the summary report located in 40 C.F.R. §63.10(e)(3)(vi).

(2) 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 your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

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

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in §§63.10021(e)(6) and (7) (permit conditions 4.1.9.(6) and (7)) were completed.

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, 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 §63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

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 40 C.F.R. 63 Subpart UUUUU 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 40 C.F.R. §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 40 C.F.R. §63.10031(d) (section d. of this condition). 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 40 C.F.R. §63.8(c)(7), the report must contain the information in 40 C.F.R. §63.10031(e) (condition 4.5.12.).

d. For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in 40 C.F.R. §63.10(e)(3)(v) in the compliance report specified in section a. of this condition.

e. If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

You must submit the report semiannually according to the requirements in 40 C.F.R. §60.10031(b) (condition 4.5.11.).

[40 C.F.R. §63.10031(a), Table 8, Item #1; 40 C.F.R. §§63.10031(c)(1) through (4) and (6) through (9); 40 C.F.R. §63.10031(d); 40 C.F.R. §63.10031(g); 40 C.F.R. §63.10021(i); 45CSR34]

4.5.11. Unless the Administrator has approved a different schedule for submission of reports under 40 C.F.R. §63.10(a), you must submit each report by the date in Table 8 to 40 C.F.R. 63 Subpart UUUUU and according to the requirements in paragraphs (1) through (5) of this condition.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in 40 C.F.R. §63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in 40 C.F.R. §63.9984.

(2) The first 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 first calendar half after the compliance date that is specified for your source in 40 C.F.R. §63.9984.

(3) 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.

(4) 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.

(5) You may submit the first and subsequent compliance reports according to the dates in permit condition 3.5.6. instead of according to the dates in paragraphs (1) through (4) of this condition.

[40 C.F.R. §§63.10031(b)(1) through (5); 45CSR34]

4.5.12. You must report all deviations as defined in 40 C.F.R. 63 Subpart UUUUU in the semiannual monitoring report required by condition 3.5.6. If an affected source submits a compliance report pursuant to Table 8 to 40 C.F.R. 63 Subpart UUUUU (condition 4.5.10.) along with, or as part of, the semiannual monitoring report required by condition 3.5.6., and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 C.F.R. 63 Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.
[40 C.F.R. §§63.10031(e); 45CSR34]

4.5.13. On or after July 1, 2020, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data; CEMS performance evaluation test results; reports for SO_2 CEMS and sorbent trap monitoring system; compliance reports; and all reports required by 40 C.F.R. 63 Subpart UUUUU not subject to the requirements in 40 C.F.R. §63.10031(f) introductory text and §§63.10031(f)(1) through (4) must be submitted as further specified in 40 C.F.R. §§63.10031(f), (f)(1), (3), (4), (5), and (6).
[40 C.F.R. §§ 63.10031(f), (f)(1), (3), (4), (5), and (6); 45CSR34]

4.6. Compliance Plan

4.6.1. There is no compliance plan since a responsible official certified compliance with all applicable requirements in the Title V renewal application.

5.0 Auxiliary Boiler [Emission Unit ID *Aux 1* – Emission Point ID *Aux ML1*]

5.1. Limitations and Standards

5.1.1. Emergency Operating Scenarios

a. In the event of an unavoidable shortage of fuel having characteristics or specifications necessary to comply with the visible emission requirements or any emergency situation or condition creating a threat to public safety or welfare, the Secretary may grant an exemption to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during that period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the weight emission requirements will not be exceeded during the exemption period.
[45CSR§2-10.1.]

b. Due to unavoidable malfunction of equipment or inadvertent fuel shortages, SO_2 emissions from the auxiliary boiler exceeding those provided for in 45CSR§§10-3.1.b. and 3.1.e., respectively, may be permitted by the Secretary for periods not to exceed ten (10) days upon specific application to the Secretary. Such application shall be made within twenty-four (24) hours of the equipment malfunction or fuel shortage. In cases of major equipment failure or extended shortages of conforming fuels, additional time periods may be granted by the Secretary, provided a corrective program has been submitted by the owner or operator and approved by the Secretary.
[45CSR§10-9.1.]

5.1.2. Any fuel burning unit(s) including associated air pollution control equipment, shall at all times, including periods of start-up, shutdowns, and malfunctions, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions.
[45CSR§2-9.2.]

5.1.3. The following conditions and requirements are specific to the Boiler Aux-1:

a. Emissions from the boiler shall not exceed the following limits:

Pollutant	lb/hr	tpy
SO_2	39.78[1]	17.42
NO_x	99.45	43.56
CO	206.86	90.60
VOC	0.95	0.41
PM (filterable + condensable)	15.63[2]	6.85
PM_{10} (filterable + condensable)	10.90	4.77
$PM_{2.5}$ (filterable + condensable)	7.34	3.22
CO_2	105,606.4	46,255.6
N_2O	0.88	0.38
CH_4	4.38	1.92
CO_{2e} (Total)	105,971.18	46,413.72
Formaldehyde	0.29	0.13
Benzene	0.01	0.01
Ethylbenzene	0.01	0.01

Toluene	0.03	0.02
Xylene	0.01	0.01
Naphthalene	0.01	0.01

[1] This limit makes 40 C.F.R. §60.42b(k)(2) applicable and excludes the unit from limitations of 40 C.F.R. §60.42b(k)(1). This limit satisfies the limitation in 45CSR§10-3.1.b. (4,972.5 lb/hr of SO_2).

[2] Compliance with this PM limitation ensures compliance with the 45CSR§2-4.1.b. limit of 59.67 lb/hr.

[45CSR§2-4.1.b.; 45CSR§10-3.1.b.]

b. Boiler Aux-1 shall be fitted with Low NO_x burners and shall utilize Flue Gas Recirculation.

c. The permittee shall limit the annual capacity of the boiler to no more than 10 percent by limiting the annual average heat input of the boiler to 580,788 MMBtu per year. Compliance with this limit shall be satisfied though compliance with the annual fuel usage limit in item d of this condition.
[40 C.F.R. §60.44b(c); 45CSR16; 40 C.F.R. §63.7575; 45CSR34; 45CSR§2-8.4.a.1.]

d. For the purpose of complying with the SO_2 limits in item a of this condition, the Boiler Aux-1 shall not consume more than 4,736 gallons of fuel oil (distillate oil) per hour nor more than 4,148,736 gallons per year. Such fuel oil can not contain more than 600 ppm or 0.06 % of sulfur, which makes the sulfur dioxide potential for this unit at no greater than 0.06 lb/MMBtu.
[40 C.F.R. §60.42b(k)(2), §60.43b(h)(5), and §60.48b(j)(2); 45CSR16; 45CSR§10-10.2]

e. Opacity from boiler shall not exceed 20% based on a 6-minute average, except for one 6-minute period per hour of not more than 27% opacity, except during periods of startup, shutdown, or malfunction.
[40 C.F.R. §§60.43b(f) & (g); 45CSR16]

f. Visible emissions from the boiler shall not exceed 10 percent opacity based on a six minute block average, except during periods of startup, shutdown, or malfunction.
[45CSR§§2-3.1. and 9.1.]

[45CSR13, R13-2608, 5.1.1.]

5.1.4. Compliance with the allowable sulfur dioxide emission limitations from the auxiliary boiler shall be based on a continuous twenty-four (24) hour averaging time. Emissions shall not be allowed to exceed the weight emissions standards for sulfur dioxide as set forth in 45CSR10, except during one (1) continuous twenty-four (24) hour period in each calendar month. During this one (1) continuous twenty-four hour period, emissions shall not be allowed to exceed such weight emission standards by more than ten percent (10%) without causing a violation of 45CSR10. A continuous twenty-four (24) hour period is defined as one (1) calendar day.
[45CSR§10-3.8.]

5.1.5. **Compliance Date for 40 C.F.R. 63 Subpart DDDDD.** If you have an existing boiler or process heater, you must comply with 40 C.F.R. 63 Subpart DDDDD no later than January 31, 2016, except as provided in 40 C.F.R. §63.6(i).
[40 C.F.R. §63.7495(b); 45CSR34]

5.1.6. **Periodic Tune-ups under 40 C.F.R. 63 Subpart DDDDD.** If your boiler meets the definition of limited-use boiler or process heater in 40 C.F.R. §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of 40 C.F.R. §63.7540 (paragraphs (i) through (vi) of this condition) to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (i) of this condition until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. 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;

(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 (you 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, if available, and with any NO_X requirement to which the unit is subject;

(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). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (vi)(A) and (B) of this condition.

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;
(B) A description of any corrective actions taken as a part of the tune-up.

- If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.
- Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up.

[40 C.F.R. §§ 63.7500(c), 63.7540(a)(10), 63.7540(a)(12), 63.7540(a)(13), 63.7505(a), 63.7515(d); 45CSR34; 45CSR13, R13-2608, 5.1.1.g. and 5.4.4.]

5.2. Monitoring Requirements

5.2.1. Compliance with the visible emission requirements for *Aux ML1* shall be determined as outlined in section I.B.2. of the DAQ approved “45CSR2 Monitoring Plan” attached in Appendix A of this permit.
[45CSR§§2-3.2. and 8.2.]

5.2.2. Compliance with the auxiliary boiler stack (*Aux ML1*) particulate matter mass emission requirements and the operating and fuel usage requirements for the auxiliary boiler, shall be demonstrated as outlined in section I.B.3. of the DAQ approved "45CSR2 Monitoring Plan" attached in Appendix A of this permit. **[45CSR§§2-8.3.c., 8.4.a. and 8.4.a.1.]**

5.2.3. In order to determine compliance with condition 5.1.3.d of this permit, the permittee shall monitor and record the amount of fuel oil combusted by Boiler Aux-1 on a monthly basis. Compliance with fuel usage limitations in item d will constitute compliance with the emission limitations of item a. of Condition 5.1.3. Such records shall be maintained in accordance with condition 3.4.2.
[45CSR13, R13-2608, 5.2.1.; 40 C.F.R. §60.49b(d)(2); 45CSR16; 45CSR§2-8.3.c.; 45CSR§§10-8.2.c.3. and 8.3.c.]

5.2.4. The permittee shall obtain records indicating the fuel oil received at the facility for Boiler Aux 1 meets the specification of distillate oil as defined in 40 C.F.R. §60.41b and sulfur content stated in item d. of condition 5.1.3. from the fuel supplier. Such records shall be maintained in accordance with condition 3.4.2. **[45CSR13, R13-2608, 5.2.2.; 40 C.F.R. §60.49b(r)(1); 45CSR16; 45CSR§10-8.2.c.3.]**

5.2.5. The permittee shall conduct subsequent visible emission observations of the emission point for Boiler Aux-1 at least once every 12 months from the date of the most recent observation. Such observations shall be conducted using Method 9 of Appendix A-4 of Part 60. If visible emissions are observed, the permittee must follow the subsequent observation schedule in 40 C.F.R. §60.48b(a)(1)(ii) through (iv) as applicable. Records of Method 9 observations shall contain the following:

a. Dates and time intervals of all opacity observation periods;
b. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and
c. Copies of all visible emission observer opacity field data sheets;

If the most recent observation is less than 10 percent opacity, the permittee may use Method 22 of Appendix A-7 of Part 60 to demonstrate compliance in lieu of using Method 9. The use of Method 22 observations must be in accordance with the length of observation and frequency as outlined in 40 C.F.R. §60.48b(a)(2)(i) through (ii) as applicable. Records of Method 22 observations shall contain the following:

a. Dates and time intervals of all visible emissions observation periods;
b. Name and affiliation for each visible emission observer participating in the performance test;
c. Copies of all visible emission observer opacity field data sheets; and
d. Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

Records of observations shall be maintained in accordance with condition 3.4.2.

[45CSR13, R13-2608, 5.2.3.; 40 C.F.R. §§60.48b(a) and 60.49b(f); 45CSR16; 45CSR§2-8.1.a.]

5.3. Testing Requirements

5.3.1. Reserved.

5.4. Recordkeeping Requirements

5.4.1. Records of monitored data established in the monitoring plan (see Appendix A) shall be maintained on site and shall be made available to the Secretary or his duly authorized representative upon request
[45CSR§2-8.3.a.]

5.4.2. Records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit, shall be maintained on-site in a manner to be established by the Secretary and made available to the Secretary or his duly authorized representative upon request
[45CSR§2-8.3.c.]

5.4.3. You must keep records according to paragraphs (1), (2), and (3) of this condition.

(1) A copy of each notification and report that you submitted to comply with 40 C.F.R. 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual* compliance report that you submitted, according to the requirements in 40 C.F.R. §63.10(b)(2)(xiv).
** Note – Compliance reports are required only once every 5 years for the limited use boiler Aux 1 pursuant to 40 C.F.R. §63.7550(b) in permit condition 5.5.5.*

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 C.F.R. §63.10(b)(2)(viii).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

[40 C.F.R. §§63.7555(a) and 63.7525(k); 45CSR34]

5.4.4. **Format and Retention of Records for 40 C.F.R. 63 Subpart DDDDD**

(a) Your records must be in a form suitable and readily available for expeditious review, according to 40 C.F.R. §63.10(b)(1).

(b) As specified in 40 C.F.R. §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 C.F.R. §63.10(b)(1). You can keep the records off site for the remaining 3 years.

[40 C.F.R. §§63.7560(a), (b), and (c); 45CSR34]

5.5. Reporting Requirements

5.5.1. A periodic exception report shall be submitted to the Secretary, in a manner and at a frequency to be established by the Secretary. Compliance with this periodic exception reporting requirement shall be demonstrated as outlined in section I.B.4. of the DAQ approved “45CSR2 and 45CSR10 Monitoring Plan” attached in Appendix A of this permit.
[45CSR§2-8.3.b.]

5.5.2. Excess opacity periods resulting from any malfunction of Aux 1 or its air pollution control equipment, meeting the following conditions, may be reported on a quarterly basis unless otherwise required by the Secretary:

a. The excess opacity period does not exceed thirty (30) minutes within any twenty-four (24) hour period; and

b. Excess opacity does not exceed forty percent (40%).

[45CSR§2-9.3.a.]

5.5.3. Except as provided in permit condition 5.5.2. above, the owner or operator shall report to the Secretary by telephone, telefax, or e-mail any malfunction of Aux1 or its associated air pollution control equipment, which results in any excess particulate matter or excess opacity, by the end of the next business day after becoming aware of such condition. The owner or operator shall file a certified written report concerning the malfunction with the Secretary within thirty (30) days providing the following information:

a. A detailed explanation of the factors involved or causes of the malfunction;

b. The date, and time of duration (with starting and ending times) of the period of excess emissions;

c. An estimate of the mass of excess emissions discharged during the malfunction period;

d. The maximum opacity measured or observed during the malfunction;

e. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction; and

f. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.b.]

5.5.4. You must report each instance in which you did not meet each work practice standard in Table 3 to 40 C.F.R. 63 Subpart DDDDD that applies to you (condition 5.1.6.). These instances are deviations from the work practice standards in 40 C.F.R. 63 Subpart DDDDD. These deviations must be reported according to the requirements in 40 C.F.R. §63.7550 (condition 5.5.5.).
[40 C.F.R. §63.7540(b); 45CSR34]

5.5.5. You must submit a Compliance report for 40 C.F.R. 63 Subpart DDDDD containing:

a. The information in §63.7550(c)(5)(i) through (iv), (xiv), and (xvii), which is:

(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 C.F.R. §63.7540(a)(12). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled or unscheduled unit shutdown.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

b. If there are no deviations from the requirements for work practice standards in Table 3 to 40 C.F.R. 63 Subpart DDDDD that apply to you (condition 5.1.6.), a statement that there were no deviations from the work practice standards during the reporting period.

You must submit the report every 5 years according to the requirements in 40 C.F.R. §63.7550(b), which are:

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 C.F.R. §63.7495 (condition 5.1.5.) and ending on July 31 or January 31, whichever date is the first date that occurs at least 5 years after the compliance date that is specified for your source in 40 C.F.R. §63.7495 (condition 5.1.5.).

(2) The first 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent 5-year compliance report must cover the 5-year periods from January 1 to December 31.

(4) Each subsequent 5-year compliance report must be postmarked or submitted no later than January 31.

(5) You may submit the first and subsequent compliance reports according to the dates established in permit condition 3.5.6. instead of according to the dates in paragraphs b. (1) through (4) of this condition.

You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[40 C.F.R. §§63.7550(a), Table 9, Items # 1.a. and # 1.b.; 40 C.F.R. §§63.7550(b), and (c)(1); 40 C.F.R. §63.7550(h)(3); 45CSR34; 45CSR13, R13-2608, 5.5.2.]

5.5.6. The permittee shall report any observation made in accordance with Condition 5.2.5. that indicate visible emissions in excess of either items e and/or f of condition 5.1.3. made during January 1 to June 30 in the facility's Title V Semi Annual Compliance Report or July 1 to December 31 as part of the facility's Title V Annual Compliance Report. Such report shall include the record of the recorded observation in accordance with condition 5.2.5. and measures taken as result of the observation. This reporting requirement can be satisfied by including the results of the exceeded observation(s) with the facility's quarterly opacity report and list the exceedance in the facility's Title V annual compliance certification report.
[45CSR13, R13-2608, 5.5.3.; 40 C.F.R. §60.49b(h); 45CSR16; 45CSR§2-8.3.b.]

5.6. Compliance Plan

5.6.1. Reserved.

6.0 Material Handling [Emission point IDs identified in Equipment Table subsection 1.1.]

7.1. Limitations and Standards

6.1.1. Limestone transferred across belt conveyor BC-1 to Transfer House #1 [TH-1] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.
[45CSR13, R13-2608, 4.1.1.]

6.1.2. Limestone transferred across belt conveyor BC-3 to Transfer House #2 [TH-2] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.
[45CSR13, R13-2608, 4.1.2.]

6.1.3. Gypsum transferred across belt conveyor BC-9 to Transfer House #4 [TH-4] shall be limited to a maximum transfer rate of 200 tons per hour and 1,700,000 tons per year.
[45CSR13, R13-2608, 4.1.3.]

6.1.4. Gypsum and wastewater treatment system cake transferred across belt conveyor BC-14 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,912,000 tons per year.
[45CSR13, R13-2608, 4.1.4.]

6.1.5. Gypsum transferred across belt conveyor BC-17 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 750 tons per hour and 1,200,000 tons per year.
[45CSR13, R13-2608, 4.1.5.]

6.1.6. Gypsum transferred across belt conveyor BC-19 to Transfer House #9 [TH-9] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,700,000 tons per year.
[45CSR13, R13-2608, 4.1.6.]

6.1.7. Coal transferred across belt conveyor HSC-1 shall be limited to a maximum transfer rate of 3,000 tons per hour and 5,732,544 tons per year.
[45CSR13, R13-2608, 4.1.7.]

6.1.8. Dry Sorbent (Trona or Hydrated Lime) for SO_3 mitigation shall be delivered to the facility at a maximum annual rate of 81,000 tons per year.
[45CSR13, R13-2608, 4.1.8.]

6.1.9. Liquid magnesium hydroxide shall be delivered to the facility at a maximum annual rate of 6,600,000 gallons per year.
[45CSR13, R13-2608, 4.1.9.]

6.1.10. Hydrated lime for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 3,200 tons per year.
[45CSR13, R13-2608, 4.1.10.]

6.1.11. Ferric Chloride for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 110,000 gallons per year.
[45CSR13, R13-2608, 4.1.11.]

6.1.12. Acid (hydrochloric or sulfuric) for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 170,000 gallons per year.
[45CSR13, R13-2608, 4.1.12.]

6.1.13. Polymer and organosulfide for the FGD wastewater treatment facility shall be delivered to the facility at a maximum annual rate of 13,500 gallons per year.
[45CSR13, R13-2608, 4.1.13.]

6.1.14. The diesel-fired engines [6S and 7S] used to power the emergency quench water system shall be limited to a total maximum combined annual operating schedule of 200 hours per year.
[45CSR13, R13-2608, 4.1.14.]

6.1.15. Compliance with all annual operating limits shall be determined using a twelve month rolling total. A twelve month rolling total shall mean the sum of the quantified operating data at any given time during the previous twelve (12) consecutive calendar months.
[45CSR13, R13-2608, 4.1.15.]

6.1.16. The permittee shall maintain a water truck on site and in good operating condition, and shall utilize same to apply water as often as is necessary in order to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads and other work areas where mobile equipment is used. The spraybar shall be equipped with spray nozzles, of sufficient size and number, so as to provide adequate coverage to the area being treated.

The pump delivering the water shall be of sufficient size and capacity so as to be capable of delivering to the spray nozzle(s) an adequate quantity of water and at a sufficient pressure, so as to assure that the treatment process will minimize the atmospheric entrainment of fugitive particulate emissions generated from the haulroads and work areas where mobile equipment is used.

[45CSR13, R13-2608, 4.1.16.]

6.1.17. Additionally, at least three times per year the permittee shall apply a mixture of water and an environmentally acceptable dust control additive hereafter referred to as solution to all unpaved haul roads. The solution shall have a concentration of dust control additive sufficient to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads.
[45CSR13, R13-2608, 4.1.17.]

6.1.18. The installation and operation of the proposed Limestone Material Handling equipment [1S] and Limestone Processing equipment [3S] shall be subject to the limits and requirements set forth by 40 C.F.R. 60 - Subpart OOO, *"Standards of performance for non-metallic mineral processing plants."*

a. The material transfers across the conveyors within the enclosed transfer stations and ball mill within the processing building will be limited to the opacity emissions from the building or building vents. The buildings will be limited to emissions of no visible opacity per 40 C.F.R. §60.672(e)(1), and the vents from the buildings will be limited to an opacity of 7% and particulate emissions of 0.022 grains per dry standard cubic foot, per 40 C.F.R. §60.672(e)(2).

b. The emissions from the baghouse on each of the limestone day bins will be limited to 7% opacity per 40 C.F.R. §60.672(f).

c. All material transfer points outside of the buildings will be limited to a maximum 10% opacity per 40 C.F.R. §60.672(b).

d. In order to comply with the emission and opacity limitations of 40 C.F.R. 60 Subpart OOO, the permittee shall employ dust suppression methods to minimize particulate emissions from the limestone processing equipment. In order to demonstrate compliance, in accordance to the requirements of the regulation, the applicant shall conduct performance testing and monitoring activities as set forth by 40 C.F.R. 60 Subpart OOO.

[45CSR13, R13-2608, 4.1.19.; 40 C.F.R. Part 60, Subpart OOO; 45CSR16]

6.1.19. The maximum amount of fly ash handled by the fly ash handling system shall not exceed 800,000 tons per year on a dry (1% moisture) basis (i.e. 980,000 tons per year at 20% moisture). Compliance with the throughput limit shall be determined using a rolling yearly total. A rolling yearly total shall mean the sum of the fly ash transferred for the previous twelve (12) consecutive calendar months.
[45CSR13, R13-2608, 4.1.20.]

6.1.20. PM emissions from Mechanical Exhausters ME-1A, ME-1B and ME-1C shall not exceed 0.16 lb/hr and 0.69 tpy individually nor 0.32 lb/hr and 1.38 tons per year combined.
[45CSR13, R13-2608, 4.1.21.]

6.1.21. PM emissions from Mechanical Exhausters ME-2A, ME-2B and ME-2C shall not exceed 0.15 lb/hr and 0.65 tpy individually nor 0.30 lb/hr and 1.30 tons per year combined.
[45CSR13, R13-2608, 4.1.22.]

6.1.22. PM emissions from Bin Vent Filters BVF-A, BVF-B and BVF-C shall not exceed 0.75 lb/hr nor 3.25 tpy combined.
[45CSR13, R13-2608, 4.1.23.]

6.1.23. PM emissions from the transfer of conditioned fly ash from the silos to trucks (WFA-AA, WFA-AB, WFA-BA, WFA-BB, WFA-CA, and WFA-CB) shall not exceed 0.07 pounds per hour nor 0.09 tons per year combined.
[45CSR13, R13-2608, 4.1.24.]

6.1.24. The Coal and Ash handling systems, and FGD and SCR material handling systems, are subject to 45CSR§2-5 as outlined in the facility wide section of this permit (condition 3.1.9.) regarding fugitive dust control system.

6.1. Monitoring Requirements

6.2.1. For the purpose of determining compliance with the material transfer limits set forth by Section 6.1.1. and 6.1.2. of this permit, the permittee shall monitor the hourly and annual limestone transfer rates across belt conveyor BC-1 to Transfer House #1 [TH-1] and across belt conveyor BC-3 to Transfer House #2 [TH-2].
[45CSR13, R13-2608, 4.2.1.]

6.2.2. For the purpose of determining compliance with the material transfer limits set forth by Sections 6.1.3., 6.1.4., 6.1.5. and 6.1.6. of this permit, the permittee shall monitor the hourly and annual gypsum and wastewater treatment cake transfer rates across belt conveyors BC-9 to Transfer House #4 [TH-4], BC-14 to Transfer House #7 [TH-7], BC-17 to the Transfer House #7 Extension, and BC-19 to Transfer House #9 [TH-9].
[45CSR13, R13-2608, 4.2.2.]

6.2.3. For the purpose of determining compliance with the material transfer limits set forth by Section 6.1.7. of this permit, the permittee shall monitor the hourly and annual coal transfer rates across belt conveyor HSC-1 to Transfer Station #2A.
[45CSR13, R13-2608, 4.2.3.]

6.2.4. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the SO_3 mitigation system, as set forth by Section 6.1.8. and 6.1.9. of this permit, the permittee shall monitor the on-site delivery of dry sorbent (including trona and hydrated lime) and liquid magnesium hydroxide.
[45CSR13, R13-2608, 4.2.4.]

6.2.5. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the FGD wastewater treatment system, as set forth by Sections 6.1.10. through 6.1.13. of this permit, the permittee shall monitor the on-site delivery of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide.
[45CSR13, R13-2608, 4.2.5.]

6.2.6. For the purpose of determining compliance with the operating limits set forth by Section 6.1.14. of this permit, the permittee shall monitor the operating schedule of the diesel-fired engines [6S and 7S] used to power the emergency quench water system.
[45CSR13, R13-2608, 4.2.6.]

6.2.7. For the purpose of determining compliance with the limits associated with disposal of dry fly ash, as set forth by Section 6.1.19 of this permit, the permittee shall monitor and record the amount of dry fly ash disposed of.
[45CSR13, R13-2608, 4.2.7.]

6.2.8. For the purpose of determining compliance with the operating limits set forth by Section 6.1.17. of this permit, the permittee shall monitor and record the date that chemical solution is applied to the haulroads along with the amount and concentration of the solution applied.
[45CSR13, R13-2608, 4.2.8.]

6.2. Testing Requirements

6.3.1. Within 120 days of startup of the dry ash handling system, the permittee shall perform or have performed EPA approved tests (or other methods as approved by WVDAQ) to determine maximum PM emissions from any one of the Silo Bin Vent Filters (BVF-A, BVF-B or BVF-C).
[45CSR13, R13-2608, 4.3.2.]

6.3. Recordkeeping Requirements

6.4.1. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.1. of this permit, the permittee shall maintain monthly records of the amount of limestone transferred across the monitored belt conveyors.
[45CSR13, R13-2608, 4.4.4.]

6.4.2. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.2. of this permit, the permittee shall maintain monthly records of the amount of gypsum and wastewater treatment cake transferred across the monitored belt conveyors.
[45CSR13, R13-2608, 4.4.5.]

6.4.3. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.3. of this permit, the permittee shall maintain monthly records of the amount of coal transferred across the monitored belt conveyor.
[45CSR13, R13-2608, 4.4.6.]

6.4.4. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.4. of this permit, the permittee shall maintain monthly records of the amount of dry sorbent (trona and hydrated lime) and liquid magnesium hydroxide delivered to the facility via truck.
[45CSR13, R13-2608, 4.4.7.]

6.4.5. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.5. of this permit, the permittee shall maintain monthly records of the amount of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide delivered to the facility via truck.
[45CSR13, R13-2608, 4.4.8.]

6.4.6. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 6.2.6. of this permit, the permittee shall maintain monthly records of the hours of operation of the diesel-fired engines [6S and 7S].
[45CSR13, R13-2608, 4.4.9.]

6.4.7. For the purposes of determining compliance with Section 6.1.16., 6.1.17., and 3.1.9. of this permit, the permittee shall maintain records of the amount of dust control additive used at the facility and the dates the solution was applied.
[45CSR13, R13-2608, 4.4.10.]

6.4.8. All records produced in accordance to the requirements set forth by Sections 6.4.1. through 6.4.7. of this permit shall be maintained in accordance with Section 3.3.4. of this permit. At a time prior to being submitted to the Director, all records shall be certified and signed by a “Responsible Official” or a duly authorized representative, utilizing the attached Certification of Data Accuracy statement (Appendix B).
[45CSR13, R13-2608, 4.4.11.]

6.4.9. For the purposes of determining compliance with the maximum throughput limit set forth in Condition 6.1.19. above, the facility shall maintain monthly (and calculated rolling yearly total) records of the amount of fly ash handled by the Units 1 and 2 fly ash system.
[45CSR13, R13-2608, 4.4.12.]

6.4. Reporting Requirements

6.5.1. Reserved.

6.5. Compliance Plan

6.6.1. A compliance plan is not included since a Responsible Official certified compliance with all applicable requirements in the renewal application.

7.0 Emergency Quench Water Pump Diesel-fired Engines [emission unit IDs: 6S, 7S; emission point IDs: 15E, 16E]

7.1. Limitations and Standards

7.1.1. If you have an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013.
[40 C.F.R. §63.6595(a)(1); 45CSR34]

7.1.2. For emergency stationary CI RICE[1], you must meet the following requirements, except during periods of startup:

a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]
b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;
c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]

During periods of startup you must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of 40 C.F.R. 63 Subpart ZZZZ, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in 40 C.F.R. §63.6625(i) (permit condition 7.1.6.) in order to extend the specified oil change requirement in Table 2c of 40 C.F.R. 63 Subpart ZZZZ.

[3] Sources can petition the Administrator pursuant to the requirements of 40 C.F.R. §63.6(g) for alternative work practices.

[40 C.F.R. §63.6602, Table 2c, Row 1; 40 C.F.R. §63.6625(h); 45CSR34]

7.1.3. At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator 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 C.F.R. §63.6605(b); 45CSR34]

7.1.4. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
[40 C.F.R. §§63.6625(e) and 63.6625(e)(2); 40 C.F.R. §63.6640(a), Table 6, Item #9; 45CSR34]

7.1.5. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.
[40 C.F.R. §63.6625(f); 45CSR34]

7.1.6. If you own or operate a stationary CI engine that is subject to the work, operation or management practices in item 1 of table 2c to 40 C.F.R. 63 Subpart ZZZZ (permit condition 7.1.2.), you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in table 2c to 40 C.F.R. 63 Subpart ZZZZ. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c to 40 C.F.R. 63 Subpart ZZZZ (permit condition 7.1.2.a.). The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine (permit condition 7.1.4.).
[40 C.F.R. §63.6625(i); 45CSR34]

7.1.7. If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (1) through (3) of this condition. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (1) through (3) of this condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this condition, the engine will not be considered an emergency engine under 40 C.F.R. 63 Subpart ZZZZ and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (2)(i) of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this condition counts as part of the 100 hours per calendar year allowed by this paragraph (2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (2) of this condition. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[40 C.F.R. §§63.6640(f) and 63.6640(f)(1), (f)(2), and (f)(3); 45CSR34]

7.2. Monitoring Requirements

7.2.1. Reserved.

7.3. Testing Requirements

7.3.1. Reserved.

7.4. Recordkeeping Requirements

7.4.1. You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan (permit condition 7.1.4.) if you own or operate an existing stationary emergency RICE.
[40 C.F.R. §§63.6655(e) and 63.6655(e)(2); 45CSR34]

7.4.2. If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 C.F.R. §63.6640(f)(2)(ii) or (iii) (condition 7.1.7.(2)(ii) or (iii)), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.
[40 C.F.R. §§63.6655(f) and 63.6655(f)(1); 45CSR34]

7.4.3. **Form and Retention of Records for 40 C.F.R. 63 Subpart ZZZZ**.

(a) Your records must be in a form suitable and readily available for expeditious review according to 40 C.F.R. §63.10(b)(1).

(b) As specified in 40 C.F.R. §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 C.F.R. §63.10(b)(1).

[40 C.F.R. §§63.6660(a), (b), and (c); 45CSR34]

7.5. Reporting Requirements

7.5.1. You must report each instance in which you did not meet each limitation in Table 2c to 40 C.F.R. 63 Subpart ZZZZ (permit condition 7.1.2.). These instances are deviations from the emission and operating limitations in 40 C.F.R. 63 Subpart ZZZZ. These deviations must be reported according to the requirements in 40 C.F.R. §63.6650 (permit condition 7.5.3.).
[40 C.F.R. §63.6640(b); 45CSR34]

7.5.2. You must also report each instance in which you did not meet the requirements in Table 8 to 40 C.F.R. 63 Subpart ZZZZ that apply to you.
[40 C.F.R. §63.6640(e); 45CSR34]

7.5.3. The permittee must report all deviations as defined in 40 C.F.R. 63 Subpart ZZZZ in the semiannual monitoring report required by permit condition 3.5.6.
[40 C.F.R. §63.6650(f); 45CSR34]

7.6. Compliance Plan

7.6.1. A compliance plan is not included since a Responsible Official certified compliance with all applicable requirements in the renewal application.

8.0 Liquid Propane Vapor Engine Driven Emergency Generator, Black Start Emergency Generators, Diesel Fuel Storage Tank, Diesel Driven Emergency Generators, and Diesel Driven Emergency Fire Pump Engines [emission point ID(s): LPG, EG-1, EG-2, EGT01, EGT02, LF DEG, LF DEG2, 17E and 18E]

8.1. Limitations and Standards

8.1.1. **Emission Limitations**. The registrant shall not cause, suffer, allow or permit emissions of VOC, NO_X, and CO, from any registered reciprocating internal combustion engine to exceed the potential to emit (pounds per hour and tons per year) listed in the General Permit Registration.

Source ID#	Nitrogen Oxides		Carbon Monoxide		Volatile Organic Compounds	
	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]
LPG	0.74	0.19	21.75	5.44	0.22	0.06
EG-1	59.9	14.98	7.66	1.92	0.94	0.24
EG-2	36.4	9.1	4.85	1.21	1.18	0.30
TOTAL	97.04	24.27	34.26	8.57	2.34	0.60

[1] Based on operating the engine 500 hours per year. Compliance with the yearly limitations shall be determined using a twelve-month rolling total. A twelve-month rolling total shall mean the sum of the hours or operation at any given time during the previous twelve consecutive calendar months.

[45CSR13, G60-C057 General Permit Registration, Emission Limitations; General Permit G60-D, Conditions 5.1.2. and 5.1.3.]

8.1.2. The applicable emergency generator(s) shall be operated and maintained as follows:

a. In accordance with the manufacturer's recommendations and specifications or in accordance with a site-specific maintenance plan; and,

b. In a manner consistent with good operating practices.

[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.4.]

8.1.3. The emission limitations specified in section 8.1.1. shall apply at all times except during periods of start-up and shut-down provided that the duration of these periods does not exceed 30 minutes per occurrence. The registrant shall operate the engine in a manner consistent with good air pollution control practices for minimizing emissions at all times, including periods of start-up and shut-down. The emissions from start-up and shut-down shall be included in the twelve (12) month rolling total of emissions. The registrant shall comply with all applicable start-up and shut-down requirements in accordance with 40 CFR Part 60, Subparts IIII, JJJJ and 40 CFR Part 63, Subpart ZZZZ.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.7.]

8.1.4. All tanks in the General Permit Registration application will be listed in Section 1.0 (the emission unit table) of the issued registration. Tanks are to be used for fuel storage for the emergency generators (EG-1, EG-2) only.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 6.1.1.] (EGT01, EGT02)

8.1.5. **40 C.F.R. 60 Subpart IIII – Manufacturer Certification**.

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of 40 C.F.R. §60.4202.

(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.

[40 C.F.R. §§ 60.4205(b) and 60.4202(a)(2); 40 C.F.R. §1039, Appendix I; 45CSR16] (LF DEG, LF DEG2)

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraph (2) of this condition.

(2) For 2011 model year and later, the Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

NMHC+NOx (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
6.4	3.5	0.20

[40 C.F.R. §§ 60.4205(b) and 60.4202(b)(2); 40 C.F.R. §1039, Table 2 to Appendix I; 45CSR16; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2)

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

[40 C.F.R. §§ 60.4205(c) and 60.4202(d); 45CSR16] (17E, 18E)

8.1.6. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §60.4205 (condition 8.1.5.) over the entire life of the engine.
[40 C.F.R. §60.4206; 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2, 17E, 18E)

8.1.7. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to 40 C.F.R. 60 Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel.

(1) Sulfur content - 15 ppm maximum

(2) Cetane index or aromatic content as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

[40 C.F.R. §60.4207(b); 40 C.F.R. §§ 1090.305(b), (c)(1), and (c)(2); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2, 17E, 18E)

8.1.8. a. If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under Condition 8.1.8.c. of this permit:

1. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

2. Change only those emission-related settings that are permitted by the manufacturer; and

3. Meet the requirements of 40 CFR part 1068, as they apply to you.

b. If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in Condition 8.1.5. of this permit, or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in Condition 8.1.5. for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in Condition 8.1.8.c. of this permit.

c. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. **(LF DEG, 17E, 18E)**

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the

manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards. **(EG-1, EG-2, LF DEG2)**

[40 C.F.R. §§ 60.4211(a), (c), (g), (g)(2), and (g)(3); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2)

8.1.9. If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (1) through (3) of this condition. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (1) through (3) of this condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this condition, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (2)(i) of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this condition counts as part of the 100 hours per calendar year allowed by this paragraph (2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing in paragraph (2) of this condition. Except as provided in paragraph (3)(i) of this condition, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[40 C.F.R. §60.4211(f); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2, 17E, 18E)

8.1.10. Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) must comply with the emission standards in Table 1 to 40 C.F.R. 60 Subpart JJJJ for their stationary SI ICE.

NO_x (g/HP-hr)	CO (g/HP-hr)
10 (1)	387

(1) The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X + HC.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4233(e) and Table 1 of 40 C.F.R. 60 Subpart JJJJ; 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.11. Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 (condition 8.1.10.) over the entire life of the engine. *Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).*
[40 C.F.R. §60.4234; 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.12. If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine. *Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).*
[40 C.F.R. §60.4237(c); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.13. If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (1) through (3) of this condition. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (1) through (3) of this condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this condition, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (2)(i) of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this condition counts as part of the 100 hours per calendar year allowed by this paragraph (2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (2) of this condition. Except as provided in paragraph (3)(i) of this condition, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;
(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
(D) The power is provided only to the facility itself or to support the local transmission and distribution system.
(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4243(d); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (LPG)

8.1.14. *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of 40 C.F.R. §63.6590 must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[40 C.F.R. §§63.6590(c)(6) and (c)(7), 45CSR34] [LF DEG]

8.1.15. *Stationary RICE subject to Regulations under 40 CFR Part 60.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of 40 C.F.R. §63.6590 does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

[40 C.F.R. §§63.6590(b)(1)(i), 45CSR34] [LF DEG2]

8.2. Monitoring Requirements

8.2.1. If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.
[40 C.F.R. §60.4209(a); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Condition 5.1.6.] (EG-1, EG-2) (LF DEG, LF DEG2) (17E, 18E)

8.3. Testing Requirements

8.3.1. Reserved.

8.4. Recordkeeping Requirements

8.4.1. To demonstrate compliance with permit condition 8.1.1., the registrant shall maintain records of the hours of operation of the emergency generators on a monthly basis.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.3.1.]

8.4.2. To demonstrate compliance with permit condition 8.1.2., the registrant shall maintain records of the maintenance performed on each emergency generator.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.3.2.]

8.4.3. All records required by conditions 8.4.1. and 8.4.2. shall be maintained in accordance with condition 3.4.2. of this permit.
[45CSR13, G60-C057 General Permit Registration; General Permit G60-D, Condition 5.3.5.]

8.4.4. If the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
[40 C.F.R. §60.4214(b); 45CSR16; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (EG-1, EG-2) (LF DEG, LF DEG2) (17E, 18E)

8.4.5. If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(e) (condition 8.1.10.), you must demonstrate compliance according to the method specified in paragraph (1) of this condition.

(1) Purchasing an engine certified according to procedures specified in 40 C.F.R. 60 Subpart JJJJ, for the same model year and demonstrating compliance according to the method specified in paragraph (a) of 40 C.F.R. §60.4243:

i. If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

ii. If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(ii) of §60.4243:

- If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

  Note: The 2019 renewal application does not indicate that the manufacturer-certified engine LPG will not be operated and maintained according to the manufacturer's emission-related written instructions; therefore, condition 8.4.5.(1) i. is applicable.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §§ 60.4243(b) and (b)(1); 40 C.F.R. §§ 60.4243(a)(1) and (a)(2)(ii); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (LPG)

8.4.6. Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (1) through (4) of this condition.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2) (condition 8.4.5.(1) ii.), documentation that the engine meets the emission standards.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4245(a); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (LPG)

8.4.7. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. *Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).*
[40 C.F.R. §60.4245(b); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.3.4.] (LPG)

8.5. Reporting Requirements

8.5.1. If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in §60.4243(d) (3)(i) (permit condition 8.1.13.), you must submit an annual report according to the requirements in paragraphs (1) through (3) of this condition.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(vii) Hours spent for operation for the purposes specified in §60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section.

Compliance with the applicable requirements of 40 C.F.R. 60 Subpart JJJJ meets the requirements of 40 C.F.R. 63 Subpart ZZZZ in accordance with 40 C.F.R. §§ 63.6590(c) and (c)(3).

[40 C.F.R. §60.4245(e); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.2. Beginning on February 26, 2025, within 60 days after the date of completing each performance test, you must submit the results following the procedures specified in this condition. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or an alternate electronic file.

[40 C.F.R. §60.4245(f); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.3. If you are required to submit notifications or reports following the procedure specified in this condition, you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (1) and (2) of this condition. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the

attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

[40 C.F.R. §60.4245(g); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.4. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (1) through (7) of this condition.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

[40 C.F.R. §60.4245(h); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.5. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (1) through (5) of this condition.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

[40 C.F.R. §60.4245(i); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.6. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[40 C.F.R. §60.4245(j); 45CSR16; 40 C.F.R. §§ 63.6590(c) and (c)(3); 45CSR34; G60-C057 General Permit Registration; General Permit G60-D, Conditions 5.1.6. and 5.5.1.] (LPG)

8.5.7. If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in 40 C.F.R. §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(vii) Hours spent for operation for the purposes specified in 40 C.F.R. §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in 40 C.F.R. §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 C.F.R. §60.4. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section.

[40 C.F.R. §60.4214(d); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.8. Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test required under this section following the procedures specified in paragraphs (1) and (2) of this condition.

(1) Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test. Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to condition 8.5.9. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test. The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to paragraph (g) of this section.

[40 C.F.R. §60.4214(f); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.9. If you are required to submit notifications or reports following the procedure specified in this condition, you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (1) and (2) of this condition. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Spark Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

[40 C.F.R. §60.4214(g); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.10. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (1) through (7) of this condition.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

[40 C.F.R. §60.4214(h); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.11. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (1) through (5) of this condition.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

[40 C.F.R. §60.4214(i); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.5.12. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[40 C.F.R. §60.4214(j); 45CSR16] (EG-1, EG-2, LF DEG, LF DEG2, 17E, 18E)

8.6. Compliance Plan

8.6.1. Reserved.

9.0 Landfill Building Furnace CB-325

9.1. Limitations and Standards

9.1.1. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.
[45CSR§2-3.1.]

9.1.2. Compliance with the visible emission requirements of subsection 3.1 (permit condition 9.1.1.) shall be determined in accordance with 40 CFR Part 60, Appendix A, Method 9 or by using measurements from continuous opacity monitoring systems approved by the Director. The Director may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of subsection 3.1. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.
[45CSR§2-3.2.]

9.1.3. **Exemption from 45CSR2 monitoring, testing, recordkeeping, and reporting**. Any fuel burning unit(s) having a heat input under ten (10) million B.T.U.'s per hour will be exempt from sections 4, 5, 6, 8 and 9 of 45CSR2. However, failure to attain acceptable air quality in parts of some urban areas may require the mandatory control of these sources at a later date.
[45CSR§2-11.1.]

9.2. Monitoring Requirements

9.2.1. At such reasonable times as the Director may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with condition 9.1.1. Method 9 shall be conducted in accordance with 40 CFR Part 60 Appendix A.
[45CSR§30-5.1.c.]

9.3. Testing Requirements

9.3.1. Reserved.

9.4. Recordkeeping Requirements

9.4.1. Reserved.

9.5. Reporting Requirements

9.5.1. Reserved.

9.6. Compliance Plan

9.6.1. Reserved.

APPENDIX A

45CSR2 & 45CSR10 Monitoring Plan

45 CSR 2 and 45 CSR 10
Monitoring and Recordkeeping Plan

Mitchell Plant

Facility Information:

Facility Name:Mitchell Plant

Facility Address: P.O. Box K
State Route 2
Moundsville, WV 26041

Facility Environmental Contact: Mr. G. M. (Matt) Palmer
Plant Environmental Coordinator

A. Facility Description:

Mitchell Plant is a coal-fired electric generating facility with two main combustion units (Units 1 and 2) discharging through a common stack shell that utilizes two separate stack discharge flues. Mitchell plant also has an auxiliary boiler (Aux. 1) that discharges through an independent auxiliary stack (Aux ML1). Unit 1, Unit 2, and Aux. Boiler 1 each have a design heat input greater than 10 mmBTU/hr making both 45 CSR 2A (Interpretive Rule for 45 CSR 2) and 45 CSR 10A (Interpretive Rule for 45 CSR 10) applicable to these sources.

I. 45 CSR 2 Monitoring Plan:

In accordance with Section 8.2.a of 45 CSR 2, following is the proposed plan for monitoring compliance with opacity limits found in Section 3 of that rule:

A. Main Stack (1E, 2E)

1. Applicable Standard:

   45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method(s):

   45 CSR 2, §3.2. *...Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emissions control.*

45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

a. Primary Monitoring Method: While a Continuous Opacity Monitoring System (COMS) would not be required on a wet scrubbed fuel burning unit, Mitchell Plant has chosen to employ COMS on each of the fuel burning units upstream of the wet scrubbers and located in plant ductwork. As such, the primary method of monitoring opacity at Mitchell Plant will be Continuous Opacity Monitors (COMS). The COMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75.

b. Other Credible Monitoring Method(s): While Mitchell Plant will use COMS as the primary method of monitoring opacity of the fuel burning units, we are also reserving the right to use other appropriate method that would produce credible data. These "other monitoring methods" will generally be used in the absence of COMS data or as other credible evidence used in conjunction with COMS data.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned**

45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

The applicable paragraphs for Mitchell Plant are the following:

§7.1.a.2: *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

§7.1.a.4: *For fuel burning unit(s) which burn only coal, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a daily basis and an ash and BTU analysis for each shipment.*

§7.1.a.6: *For fuel burning unit(s) which burn a combination of fuels, the owner or operator shall comply with the applicable Recordkeeping requirements of paragraph 7.1.a.1 through 7.1.a.5 for each fuel burned.*

The date and time of each startup and shutdown of Units 1 and 2 will be maintained. The quantity of coal burned on a daily basis as well as the ash and Btu content will also be maintained. From a fuel oil perspective, the quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

b. **Record Maintenance**

45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.

4. Exception Reporting:

a. **Particulate Mass Emissions:**

45 CSR 2A, §7.2.a. *With respect to excursions associated with measured emissions under Section 4 of 45CSR2, compliance with the reporting and testing requirements under the Appendix to 45CSR2 shall fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45CSR2*.

Mitchell Plant will comply with the reporting and testing requirements specified under the Appendix to 45 CSR 2.

b. **Opacity:**

45 CSR 2A, §7.2.b. *COMS – In accordance with the provisions of this subdivision, each owner or operator employing COMS as the method of monitoring compliance with opacity limits shall submit a "COMS Summary Report" and/or an "Excursion and COMS Monitoring System Performance Report" to the Director on a quarterly basis; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the fuel burning unit(s). All reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter. The COMS Summary Report shall contain the information and be in the format shown in Appendix B unless otherwise specified by the Director.*

45 CSR 2A, §7.2.b.1. *If the total duration of excursions for the reporting period is less than one percent (1%) of the total operating time for the reporting period and monitoring system downtime for the reporting period is less than five percent (5%) of the total operating time for the reporting period, the COMS Summary Report shall be submitted to the Director; the Excursion and COMS Monitoring System Performance report shall be maintained on-site and shall be submitted to the Director upon request.*

45 CSR 2A, §7.2.b.2. *If the total duration of excursions for the reporting period is one percent (1%) or greater of the total operating time for the reporting period or the total monitoring system downtime for the reporting period is five percent (5%) or greater of the total operating time for the reporting period, the COMS Summary Report and the Excursion and COMS Monitoring System Performance Report shall both be submitted to the Director.*

45 CSR 2A, §7.2.b.3. *The Excursion and COMS Monitoring System Performance Report shall be in a format approved by the Director and shall include, but not be limited to, the following information:*

45 CSR 2A, §7.2.b.3.A. *The magnitude of each excursion, and the date and time, including starting and ending times, of each excursion.*

45 CSR 2A, §7.2.b.3.B. *Specific identification of each excursion that occurs during start-ups, shutdowns, and malfunctions of the facility.*

45 CSR 2A, §7.2.b.3.C. *The nature and cause of any excursion (if known), and the corrective action taken and preventative measures adopted (if any).*

45 CSR 2A, §7.2.b.3.D. *The date and time identifying each period during which quality- controlled monitoring data was unavailable, except for zero and span checks, and the reason for data unavailability and the nature of the repairs or adjustments to the monitoring system.*

45 CSR 2A, §7.2.b.3.E. *When no excursions have occurred or there were no periods of quality-controlled data unavailability, and no monitoring systems were inoperative, repaired, or adjusted, such information shall be stated in the report.*

Attached, as Appendices A and B are sample copies of a typical COMS "Summary Report" and "Excess opacity and COM downtime report" that we plan on using to fulfill the opacity reporting requirements. The COMS "Summary Report" will satisfy the conditions under 45 CSR 2A, §7.2.b for the "COMS Summary Report" and will be submitted to the Director according to its requirements. The "Excess opacity and COM downtime report" satisfies the conditions under 45 CSR 2A, §7.2.b.3. for the "Excursion and COMS Monitoring System Performance Report". The "Excess opacity and COM downtime report" shall be submitted to the Director following the conditions outlined in 45 CSR 2A, §7.2.b.1. and §7.2.b.2.

To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

Aux. Stack (Aux ML1)

1. Applicable Standard:

   45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method:

   45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

   45 CSR 2, §8.4.a. *The owner or operator of a fuel burning unit(s) may petition for alternatives to testing, monitoring, and reporting requirements prescribed pursuant to this rule for conditions, including, but not limited to, the following:*

   45 CSR 2, §8.4.a.1. *Infrequent use of a fuel burning unit(s)*

   Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack. Based on limited operating hours, the requirement for COMS installation per Section 6.2.a of interpretive rule 45 CSR 2A was determined to be overly-burdensome and sufficient reason for the granting of alternative monitoring methods. The alternative monitoring method based on USEPA Method 9 visible emission readings is described below.

   - Primary Monitoring Method: As an alternative to COMS monitoring, a Method 9 reading will be conducted one time per month provided the following conditions are met: 1) The auxiliary boiler has operated at normal, stable load conditions for at least 24 consecutive hours and 2) weather/lighting conditions are conducive to taking proper Method 9 readings. Since the Mitchell auxiliary boiler does not utilize post-combustion particulate emissions controls, operating parameters of control equipment are nonexistent and therefore unable to be monitored.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned**

45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

The applicable paragraph for the Mitchell Plant auxiliary boilers follows:

§7.1.a.2: *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

As such, the date and time of each startup and shutdown of the auxiliary boiler will be maintained. The quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

b. **Record Maintenance**

45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. In the case of the auxiliary boilers, strip chart recordings, etc. are generally not available.

4. Exception Reporting:

Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack.

a. **Particulate Mass Emissions** – As an alternative to the testing and exception reporting requirements for particulate mass emissions from the auxiliary boiler, the following was previously proposed and approved. Based on an average heat content of approximately 139,877 Btu/gallon (calendar year 2000 data) and an AP-42 based particulate mass emissions emission factor of 2 lbs/thousand gallons, the calculated particulate mass emissions of the auxiliary boiler are 0.01 lb/mmBTU. As such, the fuel analysis records maintained under the fuel quality analysis and recordkeeping section of this plan provide sufficient evidence of compliance with the particulate mass emission limit. For the purpose of meeting exception reporting requirements, any fuel oil analysis indicating a heat content of less than 25,000 Btu per gallon will be reported to the OAQ to fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45 CSR 2 – 45 CSR 2A, §7.2.a. A heat content of 25,000 Btu/gal and a particulate emissions factor of 2 lbs/thousand gallons would result in a calculated particulate mass emissions of approximately 90% of the applicable 45 CSR 2 standard.

b. **Opacity** – As an alternative to the exception reporting requirements for opacity emissions from the auxiliary boiler, the following was previously proposed and approved. We will maintain a copy of each properly conducted (correct weather/lighting conditions, etc.) Method 9 evaluation performed. Any properly conducted Method 9 test which indicates an exceedance shall be submitted to the OAQ on a quarterly basis (within 30 days of the end of the quarter) along with an accompanying description of the excursion cause, any corrective action taken, and the beginning and ending times for the excursion.

To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

If no exceptions have occurred during the quarter, then a report will be submitted to the OAQ stating so. This will identify periods in which no method 9 tests were conducted (e.g. unit out of service) or when no fuel oil was received.

II. 45 CSR 10 Monitoring Plan:

In accordance with Section 8.2.c of 45 CSR 10, following is the proposed plan for monitoring compliance with the sulfur dioxide weight emission standards expressed in Section 3 of that rule:

A. Main Stack (1E, 2E)

1. Applicable Standard:

45 CSR 10, §3.1.b. *For fuel burning units of the Mitchell Plant of Kentucky/Wheeling Power Company, located in Air Quality Control Region I, the product of 7.5 and the total actual operating heat inputs for such units discharging through those stacks in million BTU's per hour.*

45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

A new SO_2 limit will likely be established as a result of the installation of the flue gas desulfurization system/new stack configuration and the subsequent NAAQS compliance demonstration modeling. Assuming that revised SO2 limit is more stringent than the current limit expressed in 45 CSR 10, Mitchell Plant SO_2 emissions will be regulated by the more stringent of the two limits.

2. Monitoring Method:

45 CSR 10, §8.2.c.1. *The installation, operation and maintenance of a continuous monitoring system meeting the requirements 40 CFR Part 60, Appendix B, Performance Specification 2 (PS2) or Performance Specification 7 (PS7) shall be deemed to fulfill the requirements of a monitoring plan for a fuel burning unit(s), manufacturing process source(s) or combustion source(s). CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS2.*

a. Primary Monitoring Method: The primary method of monitoring SO_2 mass emissions from the two new stack flues (located within one stack shell) will be Continuous Emissions Monitors (CEMS). Data used in evaluating the performance of the Mitchell Units with the applicable standard will be unbiased, unsubstituted data as specified in definition 45 CSR 10A, §6.1.b.1. Data capture of more than 50% constitutes sufficient data for the daily mass emissions to be considered valid. The CEMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75. Because Units 1 and 2 will discharge through separate flues and both units are "Type a" fuel burning units as defined in 45 CSR 10, the plant-wide limit is calculated by summing the limits from the two flues.

b. Other Credible Monitoring Method(s): While Mitchell Plant will use CEMS as the primary method of monitoring SO_2 mass emissions from the two flues, we are also reserving the right to use other appropriate methods that would produce credible data. These "other monitoring methods" will generally be used in the absence of CEMS data or as other credible evidence used in conjunction with CEMS data.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned:**

45 CSR 10A, §7.1.a. *Fuel burning units - The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule and the quality or quantity of fuel burned in each unit…*

45 CSR 10A, §7.1.c. *The owner or operator of a fuel burning unit or combustion source which utilizes CEMS shall be exempt from the provisions of subdivision 7.1.a. or 7.1.b, respectively.*

As such, Mitchell plant will not maintain records of the operating schedule and the quality and quantity of fuel burned in each unit for purposes of meeting the requirements for a monitoring plan under 45 CSR 10. While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

b. **Record Maintenance**

45 CSR 10A, §7.1.d. *For fuel burning units, manufacturing process sources, and combustion sources, records of all required monitoring data as established in an approved monitoring plan and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

As such, CEMS records at Mitchell Plant will be maintained for at least five years.

4. Exception Reporting:

45 CSR 10A, §7.2.a. *CEMS - Each owner or operator employing CEMS for an approved monitoring plan, shall submit a "CEMS Summary Report" and/or a "CEMS Excursion and Monitoring System Performance Report" to the Director quarterly; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the source. All reports shall be postmarked no later than forty-five (45) days following the end of each calendar quarter. The CEMS Summary Report shall contain the information and be in the format shown in Appendix A unless otherwise specified by the Director.*

45 CSR 10A, §7.2.a.1. *Submittal of 40 CFR Part 75 data in electronic data (EDR) format to the Director shall be deemed to satisfy the requirements of subdivision 7.2.a.*

As such, Mitchell Plant will submit the 40 CFR 75 quarterly electronic data reports (EDRs) to the OAQ to meet the requirements for a CEMS Summary Report and the CEMS Excursion and Monitoring System Performance Report. The EDR reports will be submitted to the OAQ no later than 45 days following the end of the quarter.

When no excursions of the 24-hour SO_2 standard have occurred, such information shall be stated in the cover letter of the EDR submittal.

B. Aux. Stack (Aux ML1)

1. Applicable Standard:

45 CSR 10, §3.1.e. *For type 'b' and Type 'c' fuel burning units, the product of 3.1 and the total* *design heat inputs for such units discharging through those stacks in million BTU's per hour.*

45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

2. Monitoring, Recordkeeping, Exception Reporting Requirements:

   45 CSR 10, §10.3. *The owner or operator of a fuel burning unit(s) which combusts natural gas, wood or distillate oil, alone or in combination, shall be exempt from the requirements of section 8.*

   As such, the Mitchell Plant auxiliary boiler (auxiliary stack) is exempt from Testing, Monitoring, Recordkeeping, and Reporting requirements found in 45 CSR 10, Section 8 because the fuel burning source combusts only distillate oil. 45 CSR 10, Section 8 also contains the requirement for the development of a monitoring plan. The simple nature of burning distillate oil results in an SO2 emission rate well below the standard.

   While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

Revisions of Monitoring Plan:

Mitchell Plant reserves the right to periodically revise the conditions of this monitoring plan. Any revised plan will become effective only after approval by the OAQ.

Implementation of Revised Monitoring Plan:

Implementation of this revised monitoring plan will occur in concurrence with the installation and operation of the new stack for Units 1 and 2 at Mitchell Plant.

SUMMARY REPORT

Pollutant	**Opacity**
Company	American Electric Power
	Philip Sporn Plant

Emmission Limitation

Regulation	Limit	Units	Period
45 CSR 2	10	%	6 minute average

Total source Operating Time 132,361 minutes

Reporting Period: Calendar Quarter	10/1/00	to	12/31/00
Monitor Manufacturer :	United Sciences, Inc.		
Model Number:	500C		
Date of last Certification or Audit:	11/28/00		
Process Unit(s) Description:	Units 1-4 Stack,		

Four coal fired power generation units attached to a common stack (CS014).

Emissions Data Summary

1. Duration of excess emissions in reporting period due to:

	45 CSR 2
a. Startup / Shutdown	1206 minutes
b. Soot Blowing	0 minutes
c. Malfunction due to Control Equipment Problems	96 minutes
d. Malfunction due to Process Problem	12 minutes
e. Other Known Causes	0 minutes
f. Unknown Causes	0 minutes
2. Total Duration	1314 minutes
3. Percent Excess Emission	0.99 %

% Excess = 100 * (Total Duration / Total Source Operating Time)

COMS Performance Summary

1. COMS Downtime in reporting period due to:

a. Monitor Equipment Malfunction	66 minutes
b. Other Equipment Malfunction	0 minutes
c. Quality Assurance Calibration	1170 minutes
d. Other Known Causes	0 minutes
e. Unknown Causes	0 minutes
2. Total COMS Downtime	1236 minutes
3. Percent COMS Downtime	0.93 %

% Downtime = 100 * (Total COMS Downtime / Total Source Operating Time)

Please Note:

1. Separate Summary Reports are required for each boiler in the system when it has separate monitoring equipment.
2. Total source operating time means the total time which affected source is operating, including all periods of start-up, shut-down, malfunction, soot blowing, or COMS downtime as those terms are defined under the rule.
3. All times for opacity must be reported in minutes.
4. On a separate page describe any changes since the last reporting period to the COMS process or controls.
5. Other reports may be necessary to meet requirements.

Appendix A
Sample

EXCESS OPACITY AND COM DOWNTIME REPORT

Page: 1

Facility Name: PHILIP SPORN
Address: P.O. BOX 389
New Haven, WVa 25265

Report Period: 10/01/00 to 12/31/00
Emission Limit: 10.499

Stack/Unit ID: CS014

Parameter Name: OPACSQA

Appendix B
Sample

Date	Start Time	End Time	Duration (Minutes)	Average Opacity	Maximum Opacity	Causes/ Corrective Action
10/01/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/02/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/03/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/04/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/05/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/06/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/07/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/08/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/09/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/10/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/10/00	0606	0618	12	11	11	TR Set Trip Reset TR
10/10/00	0636	0642	6	11	11	TR Set Trip Reset TR
10/10/00	0824	0836	12	11	11	TR Set Trip Reset TR
10/11/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/11/00	1130	1224	54	-	-	COM Repair, COM o/s COM Lens Cleaned
10/12/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/13/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/14/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/15/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/16/00	0106	0118	12	-	-	Monitor Calibration/QA, COM o/s Completed COM Calibration/QA Activity
10/16/00	1448	1454	6	15	15	Unit Tripped None

* = Time period does not end during selected time range

APPENDIX B

Certification of Data Accuracy

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 and 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 USEPA); or

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

APPENDIX C

DAQ letter dated September 3, 2002 regarding Thermal Decomposition of Boiler Cleaning Solution

Division of Air Quality
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943
Telephone Number: (304) 926-3647
Fax Number: (304) 926-3739

West Virginia Department of Environmental Protection

Bob Wise
Governor

Michael O. Callaghan
Cabinet Secretary

Mr. Greg Wooten
Senior Engineer
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373

September 3, 2002

Dear Mr. Wooten:

RE: Thermal Decomposition of Boiler Cleaning Solution at AEP Facilities (i.e. Kammer, Mitchell, Mountaineer, Philip Sporn, Amos or Kanawha River Plants)

Based on the information you provided by email dated August 19, 2002, subsequent phone conversations, and email dated September 3, 2002, (copies attached) the Division is granting approval for AEP to thermally decompose boiler cleaning solution in the boilers at the AEP facilities identified above.

The DAQ is granting approval for AEP to thermally decompose boiler cleaning solution at the AEP facilities identified above, on an as needed and pre-approved basis, subject to the DAQ notification requirements, as outlined in the attached document titled "American Electric Power Boiler Chemical Cleaning Process Evaporation Notification Procedure", as revised.

If you have any questions regarding this matter please contact Laura Mae Crowder of my staff at (304) 926-3647.

Sincerely,

Jesse D. Adkins
Assistant Director of Enforcement
Division of Air Quality

cc: file

West Virginia Department of Environmental Protection

"Promoting a healthy environment."

AMERICAN ELECTRIC POWER
BOILER CHEMICAL CLEANING PROCESS
EVAPORATION NOTIFICATION PROCEDURE

Step 1. The spent boiler chemical cleaning process liquid will be collected and stored on site in temporary (frac) tanks and/or permanently installed Metal Cleaning storage tanks. One sample will be collected for laboratory analysis from each storage tank, unless the tanks were manifolded together such that a number of tanks were filled simultaneously, resulting in the co-mingling of the solution in those tanks; in which case, one representative sample may be collected from each group of tanks that were manifolded together. The analyses from the tanks will be used to determine the hazard characteristics of the total volume of material.

Step 2. Upon receipt and assessment of the laboratory TCLP analyses, the hazard characteristics of the spent cleaning solution will be determined. Upon being confirmed non-hazardous, the "AEP facility" (i.e. Kammer, Mitchell, Mountaineer, Philip Sporn, Amos, or Kanawha River Plant) will proceed with the process to thermally decompose (evaporate) the spent material in a boiler on site.

Step 3. The AEP facility will notify West Virginia DAQ by telephone, facsimile or email on or before the day of scheduled commencement for the evaporation of the non-hazardous spent cleaning solution. AEP will submit via facsimile to the Compliance and Enforcement Section of the DAQ, a minimum of one (1) business day prior to commencement of the thermal decomposition process, the following information:

- The results of the laboratory TCLP analyses
- The volume of spent cleaning solution to be evaporated
- The designated boiler(s) in which the spent cleaning solution will be evaporated
- The expected schedule for completing the process

Step 4. AEP will perform evaporation of the spent cleaning solution in the designated boiler(s) in accordance with the appropriate chemical cleaning process document (e.g. "Kammer/Mitchell Plant Chemical Cleaning Process") and this notification procedure.

APPENDIX D

DAQ letter dated January 21, 2004 regarding Demineralizer Resin Burn

Division of Air Quality
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943
Telephone Number: (304) 926-3647
Fax Number: (304) 926-3739

West Virginia Department of Environmental Protection

Bob Wise
Governor

Stephanie R. Timmermeyer
Cabinet Secretary

Mr. Frank Blake
Engineer – Environmental Services
American Electric Power
1 Riverside Plaza – Floor 22
Columbus, Ohio 43215-2373

January 21, 2004

Dear Mr. Blake:

RE: Demineralizer Resin Burn at AEP Facilities (i.e. John Amos, Kammer, Mitchell, Mountaineer, Philip Sporn, or Kanawha River Plants)

Based on the information you provided during phone conversations on November 14, 2003 as well as by paper mail on November 25, 2003, the Division of Air Quality (DAQ) is granting approval for AEP to burn demineralizer resin in the boilers at the AEP facilities identified above.

The DAQ is granting approval for AEP burn demineralizer resin at the AEP facilities identified above on an as needed and pre-approved basis, subject to the DAQ notification requirements, as outlined in the document titled "American Electric Power Demineralizer Resin Burn Notification Procedure" as revised.

If you have any questions regarding this matter please contact Michael Rowe of my staff at (304) 926-3647.

Sincerely,

Jesse D. Adkins
Assistant Director of Enforcement
Division of Air Quality

cc: file
M. Dorsey, DWWM

West Virginia Department of Environmental Protection "Promoting a healthy environment."

AMERICAN ELECTRIC POWER DEMINERALIZER RESIN BURN NOTIFICATION PROCEDURE

Step 1. An appropriate number of samples representative of the used demineralizer resin to be consumed in the boiler will be collected for laboratory analysis to determine the hazard characteristics of the total volume of the material. Analysis will be completed using ASTM approved methods and by a WV Department of Environmental Protection certified laboratory.

Step 2. Upon receipt and assessment of the laboratory TCLP analysis, the hazard characteristics of the used demineralizer resin will be determined. Upon being confirmed as non-hazardous, the AEP facility will proceed to notify the West Virginia DAQ of the intent to burn the demineralizer resin. If the material is determined to be hazardous, it must be disposed of in accordance with 33CSR20 “Hazardous Waste Management Rule”. Questions concerning this rule should be directed to the Division of Water and Waste Management (DWWM) at 304 558-5989.

Step 3. The AEP facility will notify the West Virginia DAQ by telephone, facsimile or email at least one business day before the scheduled commencement for the burn of the non-hazardous demineralizer resin. AEP will submit via facsimile to the Compliance and Enforcement Section of the DAQ, a minimum of one (1) business day prior to commencement of the demineralizer resin burn, the following information:

- The results of the laboratory TCLP analyses
- The volume and/or amount of demineralizer resin to be burned
- The designated boiler(s) in which the demineralizer resin will be burned.
- The expected schedule with beginning and end dates and times for completing the process
- The notification will be formatted with a subject line clearly defining the purpose of the notification and the facility where the resin will be burned.

Step 4. AEP will perform the demineralizer resin burn in the designated boiler(s) in accordance with the submitted notification. AEP will maintain records on site of all demineralizer resin burned. These records will include the date, time, boiler, load condition, volume/amount of resin and TCLP analysis.

APPENDIX E

Cross-State Air Pollution Rule (CSAPR) Requirements

Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements

Plant Name: **Mitchell Plant**	West Virginia ID Number: **051-00005**	ORIS/Facility Code: **3948**

1. Owners and operators of the CSAPR subject unit(s) identified in the CSAPR Monitoring Requirements Table below are subject to the requirements of the *CSAPR NO_X Annual Trading Program Requirements, CSAPR NO_X Ozone Season Group 2 Trading Program Requirements, and the CSAPR SO_2 Group 1 Trading Program Requirements* in Appendix A to this permit.

2. Owners and operators of the CSAPR subject unit(s) identified in the CSAPR Monitoring Requirements Table below are subject to the monitoring requirements specified in the table below.

CSAPR MONITORING REQUIREMENTS TABLE			
Description of Monitoring Requirements:	**Parameter**		
Unit ID: Unit 1, Unit 2	**SO_2**	**NO_X**	**Heat Input**
Continuous emission monitoring system (CEMS) pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	X	X	X
Excepted monitoring system pursuant to 40 CFR part 75, appendix D (*Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units*)			
Excepted monitoring system pursuant to 40 CFR part 75, appendix E (*Optional NO_X Emissions Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units*)			
Low Mass Emissions excepted monitoring (LME) pursuant to 40 CFR 75.19 (*Optional SO_2, NO_X, and CO_2 Emissions Calculation for Low Mass Emissions (LME) Units*)			
EPA-approved alternative monitoring system pursuant to 40 CFR part 75, subpart E			

3. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435, (*CSAPR NO_X Annual Trading Program),* 97.830 through 97.835 *(CSAPR NO_X Ozone Season Group 2 Trading Program) and,* 97.630 through 97.635 *(CSAPR SO_2 Group 1 Trading Program)*. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading program.

4. Owners and operators shall submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable.

5. Owners and operators that want to use an alternative monitoring system shall submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E, 40 CFR 75.66, and the applicable trading program provisions found in 40 CFR *97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program) and, 97.635 (CSAPR SO_2 Group 1 Trading Program)*. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at https://www.epa.gov/airmarkets/complete-list-responses-40-cfr-part-75-petitions.

6. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR *97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program) and/or, 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program)* shall submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and *97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program) and/or 97.635 (CSAPR SO_2 Group 1 Trading Program)*. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at https://www.epa.gov/airmarkets/complete-list-responses-40-cfr-part-75-petitions.

CSAPR NO_X Annual Trading Program requirements (40 CFR 97.406)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general monitoring, recordkeeping, and reporting requirements, including: installation, certification, and data accounting; compliance deadlines; reporting data; prohibitions; and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including: monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Annual emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source exceed the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) CSAPR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for West Virginia and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying:

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in West Virginia for such control period, by which each common designated representative's share of such

NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in West Virginia during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of CSAPR NO_X Annual allowances held for compliance.

(i). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A CSAPR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart AAAAA, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) Owners and operators shall not be required to revise the title V permit for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA.

(2) Owners and operators shall revise the title V permit for any addition of, or change to, a unit's description in the

CSAPR Monitoring Requirements Table above. The addition of, or change to, a unit's description of whether a unit is required to monitor and report NOx emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.430 through 97.435 is eligible for minor permit modification procedures in accordance with 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.

(2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR NO_X Ozone Season Group 2 Trading Program Requirements (40 CFR 97.806)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general monitoring, recordkeeping, and reporting requirements, including: installation, certification, and data accounting; compliance deadlines; reporting data; prohibitions; and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including: monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Ozone Season Group 2 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source exceed the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NO_X Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and

(B). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(2) CSAPR NO_X Ozone Season Group 2 assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for West Virginia and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X

emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in West Virginia for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Ozone Season Group 2 Trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart EEEEE or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in West Virginia during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(ii). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(4) Vintage of CSAPR NO_X Ozone Season Group 2 allowances held for compliance.

(i). A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart EEEEE.

(6) Limited authorization. A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and (ii). Notwithstanding any other provision of 40 CFR part 97, subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) Owners and operators shall not be required to revise the title V permit for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart EEEEE.

(2) Owners and operators shall revise the title V permit for any addition of, or change to, a unit's description in the CSAPR Monitoring Requirements Table above. The addition of, or change to, a unit's description of whether a unit is required to monitor and report NOx emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.830 through 97.835 is eligible for minor permit modification procedures in accordance with 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart EEEEE.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR SO_2 Group 1 Trading Program requirements (40 CFR §97.606)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general monitoring, recordkeeping, and reporting requirements, including: installation, certification, and data accounting; compliance deadlines; reporting data; prohibitions; and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including: monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) CSAPR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source exceed the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) CSAPR SO_2 Group 1 assurance provisions.

(i). If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for West Virginia and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in West Virginia for such control period, by which each common designated representative's share of such SO_2

emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in West Virginia during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of CSAPR SO_2 Group 1 allowances held for compliance.

(i). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) Owners and operators shall not be required to revise the title V permit for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) Owners and operators shall revise the title V permit for any addition of, or change to, a unit's description in the

CSAPR Monitoring Requirements Table above. The addition of, or change to, a unit's description of whether a unit is required to monitor and report NOx emissions using a continuous emission monitoring system (under subpart B of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.630 through 97.635 is eligible for minor permit modification procedures in accordance with 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

APPENDIX F

Acid Rain Permit

west virginia department of environmental protection
Division of Air Quality

Phase II Acid Rain Permit

Plant Name: **Mitchell Power Station**		Permit #: **R33-3948-2027-6**
Affected Unit(s): **1, 2**		
Operator: **Kentucky Power Company**		ORIS Code: **3948**
Effective Date	From: **January 1, 2023**	To: **December 31, 2027**

Contents:

1. Statement of Basis.
2. SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.
3. Comments, notes and justifications regarding permit decisions and changes made to permit application forms during the review process, and any additional requirements or conditions.
4. The permit application forms submitted for this source, as corrected by the West Virginia Division of Air Quality. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

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1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with W. Va. Code §22-5-4(a)(16) and Titles IV and V of the Clean Air Act, the West Virginia Department of Environmental Protection, Division of Air Quality issues this permit pursuant to 45CSR33 and 45CSR30.

Permit Approval

Laura M. Crowder Digitally signed by: Laura M. Crowder DN: CN = Laura M. Crowder email = Laura.M.Crowder@wv.gov C = US O = West Virginia Department of Environmental Protection OU = Division of Air Quality Date: 2022.12.19 12:21:39 -05'00'

Laura M. Crowder, Director
Division of Air Quality

December 19, 2022
Date

West Virginia Department of Environmental Protection • Division of Air Quality

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No. **1**

SO_2 Allowances	**Year**				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	18995	18995	18995	18995	18995
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A
The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).					

NO_X Requirements	**2023**	**2024**	**2025**	**2026**	**2027**
NO_X Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50

Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers.

In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

West Virginia Department of Environmental Protection • Division of Air Quality

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No. **2**

SO_2 Allowances	**Year**				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	19656	19656	19656	19656	19656
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A
The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).					

NO_x Requirements	**2023**	**2024**	**2025**	**2026**	**2027**
NO_x Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50

Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers.

In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/31/2021

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☑ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Mitchell (WV)	West Virginia	3948

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Mitchell (WV)
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
  (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
  (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
  (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

Acid Rain - Page 4

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Scott A. Weaver

Signature Scott A Weaver

Date 4/7/2022

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

Page 1

This submission is: ☐ New ☑ Revised

Page 1 of 2

STEP 1
Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

Plant Name	State	Plant Code
Mitchell	WV	3948

STEP 2

Identify each affected Group 1 and Group 2 boiler using the unit IDs from the current Certificate of Representation covering the facility. Also indicate the boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom, and select the compliance option for each unit by making an 'X' in the appropriate row and column.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	X	X				
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)						
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)						
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)						
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						

EPA Form 7610-28 (Revised 7-2014)

NOx Compliance – Page 2

STEP 2, cont'd

Plant Name (From Step 1)	Mitchell

	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(i) NO_x Averaging Plan (include NO_x Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form))						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						

STEP 3: Identify the first calendar year in which this plan will apply.

January 1, 2019

STEP 4: Read the special provisions and certification, enter the name of the designated representative, sign and date.

Special Provisions

General. This source is subject to the standard requirements in 40 CFR 72.9. These requirements are listed in this source's Acid Rain Permit.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Scott A. Weaver	
Signature	Scott A Weaver	Date 12-18-18

EPA Form 7610-28 (Revised 7-2014)

APPENDIX G

Class II General Permit Registration
G60-C057A

West Virginia Department of Environmental Protection

Joe Manchin, III
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Class II General Permit
G60-C Registration to Modify

for the
Prevention and Control of Air Pollution in regard to the
Construction, Modification, Relocation, Administrative Update and
Operation of Emergency Generators

The permittee identified at the facility listed below is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of General Permit G60-C.

G60-C057A

Issued to:

AEP Generation Resources Inc.
Mitchell Plant
051-00005

William F. Durham
Director

Issued: August 8, 2014

This Class II General Permit Registration will supercede and replace G60-C057.

Facility Location:	State Route 2, Moundsville, Marshall County, West Virginia
Mailing Address:	P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generation Facility
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Registration Type:	Modification
Description of Change:	Installation of two additional generators (EG-1 and EG-2) to black start the facility.

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 or registration 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.

Unless otherwise stated WVDEP DAQ did not determine whether the permittee is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart ZZZZ.

All registered facilities under Class II General Permit G60-C are subject to Sections 1.0, 2.0, 3.0, and 4.0.

The following sections of Class II General Permit G60-C apply to the registrant:

Section 5	Reciprocating Internal Combustion Engines (R.I.C.E.)	X
Section 6	Tanks	X
Section 7	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40CFR60 Subpart IIII)	X
Section 8	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (40CFR60 Subpart JJJJ)	X

Emission Units

Emission Unit ID	Emission Unit Description (Make, Model, Serial No.)	Year Installed	Design Capacity (Bhp/rpm)
LPG	Generac SG080, 127 BHP Engine (Spark Ignition Engine)	2013	127/1,800
EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	2014	3,717/1,800
EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	2014	3,004/1,800

Emission Limitations

Source ID#	Nitrogen Oxides		Carbon Monoxide		Volatile Organic Compounds	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
LPG	0.74	0.19	21.75	5.44	0.22	0.06
EG-1	59.9	14.98	7.66	1.92	0.94	0.24
EG-2	36.4	9.1	4.85	1.21	1.18	0.03
TOTAL	97.04	24.27	34.26	8.57	2.34	0.33

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Wheeling Power transfer

1 message

G M Palmer <gmpalmer@aep.com> Thu, Mar 20, 2025 at 11:54 AM
To: "Daniel.P.Roberts@wv.gov" <Daniel.P.Roberts@wv.gov>
Cc: Brandon T Belcher <btbelcher@aep.com>

Email info below.

G M Palmer

From: Gregory J Wooten
Sent: Tuesday, September 6, 2022 8:33 PM
To: Douglas J Rosenberger
Cc: Todd A March; Jeffrey D Clark; G M Palmer
Subject: FW: Mitchell Transfer from Kentucky to Wheeling Power Company

Doug,
After a recent discussion with WVDEP, it became unnecessary to transfer the Title V Permit and the Class II General Air Permit.

Last week, I spoke with the WVDEP Air Director (Laura Crowder) about the Mitchell Permit transfers from Kentucky Power to Wheeling Power. Laura had also spoken with the WVDEP legal department just to confirm that her position was correct.

She indicated that in this situation, there is no need to transfer the air permits. She explained that under the air regulations, WVDEP has the option to issue the permits either in the name of the owner or the operator. Because Kentucky Power will still be one of the owners (until the liberty transfer), there is no need to transfer the permits out of Kentucky Power. She mentioned that if the Designated Representative (Scott Weaver) or the plant responsible official (plant manager) was changing, then those changes would need to be made. Since neither are changing, there is nothing to change.

She did indicate that we will need to submit a request for ownership transfer when the Kentucky power portion is transferred to Liberty. Laura said they have records of the fee we paid for the original transfer request, so there will be no need to pay an additional fee when the ownership transfer occurs.

Greg

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY
GREGORY J WOOTEN | ENVIRONMENTAL ENGINEER STAFF
GJWOOTEN@AEP.COM | A:8.200.1262
1 RIVERSIDE PLAZA, COLUMBUS, OH 43215

Thanks,

AMERICAN ELECTRIC POWER

G M PALMER | **ENVIRONMENTAL COORD PRIN**
GMPALMER@AEP.COM | D:304.843.6048 | C:304.559.4538
8999 ENERGY ROAD, MOUNDSVILLE, WV 26041

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Fwd: Permits Transfer Kentucky Power Company to Wheeling Power Company

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Thu, Mar 20, 2025 at 10:05 AM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

---------- Forwarded message ---------
From: **Crowder, Laura M** <laura.m.crowder@wv.gov>
Date: Wed, Mar 19, 2025 at 1:48 PM
Subject: Re: Permits Transfer Kentucky Power Company to Wheeling Power Company
To: Roberts, Daniel P <daniel.p.roberts@wv.gov>
Cc: Grose, Megan E <megan.e.grose@wv.gov>, McCumbers, Carrie <Carrie.McCumbers@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>

In my personal records, I do not show that I ever signed it. But, I may have forgotten to make a note of it.

On Wed, Mar 19, 2025 at 12:39 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Has the name change from Kentucky to Wheeling Power Company been approved? I was checking because AirTrax still lists Kentucky Power Company.
>
> Dan
>
> On Tue, Aug 8, 2023 at 2:43 PM Grose, Megan E <megan.e.grose@wv.gov> wrote:
>
>> No. You did not sign this one. This is the one I mentioned to you last week or week before last.
>>
>> Megan E. Grose
>>
>> Environmental Resource Analyst
>>
>> WV DEP Division of Air Quality
>>
>> 601 57th Street S.E.
>> Charleston, WV 25304
>> 304-926-0499 ext. 43810
>> megan.e.grose@wv.gov
>>
>> On Tue, Aug 8, 2023 at 2:39 PM Crowder, Laura M <laura.m.crowder@wv.gov> wrote:
>>
>>> Megan,
>>>
>>> Was this ever finalized?
>>>
>>> Laura
>>>
>>> ---------- Forwarded message ---------
>>> From: **Grose, Megan E** <megan.e.grose@wv.gov>
>>> Date: Mon, Aug 29, 2022 at 11:00 AM
>>> Subject: Permits Transfer Kentucky Power Company to Wheeling Power Company
>>> To: Laura M Crowder <laura.m.crowder@wv.gov>
>>>
>>> Laura

Attached is the supporting documentation and two letters to be signed for permit transfers from Kentucky Power Company to Wheeling Power Company for the Mitchell Plant. The fee was paid January 28 but the transfer was held awaiting a PSC approval. If you have any questions or see anything that needs to be corrected please let me know.

Megan E. Grose

Environmental Resource Analyst

WV DEP Division of Air Quality

601 57th Street S.E.
Charleston, WV 25304
304-926-0499 ext. 43810
megan.e.grose@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Fwd: Permits Transfer Kentucky Power Company to Wheeling Power Company

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Thu, Mar 20, 2025 at 10:04 AM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

---------- Forwarded message ---------
From: **Mink, Stephanie R** <stephanie.r.mink@wv.gov>
Date: Thu, Mar 20, 2025 at 9:26 AM
Subject: Re: Permits Transfer Kentucky Power Company to Wheeling Power Company
To: Grose, Megan E <megan.e.grose@wv.gov>
Cc: Scott, Kimberly A <kimberly.a.scott@wv.gov>, Daniel P Roberts <daniel.p.roberts@wv.gov>

It sounds like the PSC probably didn't approve it or one of us would have already updated Airtrax.

Thanks

On Thu, Mar 20, 2025 at 9:16 AM Grose, Megan E <megan.e.grose@wv.gov> wrote:

> I remember now that when I started the transfer Laura told me to wait because of the PSC decision. I never heard back from the companies involved.
>
> Megan Grose
> Environmental Resources Analyst
> WV Department of Environmental Protection
> Division of Air Quality
> 601 57th Street SE
> Charleston, WV 25304
> 304-926-0499 x43810
>
> On Thu, Mar 20, 2025 at 9:12 AM Mink, Stephanie R <stephanie.r.mink@wv.gov> wrote:
>
>> Kim,
>>
>> That information is from when I handed their information off to Megan. If nothing further ever happened then I am assuming they are still operating under the same name. Laura looked back at her signed letters and did not see where anything was ever signed by her.
>>
>> Dan,
>>
>> My only other suggestion is that you check with Greg Wooten to see if he has any information indicating that the name change went through. If not we can proceed under the old name and process a change after the permit gets signed if needed. It was all very confusing since they were talking about keeping partial ownership but changing names and had to have approval to do so by the PSC.
>>
>> Thanks
>> Stephanie
>>
>> On Thu, Mar 20, 2025 at 8:55 AM Scott, Kimberly A <kimberly.a.scott@wv.gov> wrote:
>>
>>> Dan,
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>>> The only information I have is an email from 2022 between the customer and Stephanie (attached). I'm not sure if paperwork was submitted or not because it's not in the electronic file we have for permit transfers.
>>>
>>> Stephanie,

If you have the paperwork can you please forward it to me?

Kim

On Wed, Mar 19, 2025 at 12:49 PM Mink, Stephanie R <stephanie.r.mink@wv.gov> wrote:

Dan didn't include you on this so I'm passing it along to see if you have any updates.

Thanks
Stephanie

---------- Forwarded message ---------
From: **Roberts, Daniel P** <daniel.p.roberts@wv.gov>
Date: Wed, Mar 19, 2025 at 12:39 PM
Subject: Re: Permits Transfer Kentucky Power Company to Wheeling Power Company
To: Grose, Megan E <megan.e.grose@wv.gov>
Cc: Crowder, Laura M <laura.m.crowder@wv.gov>, McCumbers, Carrie <Carrie.McCumbers@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>

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Dan

On Tue, Aug 8, 2023 at 2:43 PM Grose, Megan E <megan.e.grose@wv.gov> wrote:

No. You did not sign this one. This is the one I mentioned to you last week or week before last.

Megan E. Grose

Environmental Resource Analyst

WV DEP Division of Air Quality

601 57th Street S.E.
Charleston, WV 25304
304-926-0499 ext. 43810
megan.e.grose@wv.gov

On Tue, Aug 8, 2023 at 2:39 PM Crowder, Laura M <laura.m.crowder@wv.gov> wrote:

Megan,

Was this ever finalized?

Laura

---------- Forwarded message ---------
From: **Grose, Megan E** <megan.e.grose@wv.gov>
Date: Mon, Aug 29, 2022 at 11:00 AM
Subject: Permits Transfer Kentucky Power Company to Wheeling Power Company
To: Laura M Crowder <laura.m.crowder@wv.gov>

Laura

Attached is the supporting documentation and two letters to be signed for permit transfers from Kentucky Power Company to Wheeling Power Company for the Mitchell Plant. The fee was paid January 28 but the transfer was held awaiting a PSC approval. If you have any questions or see anything that needs to be corrected please let me know.

Megan E. Grose

Environmental Resource Analyst

WV DEP Division of Air Quality

601 57th Street S.E.
Charleston, WV 25304
304-926-0499 ext. 43810
megan.e.grose@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Permits Transfer Kentucky Power Company to Wheeling Power Company

1 message

Mink, Stephanie R <stephanie.r.mink@wv.gov> Thu, Mar 20, 2025 at 9:25 AM
To: "Grose, Megan E" <megan.e.grose@wv.gov>
Cc: "Scott, Kimberly A" <kimberly.a.scott@wv.gov>, Daniel P Roberts <daniel.p.roberts@wv.gov>

It sounds like the PSC probably didn't approve it or one of us would have already updated Airtrax.

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> 601 57th Street SE
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>>>> Thanks

Stephanie

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From: **Roberts, Daniel P** <daniel.p.roberts@wv.gov>
Date: Wed, Mar 19, 2025 at 12:39 PM
Subject: Re: Permits Transfer Kentucky Power Company to Wheeling Power Company
To: Grose, Megan E <megan.e.grose@wv.gov>
Cc: Crowder, Laura M <laura.m.crowder@wv.gov>, McCumbers, Carrie <Carrie.McCumbers@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>

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>> Charleston, WV 25304
>> 304-926-0499 ext. 43810

megan.e.grose@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Permits Transfer Kentucky Power Company to Wheeling Power Company

1 message

Grose, Megan E <megan.e.grose@wv.gov> Thu, Mar 20, 2025 at 9:15 AM
To: "Mink, Stephanie R" <stephanie.r.mink@wv.gov>
Cc: "Scott, Kimberly A" <kimberly.a.scott@wv.gov>, Daniel P Roberts <daniel.p.roberts@wv.gov>

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Environmental Resources Analyst
WV Department of Environmental Protection
Division of Air Quality
601 57th Street SE
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To: Grose, Megan E <megan.e.grose@wv.gov>
Cc: Crowder, Laura M <laura.m.crowder@wv.gov>, McCumbers, Carrie <Carrie.McCumbers@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>

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> Environmental Resource Analyst
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> 304-926-0499 ext. 43810
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>> Charleston, WV 25304
>> 304-926-0499 ext. 43810
>> megan.e.grose@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Kentucky Power proof

1 message

Mink, Stephanie R <stephanie.r.mink@wv.gov> Wed, Mar 19, 2025 at 2:18 PM
To: "Roberts, Daniel P" <daniel.p.roberts@wv.gov>

Thanks a bunch, we'll work it out tomorrow.

On Wed, Mar 19, 2025 at 2:09 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Everything looks good in the proof. I'll touch base with you as soon as I hear anything one way or the other on the name.
>
> Thanks!
> Dan
>
> On Wed, Mar 19, 2025 at 1:31 PM Mink, Stephanie R <stephanie.r.mink@wv.gov> wrote:
>
>> I have confirmed space for Monday, 3/24. Please review the proof and let me know if everything appears correct. If we need to make changes we need to get them in ASAP tomorrow to guarantee that this is published on time.
>>
>> Thanks
>> Stephanie
>>
>> --
>>

>> Stephanie Mink
>>
>> Environmental Resources Associate
>>
>> West Virginia Department of Environmental Protection
>>
>> Division of Air Quality, Title V & NSR Permitting
>>
>> 601 57th Street SE
>>
>> Charleston, WV 25304
>>
>> Phone: 304-926-0499 x41281

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Permits Transfer Kentucky Power Company to Wheeling Power Company

1 message

Crowder, Laura M <laura.m.crowder@wv.gov> Wed, Mar 19, 2025 at 1:48 PM
To: "Roberts, Daniel P" <daniel.p.roberts@wv.gov>
Cc: "Grose, Megan E" <megan.e.grose@wv.gov>, "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>

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>>> Laura
>>>
>>> Attached is the supporting documentation and two letters to be signed for permit transfers from Kentucky Power Company to Wheeling Power Company for the Mitchell Plant. The fee was paid January 28 but the transfer was held awaiting a PSC approval. If you have any questions or see anything that needs to be corrected please let me know.
>>>
>>> Megan E. Grose
>>>
>>> Environmental Resource Analyst

WV DEP Division of Air Quality

601 57th Street S.E.
Charleston, WV 25304
304-926-0499 ext. 43810
megan.e.grose@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Notice for Kentucky Power Company - Mitchell Plant - R30-05100005-2025 renewal

1 message

McCumbers, Carrie <carrie.mccumbers@wv.gov> Wed, Mar 19, 2025 at 1:38 PM
To: "Roberts, Daniel P" <daniel.p.roberts@wv.gov>
Cc: Stephanie R Mink <stephanie.r.mink@wv.gov>

The notice looks good to me.

Thanks,
Carrie

On Wed, Mar 19, 2025 at 1:09 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Here is the Notice for publication in *The Intelligencer* on Monday March 24, 2025.
>
> Thanks,
> Dan

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Kentucky Power proof

1 message

Mink, Stephanie R <stephanie.r.mink@wv.gov> Wed, Mar 19, 2025 at 1:30 PM
To: Daniel P Roberts <daniel.p.roberts@wv.gov>

I have confirmed space for Monday, 3/24. Please review the proof and let me know if everything appears correct. If we need to make changes we need to get them in ASAP tomorrow to guarantee that this is published on time.

Thanks
Stephanie

--

Stephanie Mink

Environmental Resources Associate

West Virginia Department of Environmental Protection

Division of Air Quality, Title V & NSR Permitting

601 57th Street SE

Charleston, WV 25304

Phone: 304-926-0499 x41281

Intelligencer - Kentucky Power proof.pdf
222K

INTERIM AD DRAFT

This is the proof of your ad scheduled to run in **The Intelligencer** on the dates indicated below. If changes are needed, please contact us prior to deadline at **(304) 233-0100**.

Notice ID: n3nfAYmW5LYNmum4jAXP | **Proof Updated: Mar. 19, 2025 at 01:21pm EDT**
Notice Name: Kentucky Power renewal

See Proof on Next Page

This is not an invoice. Below is an estimated price, and it is subject to change. You will receive an invoice with the final price upon invoice creation by the publisher.

FILER	FILING FOR
Stephanie Mink stephanie.r.mink@wv.gov (304) 926-0499	The Intelligencer

Columns Wide: 1
Total Column Inches: 14.09
Number of Lines: 145

Ad Class: Legals

03/24/2025: Other	67.65
Affidavit Fee	10.00

Subtotal	$77.65
Tax	$0.00
Processing Fee	$7.77
Total	**$85.42**

NOTICE OF COMMENT PERIOD FOR DRAFT/ PROPOSED OPERATING PERMIT RENEWAL

Title V of the Federal Clean Air Act and the state Air Pollution Control Act requires that all major sources and certain minor sources have a permit to operate which states all requirements (e.g. emission limitations, monitoring requirements, etc.) established by regulations promulgated under the aforementioned programs. The Division of Air Quality (DAQ) has determined that the draft/proposed permit renewal referenced herein meets this requirement.

The DAQ is providing notice to the general public of its preliminary determination to issue an operating permit renewal to the following company for operation of the referenced fossil fuel fired electric generation facility:

Kentucky Power Company
Mitchell Plant
Plant ID No.: 051-00005
8999 Energy Road
Moundsville, WV 26041

This notice solicits comments from the public and affected state(s) concerning the above preliminary determination and provides an opportunity for such parties to review the basis for the proposed approval and the "draft" permit renewal. This notice also solicits comments from the U.S. EPA concerning the same preliminary determination and provides an opportunity for the U.S. EPA to concurrently review the basis for the proposed approval as a “proposed” permit.

All written comments submitted by the public and affected state(s) pursuant to this notice must be received by the DAQ within thirty (30) days of the date of publication of this notice. Under concurrent review, written comments submitted by the U.S. EPA must be received by the DAQ within forty-five (45) days from the date of publication of this notice or from the date the U.S. EPA receives this draft/proposed permit renewal, whichever is later. In the event the 30th/45th day is a Saturday, Sunday, or legal holiday, the comment period will be extended until 5:00 p.m. on the following regularly scheduled business day. The public shall have 135 days from the date of publication of this notice to file petitions for concurrently reviewed permits. Upon notice by the U.S. EPA to the DAQ, prior to the end of the 45 day notice period, the U.S. EPA may choose to hold the 30 day comment period on the draft permit and the 45 day comment period on the proposed permit sequentially. During the public comment period any interested person may submit written comments on the draft permit and, if no public hearing has been scheduled, may request a public hearing. A request for a public hearing shall be in writing and shall state the nature of the issues proposed to be raised in the hearing. The Director of the DAQ shall grant such a request for a hearing if she concludes that a public hearing is appropriate. Any public hearing shall be held in the general area in which the facility is located, after 30 day notice is given. The DAQ will consider all written comments prior to final action on the permit.

Copies of the Permit Application, DAQ Fact Sheet, and Draft/Proposed Permit Renewal may be downloaded from the DAQ's web site at: https://dep.wv.gov/daq/permitting/titlevpermits/Pages/default.aspx.

Comments and questions concerning this matter should be addressed to:

WV Department of Environmental Protection
Division of Air Quality
601 57th Street SE
Charleston, WV 25304
Contact: Dan Roberts
(304) 926-0499 ext.: 41902
Daniel.p.roberts@wv.gov
Int. Mar 24, 2025

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Notice for Kentucky Power Company - Mitchell Plant - R30-05100005-2025 renewal

1 message

Mink, Stephanie R <stephanie.r.mink@wv.gov> Wed, Mar 19, 2025 at 1:11 PM
To: "Roberts, Daniel P" <daniel.p.roberts@wv.gov>
Cc: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

Thanks Dan! If you could please get the drafts to me by the end of the day tomorrow I would appreciate it. I'm only working half a day on Friday and will need to get everything ready to go to the webmaster & EPA before this publishes on Monday.

On Wed, Mar 19, 2025 at 1:09 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Here is the Notice for publication in *The Intelligencer* on Monday March 24, 2025.
>
> Thanks,
> Dan

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Notice for Kentucky Power Company - Mitchell Plant - R30-05100005-2025 renewal

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Wed, Mar 19, 2025 at 1:09 PM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>

Here is the Notice for publication in *The Intelligencer* on Monday March 24, 2025.

Thanks,
Dan

concurrent notice for renewal R30-05100005-2025.docx
18K

NOTICE OF COMMENT PERIOD FOR DRAFT/PROPOSED OPERATING PERMIT RENEWAL

Title V of the Federal Clean Air Act and the state Air Pollution Control Act requires that all major sources and certain minor sources have a permit to operate which states all requirements (e.g. emission limitations, monitoring requirements, etc.) established by regulations promulgated under the aforementioned programs. The Division of Air Quality (DAQ) has determined that the draft/proposed permit renewal referenced herein meets this requirement.

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Mitchell Plant
Plant ID No.: 051-00005
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Comments and questions concerning this matter should be addressed to:

WV Department of Environmental Protection
Division of Air Quality
601 57th Street SE
Charleston, WV 25304
Contact: Dan Roberts
(304) 926-0499 ext.: 41902
Daniel.p.roberts@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Permits Transfer Kentucky Power Company to Wheeling Power Company

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Wed, Mar 19, 2025 at 12:39 PM
To: "Grose, Megan E" <megan.e.grose@wv.gov>
Cc: "Crowder, Laura M" <laura.m.crowder@wv.gov>, "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>, Stephanie R Mink <stephanie.r.mink@wv.gov>

Has the name change from Kentucky to Wheeling Power Company been approved? I was checking because AirTrax still lists Kentucky Power Company.

Dan

On Tue, Aug 8, 2023 at 2:43 PM Grose, Megan E <megan.e.grose@wv.gov> wrote:

> No. You did not sign this one. This is the one I mentioned to you last week or week before last.
>
> Megan E. Grose
>
> Environmental Resource Analyst
>
> WV DEP Division of Air Quality
>
> 601 57th Street S.E.
> Charleston, WV 25304
> 304-926-0499 ext. 43810
> megan.e.grose@wv.gov
>
> On Tue, Aug 8, 2023 at 2:39 PM Crowder, Laura M <laura.m.crowder@wv.gov> wrote:
>
>> Megan,
>>
>> Was this ever finalized?
>>
>> Laura
>>
>> ---------- Forwarded message ---------
>> From: **Grose, Megan E** <megan.e.grose@wv.gov>
>> Date: Mon, Aug 29, 2022 at 11:00 AM
>> Subject: Permits Transfer Kentucky Power Company to Wheeling Power Company
>> To: Laura M Crowder <laura.m.crowder@wv.gov>
>>
>> Laura
>>
>> Attached is the supporting documentation and two letters to be signed for permit transfers from Kentucky Power Company to Wheeling Power Company for the Mitchell Plant. The fee was paid January 28 but the transfer was held awaiting a PSC approval. If you have any questions or see anything that needs to be corrected please let me know.
>>
>> Megan E. Grose
>>
>> Environmental Resource Analyst
>>
>> WV DEP Division of Air Quality
>>
>> 601 57th Street S.E.

> > Charleston, WV 25304
> > 304-926-0499 ext. 43810
> > megan.e.grose@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Fwd: Permits Transfer Kentucky Power Company to Wheeling Power Company

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Wed, Mar 19, 2025 at 11:43 AM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

---------- Forwarded message ---------
From: **Grose, Megan E** <megan.e.grose@wv.gov>
Date: Tue, Aug 8, 2023 at 2:43 PM
Subject: Re: Permits Transfer Kentucky Power Company to Wheeling Power Company
To: Crowder, Laura M <laura.m.crowder@wv.gov>
Cc: Daniel P Roberts <daniel.p.roberts@wv.gov>

No. You did not sign this one. This is the one I mentioned to you last week or week before last.

Megan E. Grose

Environmental Resource Analyst

WV DEP Division of Air Quality

601 57th Street S.E.
Charleston, WV 25304
304-926-0499 ext. 43810
megan.e.grose@wv.gov

On Tue, Aug 8, 2023 at 2:39 PM Crowder, Laura M <laura.m.crowder@wv.gov> wrote:

> Megan,
>
> Was this ever finalized?
>
> Laura
>
> ---------- Forwarded message ---------
> From: **Grose, Megan E** <megan.e.grose@wv.gov>
> Date: Mon, Aug 29, 2022 at 11:00 AM
> Subject: Permits Transfer Kentucky Power Company to Wheeling Power Company
> To: Laura M Crowder <laura.m.crowder@wv.gov>
>
> Laura
>
> Attached is the supporting documentation and two letters to be signed for permit transfers from Kentucky Power Company to Wheeling Power Company for the Mitchell Plant. The fee was paid January 28 but the transfer was held awaiting a PSC approval. If you have any questions or see anything that needs to be corrected please let me know.
>
> Megan E. Grose
>
> Environmental Resource Analyst
>
> WV DEP Division of Air Quality

601 57th Street S.E.
Charleston, WV 25304
304-926-0499 ext. 43810
megan.e.grose@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Fwd: Change of Ownership from Kentucky Power Company to Wheeling Power Company (Facility ID No. 051-00005)

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Wed, Mar 19, 2025 at 11:43 AM
To: "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

---------- Forwarded message ---------
From: **Mink, Stephanie R** <stephanie.r.mink@wv.gov>
Date: Fri, Jul 28, 2023 at 7:45 AM
Subject: Re: Change of Ownership from Kentucky Power Company to Wheeling Power Company (Facility ID No. 051-00005)
To: Roberts, Daniel P <daniel.p.roberts@wv.gov>

Thanks Dan, after I handed it off I wasn't sure what the resolution was since this was a year ago. It dragged on for months because they were waiting for approval from the PSC for the actual ownership changes before they could make things official with us. Looking back at old emails they had hoped to get everything changed over on our end by 9/1/22, I had emails from the end of August where Megan was going to discuss it with Laura because the company was getting in a hurry to close it out. The whole thing was pretty confusing because they had wanted to split ownership between some of the entities and when Laura found out Greg Wooten was handling it she said great, I know him so I'll just get on the phone with him and see what's going on. After that I was just happy to be out of it because I was swamped LOL! Greg should be able to get things on track at this point.

Thanks
Stephanie

On Thu, Jul 27, 2023 at 3:36 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Here's the info I got back from Megan...
>
> ---------- Forwarded message ---------
> From: **Grose, Megan E** <megan.e.grose@wv.gov>
> Date: Thu, Jul 27, 2023 at 3:03 PM
> Subject: Re: Change of Ownership from Kentucky Power Company to Wheeling Power Company (Facility ID No. 051-00005)
> To: Roberts, Daniel P <daniel.p.roberts@wv.gov>
>
> Dan,
>
> Some paperwork was submitted in 2022 to transfer the facility's permits from Kentucky Power to Wheeling Power Company but LMJ had concerns so we did not transfer the permits. Please have them submit all the appropriate paperwork to me to complete the transfer. Thanks,
>
> Megan E. Grose
>
> Environmental Resource Analyst
>
> WV DEP Division of Air Quality
>
> 601 57th Street S.E.
> Charleston, WV 25304
> 304-926-0499 ext. 43810
> megan.e.grose@wv.gov

> On Thu, Jul 27, 2023 at 2:35 PM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:
>
>> Megan,
>>
>> Hey. I have been assigned to review a Title V minor modification for the Mitchell Power Plant in Marshall County. The application was submitted under the company name of Wheeling Power Company, but AirTrax lists the name of the company as Kentucky Power Company. Have they submitted a change of ownership? I didn't see anything in AX. I'm just trying to figure out if they have already submitted the proper documentation or if I need to request them to.
>>
>> Thanks,
>> Dan

Roberts, Daniel P <daniel.p.roberts@wv.gov>

FW: [EXTERNAL] WV DAQ Title V Permit Renewal Application Complete for Wheeling Power Company's Mitchell Plant

1 message

Joshua D Snodgrass <jdsnodgrass@aep.com> Thu, May 30, 2024 at 1:46 PM
To: Daniel P Roberts <daniel.p.roberts@wv.gov>

Thanks Daniel.

AMERICAN ELECTRIC POWER

JOSHUA D SNODGRASS | **PLANT MGR MITCHELL**
JDSNODGRASS@AEP.COM | A:8.276.6005 | C:304.972.7279
8999 ENERGY ROAD, MOUNDSVILLE, WV 26041

From: Roberts, Daniel P <daniel.p.roberts@wv.gov>
Sent: Wednesday, May 29, 2024 4:35 PM
To: Joshua D Snodgrass <jdsnodgrass@aep.com>
Cc: G M Palmer <gmpalmer@aep.com>; Brandon T Belcher <btbelcher@aep.com>; McCumbers, Carrie <Carrie.McCumbers@wv.gov>
Subject: [EXTERNAL] WV DAQ Title V Permit Renewal Application Complete for Wheeling Power Company's Mitchell Plant

RE: Application Status: Complete

Wheeling Power Company

Mitchell Plant

Permit Renewal Application R30-05100005-2024

Mr. Snodgrass,

Your Title V renewal application for a permit to operate the above referenced facility was received by this Division on May 9, 2024. After review of said application, it has been determined that the application is administratively complete as submitted. Therefore, the above referenced facility qualifies for an Application Shield.

The applicant has the duty to supplement or correct the application. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a draft permit.

The submittal of a complete application shall not affect the requirement that any source have all **preconstruction permits** required under the rules of the Division.

If during the processing of this application it is determined that additional information is necessary to evaluate or take final action on this application, a request for such information will be made in writing with a reasonable deadline for a response. Until which time as your renewal permit is issued or denied, please continue to operate this facility in accordance with 45CSR30, section 6.3.c. which states: *If the Secretary fails to take final action to deny or approve a timely and complete permit application before the end of the term of the previous permit, the permit shall not expire until the renewal permit has been issued or denied, and any permit shield granted for the permit shall continue in effect during that time.* This protection shall cease to apply if, subsequent to the completeness determination made pursuant to paragraph 6.1.d. of 45CSR30 and as required by paragraph 4.1.b., the applicant fails to submit by the deadline specified in writing any additional information identified as being needed to process the application.

Please remember, **failure of the applicant to timely submit information required or requested to process the application may cause the Application Shield to be revoked.** Should you have any questions regarding this determination, please call me at (304)926-0499 ext. 41902.

Sincerely,

Daniel P. Roberts

WV Department of Environmental Protection

Division of Air Quality

(304) 926-0499 ext. 41902

Daniel.p.roberts@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Read: [EXTERNAL] WV DAQ Title V Permit Renewal Application Complete for Wheeling Power Company's Mitchell Plant

1 message

Joshua D Snodgrass <jdsnodgrass@aep.com> Thu, May 30, 2024 at 12:44 PM
To: "daniel.p.roberts@wv.gov" <daniel.p.roberts@wv.gov>

Your message

To: Joshua D Snodgrass
Subject: [EXTERNAL] WV DAQ Title V Permit Renewal Application Complete for Wheeling Power Company's Mitchell Plant
Sent: Wednesday, May 29, 2024 4:34:31 PM (UTC-05:00) Eastern Time (US & Canada)

was read on Thursday, May 30, 2024 12:43:31 PM (UTC-05:00) Eastern Time (US & Canada).

Roberts, Daniel P <daniel.p.roberts@wv.gov>

WV DAQ Title V Permit Renewal Application Complete for Wheeling Power Company's Mitchell Plant

1 message

Roberts, Daniel P <daniel.p.roberts@wv.gov> Wed, May 29, 2024 at 4:34 PM
To: jdsnodgrass@aep.com
Cc: gmpalmer@aep.com, btbelcher@aep.com, "McCumbers, Carrie" <Carrie.McCumbers@wv.gov>

RE: Application Status: Complete

Wheeling Power Company

Mitchell Plant

Permit Renewal Application R30-05100005-2024

Mr. Snodgrass,

Your Title V renewal application for a permit to operate the above referenced facility was received by this Division on May 9, 2024. After review of said application, it has been determined that the application is administratively complete as submitted. Therefore, the above referenced facility qualifies for an Application Shield.

The applicant has the duty to supplement or correct the application. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a draft permit.

The submittal of a complete application shall not affect the requirement that any source have all **preconstruction permits** required under the rules of the Division.

If during the processing of this application it is determined that additional information is necessary to evaluate or take final action on this application, a request for such information will be made in writing with a reasonable deadline for a response. Until which time as your renewal permit is issued or denied, please continue to operate this facility in accordance with 45CSR30, section 6.3.c. which states: *If the Secretary fails to take final action to deny or approve a timely and complete permit application before the end of the term of the previous permit, the permit shall not expire until the renewal permit has been issued or denied, and any permit shield granted for the permit shall continue in effect during that time.* This protection shall cease to apply if, subsequent to the completeness determination made pursuant to paragraph 6.1.d. of 45CSR30 and as required by paragraph 4.1.b., the applicant fails to submit by the deadline specified in writing any additional information identified as being needed to process the application.

Please remember, **failure of the applicant to timely submit information required or requested to process the application may cause the Application Shield to be revoked.** Should you have any questions regarding this determination, please call me at (304)926-0499 ext. 41902.

Sincerely,

Daniel P. Roberts

WV Department of Environmental Protection

Division of Air Quality

(304) 926-0499 ext. 41902

Daniel.p.roberts@wv.gov

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Re: Wheeling Power renewal

1 message

Mink, Stephanie R <stephanie.r.mink@wv.gov> Wed, May 15, 2024 at 8:27 AM
To: "Roberts, Daniel P" <daniel.p.roberts@wv.gov>

Thank you!

On Wed, May 15, 2024 at 8:24 AM Roberts, Daniel P <daniel.p.roberts@wv.gov> wrote:

> Thanks for the background info. I will keep you updated if/when any changes are made just to let you know it has been done.
>
> Dan
>
> On Fri, May 10, 2024 at 10:50 AM Mink, Stephanie R <stephanie.r.mink@wv.gov> wrote:
>
>> Hi Dan,
>>
>> Here's a dated copy of the application, in Airtrax this is still listed as Kentucky Power and I didn't change the Rolodex. Some time ago AEP was going through some name/ownership changes. I started out working with Greg Palmer on it and as the process kept getting delayed I handed it off to Megan Grose once she was hired since transfers, etc. are handled in her office. I would suggest getting in touch with her to see what happened there and see if the paperwork was ever completed. She updates Airtrax when transfers are done so it may never have happened. Just wanted to give you a bit of a back story on what has gone on over the last year or two.
>>
>> Have a good weekend!
>>
>> --
>>

>> Stephanie Mink
>>
>> Environmental Resources Associate
>>
>> West Virginia Department of Environmental Protection
>>
>> Division of Air Quality, Title V & NSR Permitting
>>
>> 601 57th Street SE
>>
>> Charleston, WV 25304
>>
>> Phone: 304-926-0499 x41281

Roberts, Daniel P <daniel.p.roberts@wv.gov>

WV DAQ Title V Permit Application Status for Wheeling Power Company; Mitchell Plant

1 message

Mink, Stephanie R <stephanie.r.mink@wv.gov> Fri, May 10, 2024 at 10:57 AM
To: jdsnodgrass@aep.com, gmpalmer@aep.com, btbelcher@aep.com
Cc: Carrie McCumbers <carrie.mccumbers@wv.gov>, Daniel P Roberts <daniel.p.roberts@wv.gov>

RE: Application Status

Wheeling Power Company

Mitchell Plant

Facility ID No. 051-00005

Application No. R30-05100005-2024

Dear Mr. Snodgrass,

Your application for a Title V Permit Renewal for Wheeling Power Company's Mitchell Plant was received by this Division on May 9, 2024, and was assigned to Dan Roberts.

Should you have any questions, please contact the assigned permit writer, Dan Roberts, at 304-926-0499, extension 41902, or Daniel.P.Roberts@wv.gov .

--

Stephanie Mink

Environmental Resources Associate

West Virginia Department of Environmental Protection

Division of Air Quality, Title V & NSR Permitting

601 57th Street SE

Charleston, WV 25304

Phone: 304-926-0499 x41281

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Wheeling Power renewal

1 message

Mink, Stephanie R <stephanie.r.mink@wv.gov> Fri, May 10, 2024 at 10:49 AM
To: Daniel P Roberts <daniel.p.roberts@wv.gov>

Hi Dan,

Here's a dated copy of the application, in Airtrax this is still listed as Kentucky Power and I didn't change the Rolodex. Some time ago AEP was going through some name/ownership changes. I started out working with Greg Palmer on it and as the process kept getting delayed I handed it off to Megan Grose once she was hired since transfers, etc. are handled in her office. I would suggest getting in touch with her to see what happened there and see if the paperwork was ever completed. She updates Airtrax when transfers are done so it may never have happened. Just wanted to give you a bit of a back story on what has gone on over the last year or two.

Have a good weekend!

--

Stephanie Mink

Environmental Resources Associate

West Virginia Department of Environmental Protection

Division of Air Quality, Title V & NSR Permitting

601 57th Street SE

Charleston, WV 25304

Phone: 304-926-0499 x41281

R30-05100005-2024 Wheeling Power renewal-Dan.pdf
20909K

Received
May 9, 2024
WV DEP/Div of Air Quality

Division of Air Quality Permit Application Submittal

Please find attached a permit application for : Wheeling Power Company; Mitchell Plant
[Company Name; Facility Location]

- DAQ Facility ID (for existing facilities only): 03-054-05100005
- Current 45CSR13 and 45CSR30 (Title V) permits associated with this process (for existing facilities only): R30-05100005-2019 (MM01)

- Type of NSR Application (check all that apply):
  - ☐ Construction
  - ☐ Modification
  - ☐ Class I Administrative Update
  - ☐ Class II Administrative Update
  - ☐ Relocation
  - ☐ Temporary
  - ☐ Permit Determination

- Type of 45CSR30 (TITLE V) Application:
  - ☐ Title V Initial
  - ☑ Title V Renewal
  - ☐ Administrative Amendment**
  - ☑ Minor Modification**
  - ☐ Significant Modification**
  - ☐ Off Permit Change

****If the box above is checked, include the Title V revision information as ATTACHMENT S to the combined NSR/Title V application.**

- Payment Type:
  - ☐ Credit Card (Instructions to pay by credit card will be sent in the Application Status email.)
  - ☑ Check (Make checks payable to: WVDEP – Division of Air Quality)
    Mail checks to:
    WVDEP – DAQ – Permitting
    Attn: NSR Permitting Secretary
    601 57th Street, SE
    Charleston, WV 25304

Please wait until DAQ emails you the Facility ID Number and Permit Application Number. Please add these identifiers to your check or cover letter with your check.

- If the permit writer has any questions, please contact (all that apply):
  - ☐ Responsible Official/Authorized Representative
    - Name: Joshua D. Snodgrass
    - Email: jdsnodgrass@aep.com
    - Phone Number: 304-843-6005
  - ☑ Company Contact
    - Name: G. M.(Matt) Palmer
    - Email: gmpalmer@aep.com
    - Phone Number: 304-843-6048
  - ☑ Consultant
    - Name: Brandon T. Belcher
    - Email: btbelcher@aep.com
    - Phone Number: 304-541-7437

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY

American Electric Power
1 Riverside Plaza
Columbus, OH 43215
aep.com

May 9, 2024

Ms. Laura M. Crowder, Director (electronically via DEPAirQualityPermitting@wv.gov)
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, West Virginia 25304

RE: 45 CSR 30 Permit Renewal Application
Plant ID# 051-00005

Dear Ms. Crowder:

In accordance with Condition 2.3 for the subject permit, enclosed is an electronic copy (via email) of a signed Title V Permit Renewal Application for Wheeling Power Company's Mitchell Plant. The subject application is for the Steam Electric Generating Facility located near Moundsville, WV in Marshall County. The existing permit expires on November 26, 2024.

Please contact Brandon T. Belcher at (304) 541-7437 or G. M. (Matt) Palmer at (304) 843-6048 if you have any questions.

Sincerely,

Joshua D. Snodgrass
Plant Manager, Mitchell Plant

Re: 45 CSR 30 Permit Renewal Application
Plant ID# 051-00005

ec: T. W. Lohner / B. T. Belcher — Environmental Services
G. M. Palmer / D. R. Roski — Mitchell Plant

Enclosure: Mitchell Plant Title V Renewal Application Package

Wheeling Power Company
Mitchell Plant

Title V Permit Renewal Application
R30-05100005-2019 (MM01)

Prepared For:

Wheeling Power Company
Mitchell Plant
Moundsville, West Virginia

Prepared By:

American Electric Power
Environmental Services
1 Riverside Plaza
Columbus, Ohio 43215
May 2024

Wheeling Power Company
Mitchell Plant

Regulation 30 Permit Renewal Application

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WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION

DIVISION OF AIR QUALITY

601 57th Street SE
Charleston, WV 25304
Phone: (304) 926-0475
www.dep.wv.gov/daq

INITIAL/RENEWAL TITLE V PERMIT APPLICATION - GENERAL FORMS

Section 1: General Information

1. Name of Applicant (As registered with the WV Secretary of State's Office):
Wheeling Power Company

2. Facility Name or Location:
Mitchell Plant

3. DAQ Plant ID No.:
051-00005

4. Federal Employer ID No. (FEIN):
610247775

5. Permit Application Type:

- ☐ Initial Permit — When did operations commence? 1970
- ☑ Permit Renewal — What is the expiration date of the existing permit? 11/26/2024
- ☐ Update to Initial/Renewal Permit Application

6. Type of Business Entity:

☑ Corporation ☐ Governmental Agency ☐ LLC
☐ Partnership ☐ Limited Partnership

7. Is the Applicant the:

☐ Owner ☐ Operator ☑ Both

If the Applicant is not both the owner and operator, please provide the name and address of the other party.

8. Number of onsite employees:
Approx. 181

9. Governmental Code:

- ☑ Privately owned and operated; 0
- ☐ Federally owned and operated; 1
- ☐ State government owned and operated; 2
- ☐ County government owned and operated; 3
- ☐ Municipality government owned and operated; 4
- ☐ District government owned and operated; 5

10. Business Confidentiality Claims

Does this application include confidential information (per 45CSR31)? ☐ Yes ☑ No

If yes, identify each segment of information on each page that is submitted as confidential, and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's *"PRECAUTIONARY NOTICE-CLAIMS OF CONFIDENTIALITY"* guidance.

11. Mailing Address		
Street or P.O. Box: P.O. Box K		
City: Moundsville	**State:** West Virginia	**Zip:** 26041
Telephone Number: (304) 843-6000	**Fax Number:** (304) 843-6080	

12. Facility Location (Physical Address)		
Street: State Route 2	**City:** Cresap/Moundsville	**County:** Marshall
UTM Easting: 516.00 km	**UTM Northing:** 4409.00 km	**Zone:** ☑ 17 or ☐ 18
Directions: From Charleston, WV, take I-77 N to Exit 179. Travel north on State Route 2 approximately 70 miles to Cresap, WV. Facility is located on State Route 2, approximately 9 miles south of Moundsville, WV.		
Portable Source? ☐ Yes ☑ No		
Is facility located within a nonattainment area? ☑ Yes ☐ No		**If yes, for what air pollutants?** Sulfur Dioxide
Is facility located within 50 miles of another state? ☑ Yes ☐ No		**If yes, name the affected state(s).** Ohio, Pennsylvania
Is facility located within 100 km of a Class I Area[1]? ☐ Yes ☑ No **If no, do emissions impact a Class I Area[1]?** ☑ Yes ☐ No		**If yes, name the area(s).**

[1] *Class I areas include Dolly Sods and Otter Creek Wilderness Areas in West Virginia, and Shenandoah National Park and James River Face Wilderness Area in Virginia.*

13. Contact Information		
Responsible Official: Joshua D. Snodgrass		**Title:** Plant Manager
Street or P.O. Box: P.O. Box K		
City: Moundsville	**State:** WV	**Zip:** 26041
Telephone Number: (304) 843-6005	**Cell Number:** (304) 972-7279	
E-mail address: jdsnodgrass@aep.com		
Environmental Contact: G. M. (Matt) Palmer		**Title:** Plant Environmental Coordinator
Street or P.O. Box: P.O. Box K		
City: Moundsville	**State:** WV	**Zip:** 26041
Telephone Number: (304) 843-6048	**Cell Number:** (304) 559-4538	
E-mail address: gmpalmer@aep.com		
Application Preparer: Brandon T. Belcher		**Title:** Environmental Specialist Sr.
Company: AEP Service Corporation		
Street or P.O. Box: 1 Riverside Plaza, 17th Floor		
City: Columbus	**State:** OH	**Zip:** 43215
Telephone Number: (614) 716-1800	**Cell Number:** (304) 541-7437	
E-mail address: btbelcher@aep.com		

14. Facility Description

List all processes, products, NAICS and SIC codes for normal operation, in order of priority. Also list any process, products, NAICS and SIC codes associated with any alternative operating scenarios if different from those listed for normal operation.

Process	Products	NAICS	SIC
Coal Fired Electric Generating Unit	Electricity	221112	4911

Provide a general description of operations.

The Mitchell Plant is a fossil fuel fired electric generation facility and operates under Standard Industrial Code (SIC) 4911. The facility consists of two coal-fired steam generators that provide a steam supply to turbine driven electrical generators, and an oil-fired auxiliary boiler that provides auxiliary steam services to the facility. The facility also includes various supporting operations including by not limited to coal handling, ash handling, gypsum handling, limestone handling, wastewater treatment system filter cake handling, and various tanks with insignificant emissions. The facility has the potential to operate seven days per week, twenty-four hours per day, and 52 weeks per year.

15. Provide an **Area Map** showing plant location as **ATTACHMENT A**.

16. Provide a **Plot Plan(s)**, e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is located as **ATTACHMENT B**. For instructions, refer to “Plot Plan - Guidelines.”

17. Provide a detailed **Process Flow Diagram(s)** showing each process or emissions unit as **ATTACHMENT C**. Process Flow Diagrams should show all emission units, control equipment, emission points, and their relationships.

Section 2: Applicable Requirements

18. Applicable Requirements Summary	
Instructions: Mark all applicable requirements.	
☑ SIP	☐ FIP
☑ Minor source NSR (45CSR13)	☐ PSD (45CSR14)
☑ NESHAP (45CSR34)	☐ Nonattainment NSR (45CSR19)
☑ Section 111 NSPS	☐ Section 112(d) MACT standards
☐ Section 112(g) Case-by-case MACT	☐ 112(r) RMP
☐ Section 112(i) Early reduction of HAP	☐ Consumer/commercial prod. reqts., section 183(e)
☐ Section 129 Standards/Reqts.	☐ Stratospheric ozone (Title VI)
☐ Tank vessel reqt., section 183(f)	☐ Emissions cap 45CSR§30-2.6.1
☐ NAAQS, increments or visibility (temp. sources)	☐ 45CSR27 State enforceable only rule
☑ 45CSR4 State enforceable only rule	☐ Acid Rain (Title IV, 45CSR33)
☐ Emissions Trading and Banking (45CSR28)	☐ **C**ompliance **A**ssurance **M**onitoring (40CFR64)
☐ Cross-State Air Pollution Rule (45CSR43)	

19. Non Applicability Determinations

List all requirements which the source has determined not applicable and for which a permit shield is requested. The listing shall also include the rule citation and the reason why the shield applies.

45 CSR 5: Pursuant to 45CSR5, if 45CSR2 is applicable to the facility, then the facility is exempt from 45CSR5. 45CSR2 is applicable to the facility.

45 CSR 17: Pursuant to 45CSR17, if 45CSR2 is applicable to the facility, then the facility is exempt from 45CSR17. 45CSR2 is applicable to the facility.

40 CFR 60 Subpart D: The fossil fuel fired steam generators potentially affected by this rule have not commenced construction or modification after August 17, 1971.

40 CFR 60 Subpart Da: The electric utility steam generating units potentially affected by this rule have not commenced construction or modification after September 18, 1978.

40 CFR 60 Subpart K: The facility doesn't include storage vessels that are used to store petroleum liquids (as defined in 40 CFR 60.111(b)) and have storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification commenced after June 11, 1973 and prior to May 19, 1978.

☐ Permit Shield

19. Non Applicability Determinations *(Continued)* *- Attach additional pages as necessary.*

List all requirements which the source has determined not applicable and for which a permit shield is requested. The listing shall also include the rule citation and the reason why the shield applies.

40 CFR 60 Subpart Ka: The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 CFR 60.111(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification was commenced after May 18, 1978 and prior to July 23, 1984.

40 CFR 60 Subpart Kb: Storage vessels potentially affected by this rule are exempted because they contain liquids with a maximum true vapor pressure of less than 3.5 kPa, have a storage capacity of less than 40 cubic meters, or have not commenced construction, reconstruction or modification after July 23, 1984.

40 CFR 60 Subpart Y: The coal handling equipment potentially affected by this rule has not been constructed or modified after October 24, 1974.

40 CFR 63 Subpart Q: This facility does not include industrial process cooling towers that have operated with chromium-based water treatment chemicals on or after September 8, 1994.

☐ Permit Shield

20. Facility-Wide Applicable Requirements

List all facility-wide applicable requirements. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*).

45CSR6-3, R30-05100005-2019 (MM01) Section 3.1.1 and 3.1.2 (Open Burning)

40CFR61, 45CSR34, and R30-05100005-2019 (MM01) Section 3.1.3 (Asbestos)

45CSR4, R30-05100005-2019 (MM01) Section 3.1.4 (Odor)

45CSR11-5.2, R30-05100005-2019 (MM01) Section 3.1.5 (Standby Plan)

WV Code 22-5-4(a)(14), R30-05100005-2019 (MM01) Section 3.1.6 (Emission Inventory)

40CFR82 Subpart F, R30-05100005-2019 (MM01) Section 3.1.7 (Ozone-depleting Substances)

45CSR2-5, 45CSR13, R13-2608, 4.1.18, and R30-05100005-2019 (MM01) Section 3.1.9 (Fugitive Particulate Matter Control)

40CFR97.406, , 45CSR43, and R30-05100005-2019 (MM01) Section 3.1.11 (CSAPR NOx Annual Trading Program)

☐ Permit Shield

For all facility-wide applicable requirements listed above, provide monitoring/testing / recordkeeping / reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number and/or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45CSR2, 45CSR10, and WV Code 22-5-4(a)(14-15), R30-05100005-2019 (MM01) Section 3.3.1 (Stack Testing)

45CSR30-5.1.c.2.A, R30-05100005-2019 (MM01) Section 3.4.1 (Monitoring Information)

45CSR30-5.1.c.2.B, R30-05100005-2019 (MM01) Section 3.4.2 (Retention of Records)

45CSR30-5.1.c, R30-05100005-2019 (MM01) Section 3.4.3 (Odors)

45CSR30-5.1.c, R30-05100005-2019 (MM01) Section 3.4.4 (Fugitive Particulate Matter Control)

45CSR30-4.4 and 5.1.c.3, R30-05100005-2019 (MM01) Sections 3.5.1-3.5.3 (Reporting Requirements)

45CSR30-8, R30-05100005-2019 (MM01) Section 3.5.4 (Certified Emissions Statement)

Are you in compliance with all facility-wide applicable requirements? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

20. Facility-Wide Applicable Requirements *(Continued)* - *Attach additional pages as necessary.*

List all facility-wide applicable requirements. For each applicable requirement, include the rule citation and/or permit with the condition number.

40CFR97.806, 45CSR43, and R30-05100005-2019 (MM01) Section 3.1.12 (CSAPR NOx Ozone Season Trading Program)

40CFR97.606, 45CSR43, and R30-05100005-2019 (MM01) Section 3.1.13 (CSAPR SO2 Group 1 Trading Program)

☐ Permit Shield

For all facility-wide applicable requirements listed above, provide monitoring/testing/recordkeeping/ reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number and/or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45CSR30-5.3.e, R30-05100005-2019 (MM01) Section 3.5.5 (Compliance Certification)

45CSR30-5.1.c.3.A, R30-05100005-2019 (MM01) Section 3.5.6 (Semi-Annual Monitoring Reports)

R30-05100005-2019 (MM01) Section 3.5.7 (Emergency Reporting)

45CSR30-5.1.c.3, R30-05100005-2019 (MM01) Section 3.5.8 (Deviation Reports)

45CSR30-4.3.h.1.B, R30-05100005-2019 (MM01) Section 3.5.9 (New Applicable Requirements)

Are you in compliance with all facility-wide applicable requirements? ☐ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Page _____ of _____

21. Active Permits/Consent Orders		
Permit or Consent Order Number	Date of Issuance MM/DD/YYYY	List any Permit Determinations that Affect the Permit *(if any)*
	05/12/2004	PD04-042: No permit needed for SCR
	08/05/2004	PD04-064: No permit needed for FGD system
	08/24/2005	PD04-073: No permit needed for urea handling
R13-2608E	05/12/2014	Reg 13 Permit for FGD support equipment, Dry Fly Ash and Ash Landfill project, and Aux. Boiler rebuild project/capacity factor limit.
U.S. District Court Consent Decree regarding Civil Actions C2-99-1182, C2-05-360, and C2-04-1098	12/13/2007	Consent Decree for NSR lawsuits
R33-3948-2027-6	12/19/2022	Acid Rain Permit
G60-C057A	08/08/2014	Emergency Generator General Permit

22. Inactive Permits/Obsolete Permit Conditions

Permit Number	Date of Issuance MM/DD/YYYY	Permit Condition Number
R13-2608 through R13-2608D	Various	Permits were revised and replaced with subsequent versions.
G60-C057	10/11/2013	Permit was revised and replaced with subsequent version.

Page _____ of _____

Section 3: Facility-Wide Emissions

23. Facility-Wide Emissions Summary [Tons per Year]

Criteria Pollutants	Potential Emissions
Carbon Monoxide (CO)	4743.23
Nitrogen Oxides (NO_X)	36332.05
Lead (Pb)	3.643
Particulate Matter ($PM_{2.5}$)[1]	1096.2
Particulate Matter (PM_{10})[1]	3169.0
Total Particulate Matter (TSP)	5423.79
Sulfur Dioxide (SO_2)	89743.04
Volatile Organic Compounds (VOC)	559.82
Hazardous Air Pollutants[2]	Potential Emissions
Hydrogen Chloride	12337
Hydrogen Fluoride	1071
Selenium	48.45
Manganese	3.77
Nickel	1.69
Arsenic	5.62
Mercury Compounds	2.13
Beryllium	13.37
Chromium	2.00
Cobalt	0.74
Lead	3.65
Regulated Pollutants other than Criteria and HAP	Potential Emissions

[1]$PM_{2.5}$ and PM_{10} are components of TSP.
[2]For HAPs that are also considered PM or VOCs, emissions should be included in both the HAPs section and the Criteria Pollutants section.

Page _____ of _____

Section 4: Insignificant Activities

24. Insignificant Activities (Check all that apply)		
☑	1.	Air compressors and pneumatically operated equipment, including hand tools.
☑	2.	Air contaminant detectors or recorders, combustion controllers or shutoffs.
☑	3.	Any consumer product used in the same manner as in normal consumer use, provided the use results in a duration and frequency of exposure which are not greater than those experienced by consumer, and which may include, but not be limited to, personal use items; janitorial cleaning supplies, office supplies and supplies to maintain copying equipment.
☑	4.	Bathroom/toilet vent emissions.
☑	5.	Batteries and battery charging stations, except at battery manufacturing plants.
☑	6.	Bench-scale laboratory equipment used for physical or chemical analysis, but not lab fume hoods or vents. Many lab fume hoods or vents might qualify for treatment as insignificant (depending on the applicable SIP) or be grouped together for purposes of description.
☐	7.	Blacksmith forges.
☑	8.	Boiler water treatment operations, not including cooling towers.
☑	9.	Brazing, soldering or welding equipment used as an auxiliary to the principal equipment at the source.
☐	10.	CO_2 lasers, used only on metals and other materials which do not emit HAP in the process.
☑	11.	Combustion emissions from propulsion of mobile sources, except for vessel emissions from Outer Continental Shelf sources.
☑	12.	Combustion units designed and used exclusively for comfort heating that use liquid petroleum gas or natural gas as fuel.
☑	13.	Comfort air conditioning or ventilation systems not used to remove air contaminants generated by or released from specific units of equipment.
☑	14.	Demineralized water tanks and demineralizer vents.
☐	15.	Drop hammers or hydraulic presses for forging or metalworking.
☑	16.	Electric or steam-heated drying ovens and autoclaves, but not the emissions from the articles or substances being processed in the ovens or autoclaves or the boilers delivering the steam.
☐	17.	Emergency (backup) electrical generators at residential locations.
☑	18.	Emergency road flares.
☐	19.	Emission units which do not have any applicable requirements and which emit criteria pollutants (CO, NO_x, SO_2, VOC and PM) into the atmosphere at a rate of less than 1 pound per hour and less than 10,000 pounds per year aggregate total for each criteria pollutant from all emission units. Please specify all emission units for which this exemption applies along with the quantity of criteria pollutants emitted on an hourly and annual basis:

Page _____ of _____

24. Insignificant Activities (Check all that apply)		
☐	20.	Emission units which do not have any applicable requirements and which emit hazardous air pollutants into the atmosphere at a rate of less than 0.1 pounds per hour and less than 1,000 pounds per year aggregate total for all HAPs from all emission sources. This limitation cannot be used for any source which emits dioxin/furans nor for toxic air pollutants as per 45CSR27. Please specify all emission units for which this exemption applies along with the quantity of hazardous air pollutants emitted on an hourly and annual basis:
☐	21.	Environmental chambers not using hazardous air pollutant (HAP) gases.
☑	22.	Equipment on the premises of industrial and manufacturing operations used solely for the purpose of preparing food for human consumption.
☐	23.	Equipment used exclusively to slaughter animals, but not including other equipment at slaughterhouses, such as rendering cookers, boilers, heating plants, incinerators, and electrical power generating equipment.
☑	24.	Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.
☑	25.	Equipment used for surface coating, painting, dipping or spray operations, except those that will emit VOC or HAP.
☑	26.	Fire suppression systems.
☑	27.	Firefighting equipment and the equipment used to train firefighters.
☐	28.	Flares used solely to indicate danger to the public.
☑	29.	Fugitive emission related to movement of passenger vehicle provided the emissions are not counted for applicability purposes and any required fugitive dust control plan or its equivalent is submitted.
☐	30.	Hand-held applicator equipment for hot melt adhesives with no VOC in the adhesive formulation.
☑	31.	Hand-held equipment for buffing, polishing, cutting, drilling, sawing, grinding, turning or machining wood, metal or plastic.
☐	32.	Humidity chambers.
☑	33.	Hydraulic and hydrostatic testing equipment.
☑	34.	Indoor or outdoor kerosene heaters.
☑	35.	Internal combustion engines used for landscaping purposes.
☐	36.	Laser trimmers using dust collection to prevent fugitive emissions.
☑	37.	Laundry activities, except for dry-cleaning and steam boilers.
☐	38.	Natural gas pressure regulator vents, excluding venting at oil and gas production facilities.
☑	39.	Oxygen scavenging (de-aeration) of water.
☑	40.	Ozone generators.

24. Insignificant Activities (Check all that apply)		
☑	41.	Plant maintenance and upkeep activities (e.g., grounds-keeping, general repairs, cleaning, painting, welding, plumbing, re-tarring roofs, installing insulation, and paving parking lots) provided these activities are not conducted as part of a manufacturing process, are not related to the source's primary business activity, and not otherwise triggering a permit modification. (Cleaning and painting activities qualify if they are not subject to VOC or HAP control requirements. Asphalt batch plant owners/operators must still get a permit if otherwise requested.)
☑	42.	Portable electrical generators that can be moved by hand from one location to another. "Moved by Hand" means that it can be moved without the assistance of any motorized or non-motorized vehicle, conveyance, or device.
☑	43.	Process water filtration systems and demineralizers.
☑	44.	Repair or maintenance shop activities not related to the source's primary business activity, not including emissions from surface coating or de-greasing (solvent metal cleaning) activities, and not otherwise triggering a permit modification.
☑	45.	Repairs or maintenance where no structural repairs are made and where no new air pollutant emitting facilities are installed or modified.
☑	46.	Routing calibration and maintenance of laboratory equipment or other analytical instruments.
☐	47.	Salt baths using nonvolatile salts that do not result in emissions of any regulated air pollutants. Shock chambers.
☐	48.	Shock chambers.
☐	49.	Solar simulators.
☑	50.	Space heaters operating by direct heat transfer.
☑	51.	Steam cleaning operations.
☑	52.	Steam leaks.
☐	53.	Steam sterilizers.
☑	54.	Steam vents and safety relief valves.
☑	55.	Storage tanks, reservoirs, and pumping and handling equipment of any size containing soaps, vegetable oil, grease, animal fat, and nonvolatile aqueous salt solutions, provided appropriate lids and covers are utilized.
☑	56.	Storage tanks, vessels, and containers holding or storing liquid substances that will not emit any VOC or HAP. Exemptions for storage tanks containing petroleum liquids or other volatile organic liquids should be based on size limits such as storage tank capacity and vapor pressure of liquids stored and are not appropriate for this list.
☐	57.	Such other sources or activities as the Director may determine.
☑	58.	Tobacco smoking rooms and areas.
☑	59.	Vents from continuous emissions monitors and other analyzers.

Page _____ of _____

Section 5: Emission Units, Control Devices, and Emission Points

25. Equipment Table
Fill out the **Title V Equipment Table** and provide it as **ATTACHMENT D**.
26. Emission Units
For each emission unit listed in the **Title V Equipment Table**, fill out and provide an **Emission Unit Form** as **ATTACHMENT E**.
For each emission unit not in compliance with an applicable requirement, fill out a **Schedule of Compliance Form** as **ATTACHMENT F**.
27. Control Devices
For each control device listed in the **Title V Equipment Table**, fill out and provide an **Air Pollution Control Device Form** as **ATTACHMENT G**.
For any control device that is required on an emission unit in order to meet a standard or limitation for which the potential pre-control device emissions of an applicable regulated air pollutant is greater than or equal to the Title V Major Source Threshold Level, refer to the **Compliance Assurance Monitoring (CAM) Form(s)** for CAM applicability. Fill out and provide these forms, if applicable, for each Pollutant Specific Emission Unit (PSEU) as **ATTACHMENT H**.

Section 6: Certification of Information

28. Certification of Truth, Accuracy and Completeness and Certification of Compliance

Note: This Certification must be signed by a responsible official as defined in 45CSR§30-2.38.

a. Certification of Truth, Accuracy and Completeness

I certify that I am a responsible official (as defined at 45CSR§30-2.38) and am accordingly authorized to make this submission on behalf of the owners or operators of the source described in this document and its attachments. I certify under penalty of law that I have personally examined and am familiar with the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine and/or imprisonment.

b. Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

Responsible official (type or print)

Name:	Title:
Joshua D. Snodgrass	Plant Manager

Responsible official's signature:

Signature: [signature] Signature Date: 5/9/24

(Must be signed and dated in blue ink or have a valid electronic signature)

Note: Please check all applicable attachments included with this permit application:

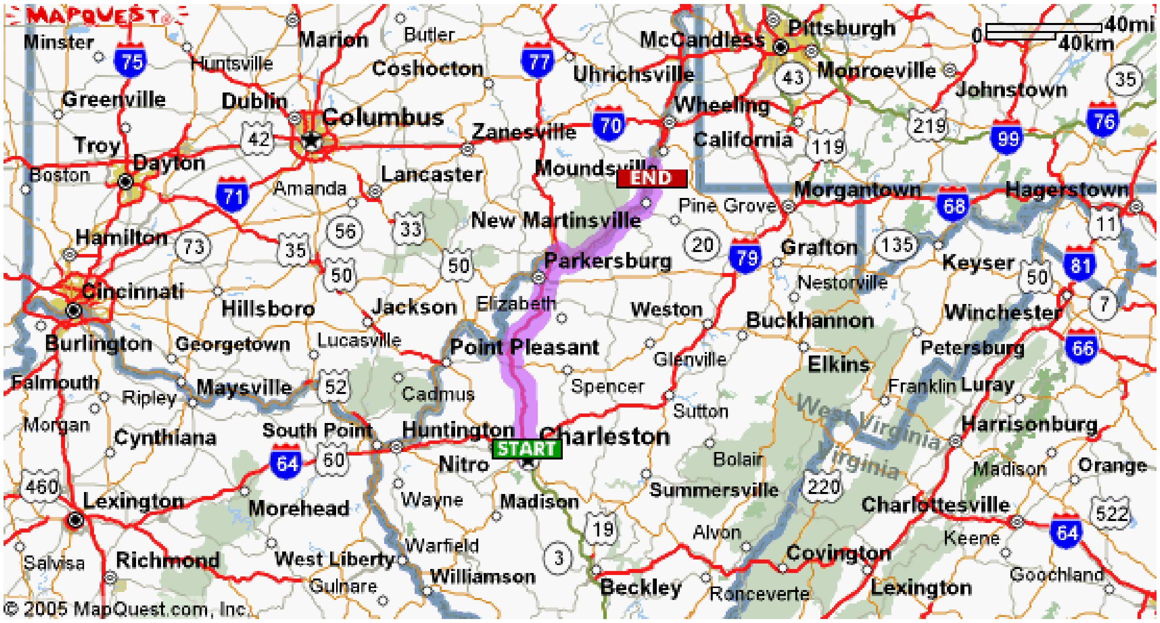
☑	ATTACHMENT A: Area Map
☑	ATTACHMENT B: Plot Plan(s)
☑	ATTACHMENT C: Process Flow Diagram(s)
☑	ATTACHMENT D: Equipment Table
☑	ATTACHMENT E: Emission Unit Form(s)
☐	ATTACHMENT F: Schedule of Compliance Form(s)
☑	ATTACHMENT G: Air Pollution Control Device Form(s)
☑	ATTACHMENT H: Compliance Assurance Monitoring (CAM) Form(s)

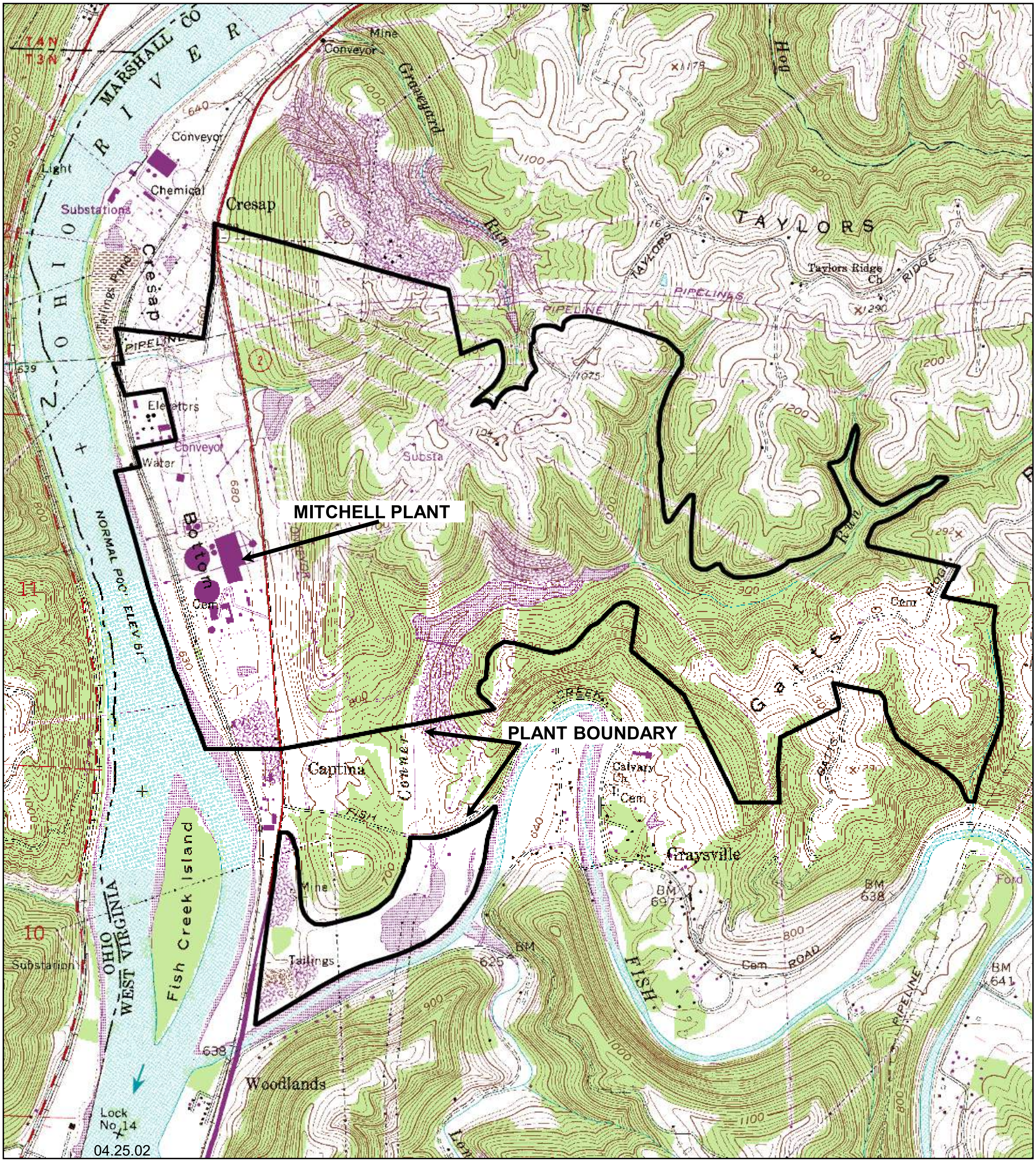
All of the required forms and additional information can be found and downloaded from, the DEP website at www.dep.wv.gov/daq, requested by phone (304) 926-0475, and/or obtained through the mail.

Attachment A

Area Map

Driving directions to Mitchell Plant: From Charleston, take Interstate 77 North to Exit 179. Travel north on State Route 2 approximately 70 miles to Cresap. Facility is located on Route 2 approximately nine miles south of Moundsville, WV.





N

Powhatan Point, W.VA. - OH
Quadrangle

USGS Topographic Map

0 ½ 1mi

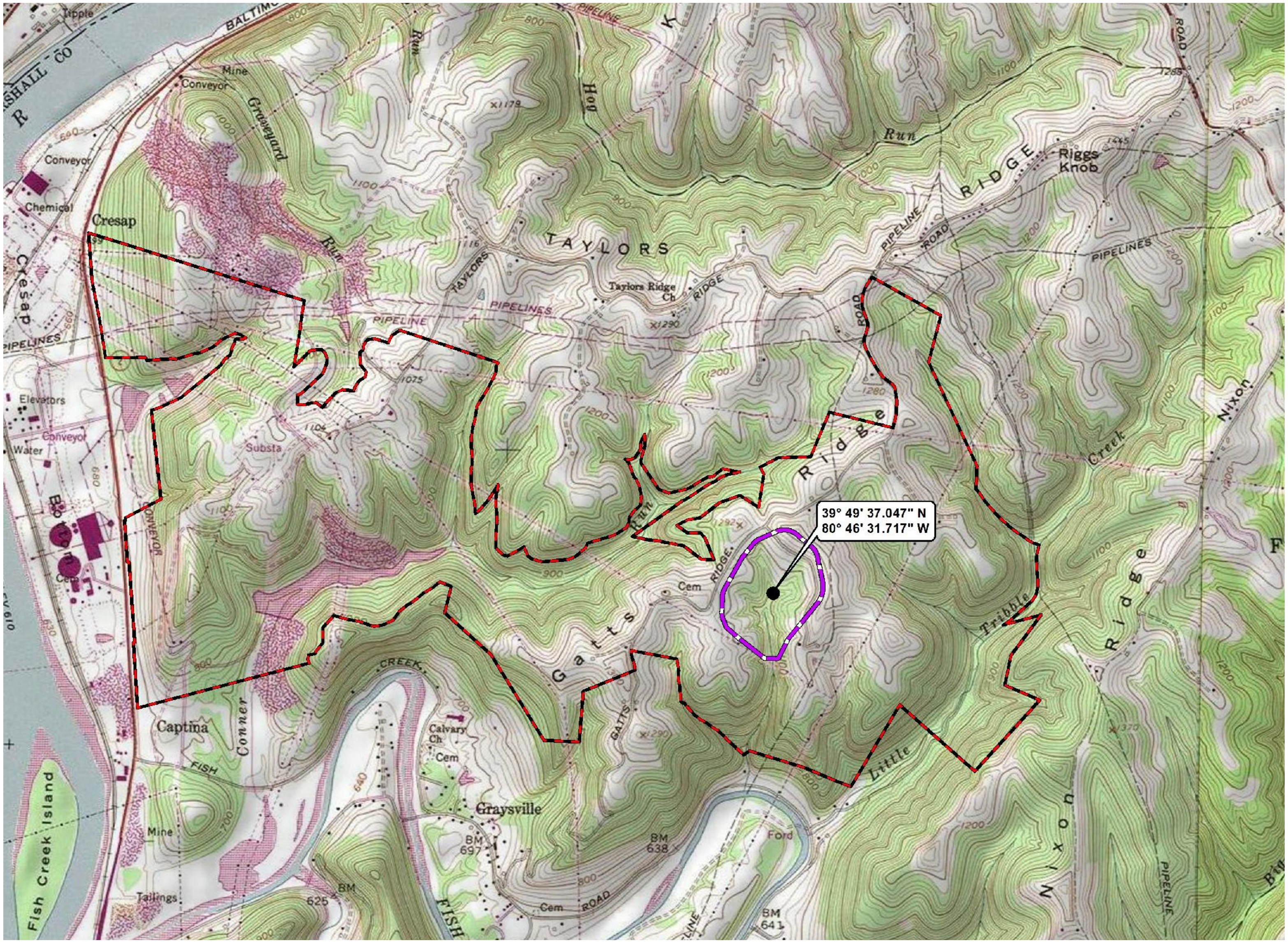
Plant Latitude 39° 49' 45"
Plant Longitude 80° 48' 59"

Wheeling Power Company
Mitchell Plant

Facility Boundary

Air Quality Services

Mitchell Plant Dry Fly Ash Landfill Boundary



Attachment B

Plot Plan

GENERAL NOTES

1. WORK THIS DRAWING WITH KAMMER PLANT DRAWING 1-5030.

FOR CHANGES RELATED TO THE CCR AND ELG PROJECT, WORK THIS DRAWING WITH THE FOLLOWING REFERENCES:

12-507201	GENERAL ARRANGMENT POND AREA PLAN	1-507200	EQUIPMENT SETTING PLAN UNIT 1 BOTTOM ASH AREA
12-508200	GENERAL ARRANGMENT WASTEWATER TREATMENT BUILDING ENLARGED PLAN	1-507202	EQUIPMENT SETTING PLAN BOTTOM ASH BUNKER AREA
0-300004	POND CLOSURE AND REPURPOSING COVER SHEET AND DRAWING INDEX	2-507200	EQUIPMENT SETTING PLAN UNIT 2 BOTTOM ASH AREA

NOTES:

1. BACKGROUND SHOWN IS FROM EXISTING AERIAL SURVEY GEO ONE DRAWING 01-0340, SHEET 1 OF 1, DATED 4-13-01, TITLED AEP MITCHELL PLANT.

LEGEND:

1 SCR REACTORS
2 UREA TO AMMONIA SYSTEM
3 UNIT 1 FGD ABSORBER
4 UNIT 2 FGD ABSORBER
5 ID FANS
6 FGD BUILDING
7 LIMESTONE PREPARATION BUILDING
8 GYPSUM DEWATERING BUILDING
9 GYPSUM EMERGENCY STACKOUT PILE
10 FGD AUXILIARY TRANSFORMERS
11 FGD SUBSTATION
12 ELEVATED WET PRECIPITATORS (FUTURE)
13 CEMS BUILDINGS (IN STACK UNDER FLUES)
14 FUTURE MERCURY REMOVAL BAGHOUSE & BOOSTER FANS
15 LIMESTONE PILE
16 GYPSUM STORAGE BUILDING
17 1500 DWT BARGE
18 LIMESTONE SLURRY TANKS
19 LIMESTONE SILOS
20 RECLAIM WATER TANKS
21 HYDROCLONE FEED TANKS
22 SERVICE WATER TANKS
23 MAINTENANCE SLURRY STORAGE TANK
24 LIMESTONE CONVEYOR
25 GYPSUM CONVEYOR
26 RELOCATED WAREHOUSE (REPLACES EXISTING WAREHOUSE)
27 ADDITIONAL BARGE CELLS
28 OUTAGE TRAILERS AS REQUIRED
29 MAINTENANCE SLURRY BUILDING
30 EMERGENCY QUENCH PUMPS
31 METAL CLEANING TANK (EXISTING)
32 CONSTRUCTION FACILITIES BUILDING
33 PIPE BRIDGE TO UREA AREA
34 SCR SUBSTATION
35 ID FAN ELECTRICAL BUILDING
36 RELOCATED OIL STORAGE
37 RELOCATED ASKAREL COLLECTION TANK
38 FGD STATION SERVICE TRANSFORMERS
39 COAL BLENDING CONVEYOR
40 BARGE UNLOADING/LOADING FACILITY
41 UREA UNLOADING BUILDING
42 UREA ELECTRICAL BUILDING
43 TRUCK WEIGH SCALE (REED MINERALS)
44 LEACH FIELD
45 NEW TRUCK DELIVERY GATE-REMOTELY OPERATED FROM EXISTING GATE HOUSE
46 BELT CONVEYOR
47 OUTAGE TRAILER AREA SHOWER & RESTROOMS
48 CONTAINMENT POND
49 BARGE UNLOADING RAMP
50 BOILER MAINTENANCE CRANE
51 GYPSUM WALLBOARD STORAGE BUILDING
52 SPARE TRANSFORMERS
53 DRY S03 SORBENT INJECTION SYSTEM
54 MATERIALS HANDLING SUB-STATION #2
55 ID FAN OUTLET DUCT DAMPER SEAL AIR FANS
56 AUXILIARY BOILER STACK
57 13.5 kV BRIDGE
58 LIMESTONE RECLAIM TUNNEL
59 BOILER MODS OUTDOOR MCC
60 TEMPORARY CRANE FOR BARGE UNLOADING
61 CPS TREATMENT FACILITY
62 CPS WASTE CONVEYOR
63 CPS WASTE PILE & PAD
64 CPS WASTE TRANSFER HOUSE
65 CONVEYOR 4EW TUNNEL HEATING OIL TANK
66 HYDROGEN BULK STORAGE AND UNLOADING
67 EXISTING FUEL OIL UNLOADING
68 RIVER WATER MAKE-UP PUMP HOUSE
69 EXISTING COAL BARGE UNLOADER
70 EXISTING SEWAGE PLANT
71 WASTEWATER PONDS
72 WASTEWATER TREATMENT BUILDING
73 PRECIPITATOR PARTS WAREHOUSE
74 69KV FISH CREEK SUB-STATION
75 TRACTOR SHED
76 EXISTING DIESEL FUEL STORAGE TANK (BURIED)
77 HEAVY EQUIPMENT STORAGE BUILDING
78 DELUGE VALVE BUILDING
79 COAL BLENDING SYSTEM ELECTRICAL VAULT
80 EXISTING CONSOL TRANSFER STATION #1
81 EXISTING CONSOL CONVEYOR 31 (NOT IN USE)
82 EXISTING CONVEYOR 1 (NOT IN USE)
83 STATION HTS-3
84 STATION HTS-2B
85 STATION HTS-2A
86 TRANSFER HOUSE
87 COAL BLENDING SYSTEM ELECTRICAL ROOM
88 RECLAIM TUNNEL
89 ST-1 STACKING TUBE
90 HIGH SULFUR COAL SHORT-TERM ACTIVE PILE
91 HIGH SULFUR COAL LONG-TERM STORAGE
92 EXISTING CONSOL CONVEYOR C-3100
93 R-9 RADIAL STACKER
94 EXISTING CONVEYOR #64 TO KAMMER
95 HSC-3 DRIVE/ GTU TOWER
96 HFB-1 FEEDER/ BREAKER
97 FEED RECEIVER HOPPER
98 SCALE TEST PILE
99 STA. R1
100 FUEL OIL STORAGE TANKS
101 345 KV OVERHEAD LINES AND UNIT 2 TOWER
102 CLEARWELL POND
103 EXISTING STACK
104 CONDENSATE TANKS
105 FUTURE EXPANSION
106 UTILITY SHOWER BLDG.
107 WAREHOUSES
108 UNIT 2 OVERFLOW SUMP
109 ACTIVE COAL PILE
110 138 KV UNDERGROUND LINES FROM KAMMER
111 LOW SULFUR COAL LONG TERM STORAGE
112 UNIT 1 OVERFLOW SUMP
113 TRAINING CENTER
114 MAIN GATE HOUSE (GATE 3)
115 CONTROL ROOM SIMULATOR BUILDING
116 FGD STACK - ℄ @ N 10,015, E 10,304
117 BLACK BEAUTY PLANT
118 COOLING TOWER CHEMICAL INJECTION TANKS & PUMPS
119 UNIT 1&2 BLACK START DIESEL GENERATOR AND PDC BUILDING
120 FGD BLACK START DIESEL GENERATOR AND PDC BUILDING
121 GATE 4 GUARD HOUSE
122 POND ENHANCEMENT AREA
123 TEMPORARY TREATMENT AREA
124 UNIT 1 TRANSFER TOWER
125 UNIT 12 COMMON SICON CONVEYOR
126 UNIT 2 TRANSFER TOWER
127 UNIT 12 BOTTOM ASH BUNKER
128 UNIT 12 BOTTOM ASH BUNKER LOADING PAD

ISSUED FOR REVIEW
UPDATED FOR CCR/ELG PROJECT
(A6-C7, E8, F3-F5, H5-K4, J8)

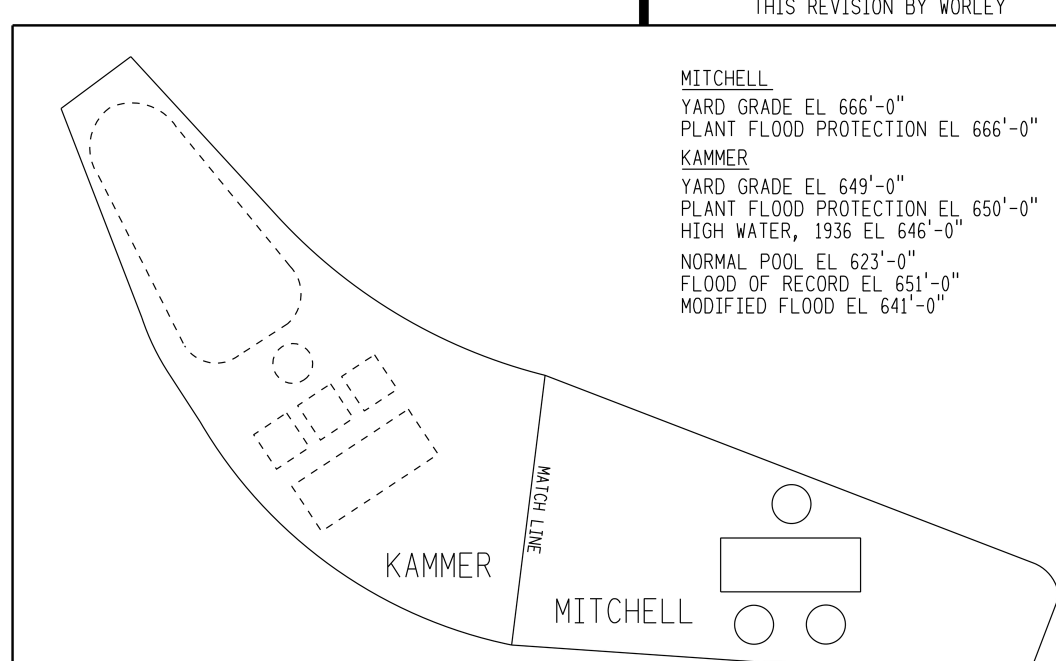
REV	DATE	DRAWN	CHECKED	REVIEWED	LEAD DESIGNER	ENGINEER/ TECH SPEC	LEAD DISC ENGINEER	PROJ ENGR MANAGER
20B	11/18/21	MTM		CLS	MSC	KL	CLS	TMM

THIS REVISION BY WORLEY

MITCHELL
YARD GRADE EL 666'-0"
PLANT FLOOD PROTECTION EL 666'-0"

KAMMER
YARD GRADE EL 649'-0"
PLANT FLOOD PROTECTION EL 650'-0"
HIGH WATER, 1936 EL 646'-0"

NORMAL POOL EL 623'-0"
FLOOD OF RECORD EL 651'-0"
MODIFIED FLOOD EL 641'-0"



KEY PLAN

DATE	NO.	DESCRIPTION	APPD.
	19	PER PROJECT ID MLP-0-MDI-16-103183: ADDED GATE 4 GUARD HOUSE (H, J9) (K5). QA/QC NO. MI-012017 TRA	TRA KFB DDS JAR TVR

REVISIONS

THIS DRAWING IS CLASSIFIED AS:

AEP CONFIDENTIAL

REFERENCE AEP's CORPORATE INFORMATION SECURITY POLICY

OHIO POWER COMPANY

MITCHELL PLANT

CRESAP — WEST VIRGINIA

GENERAL ARRANGEMENT

PLOT PLAN
MITCHELL SITE

UNIT:	DRAWING NUMBER:	REV:
12	5030	20B

SCALE: 1"=200'-0" — MECHANICAL ENGINEERING

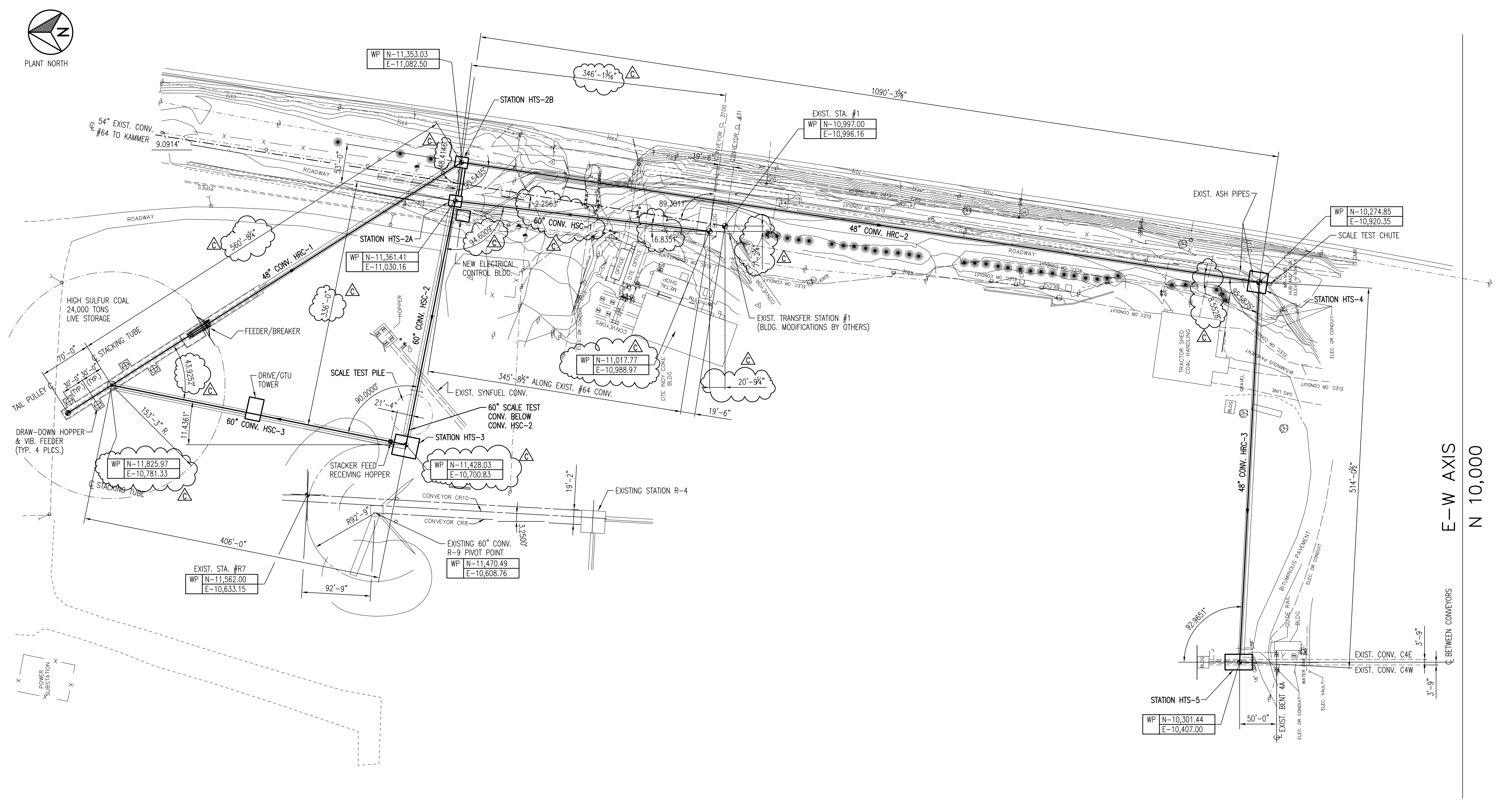
DR:
CH:
SUP:
ENG:
DATE: 8-31-67
APPROVED BY

AMERICAN ELECTRIC POWER

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

PLOT DATE: 11/23/2021
PLOT TIME: 1:29:59 PM
BY: Marc.Miravalles

CROSS REFS:



FOR REVIEW

AMERICAN ELECTRIC POWER
MITCHELL PLANT UNIT 1 & 2
CRESAP, WV.
COAL BLENDING SYSTEM
PARSONS E & C SPECIFICATION AEPM-0-SP-092603
AEP P.O. 849133X181

N-S AXIS
E 10,000

DWG. NO.	REFERENCE DRAWING
L-003	DESIGN CRITERIA & GENERAL NOTES
L-002	FLOW DIAGRAM
L-000	TITLE SHEET & DRAWING LIST

DATE	No.	REVISION	BY
9/2/05	C	REVISED PER SITE VISIT 8/16/05 FOR FINAL CLIENT REVIEW	JLB
8/4/05	B	REVISED LAYOUT PER SITE VISIT	JLB
7/18/01	A	ISSUED FOR CLIENT REVIEW	JLB

RECORD	DATE
TO APPROVAL	7/18/01
TO SHOP	
TO FIELD	
DWN. BY: GLS	7/25/05
CHK. BY: CJS	7/26/05
APP. BY:	

JOB NO. 05-7680

DEARBORN MID-WEST CONVEYOR CO.

THIS DRAWING IN DESIGN AND DETAIL IS OUR PROPERTY AND MUST NOT BE USED EXCEPT IN CONNECTION WITH OUR WORK. ALL RIGHTS OF DESIGN AND DETAIL ARE RESERVED.

PLOT PLAN

MITCHELL PLANT UNITS 1 & 2 – COAL BLENDING SYSTEM

SCALE 1"=60'-0" | DWG. NO. L-001 | REV. NO. C

FILE NAME: G:\0521\L-001.dwg

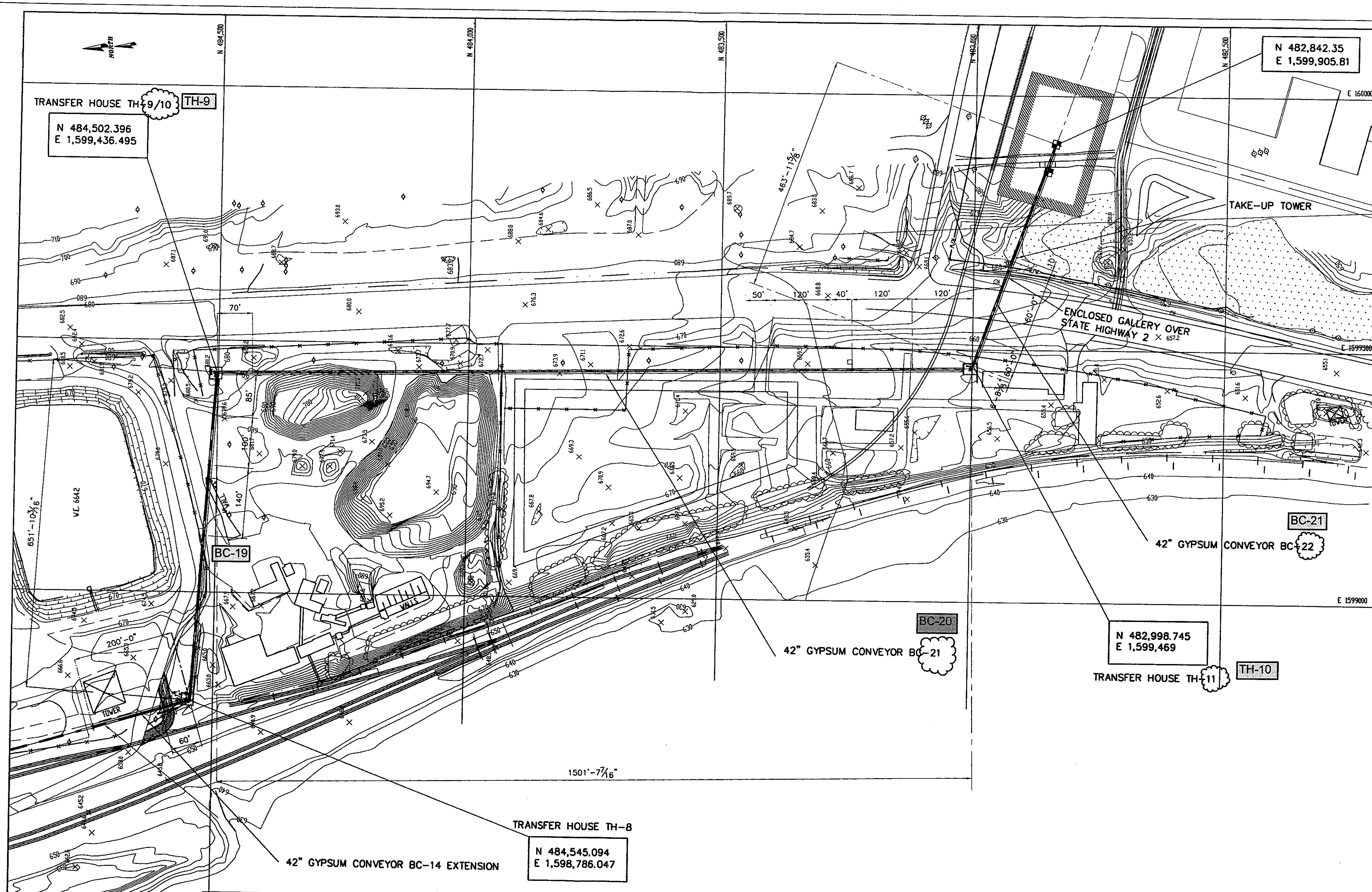
PLOTTED: (JLB) 02-SEP-2005 13:01

PLOT SCALE:

SCALE OF BORDER:

PLOT DATE & TIME:

C.A.D. No.: .DWG



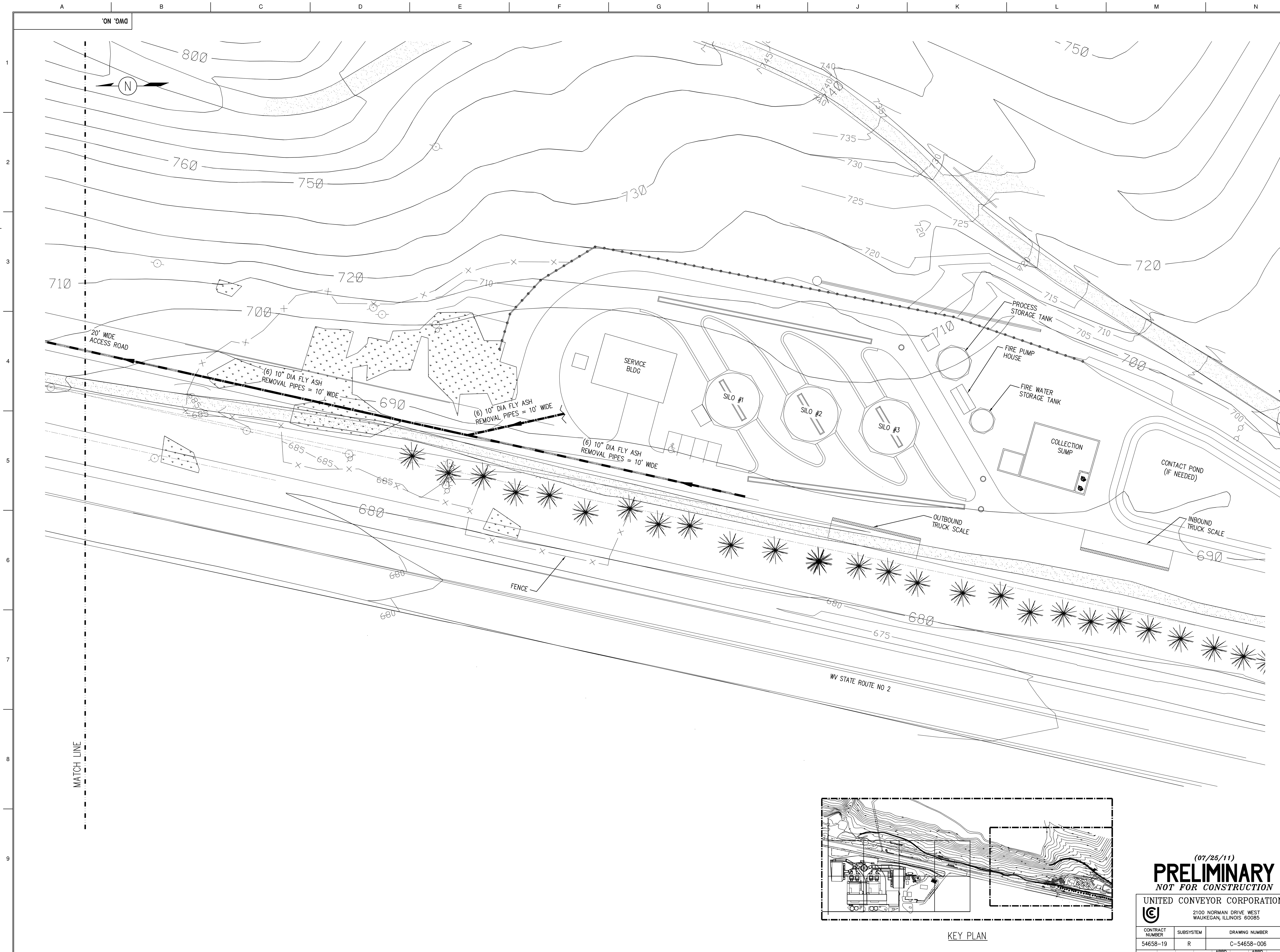
REV.	DATE	DESCRIPTION OF REVISION
2	12-15-05	REVISED TRANSFER TOWER 11
1	12-07-05	ADDED W.P. LOCATIONS

ROBERTS & SCHAEFER Company
ENGINEERS AND CONTRACTORS
CHICAGO – SALT LAKE CITY

PLOT PLAN
GYPSUM HANDLING SYSTEM
OHIO POWER COMPANY
AEP MITCHELL PLANT, CRESAP, WEST VIRGINIA

MADE BY: ARMSTRONG
SCALE: 1" = 80'
DATE: 12-02-05
DRAWING No. 05095-60
REV. 2


DWG. NO.
N
730
760
750
810
820
800
720
740
710
700
690
WV ROUTE 2
TRANSFER STATION
EXHAUSTERS & COMPRESSORS
PDC
MAIN PDC
TRANSFORMERS
EXISTING STACK
UNIT 2 PRECIP.
FLY ASH
ECONOMIZER ASH
UNIT 2 BOILER BLDG.
UNIT 1 BOILER BLDG.
UNIT 2 TURBINE BLDG.
UNIT 1 TURBINE BLDG.
EXHAUSTERS & COMPRESSORS
UNIT 1 PRECIP.
FLY ASH
TRANSFER STATION
UNIT 1 OVERFLOW SUMP
PDC
MATCH LINE
E 10,000
E 10,000
KEY PLAN
(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST
WAUKEGAN, ILLINOIS 60085
CONTRACT NUMBER 54658-19
SUBSYSTEM R
DRAWING NUMBER C-54658-004
DSGN MAM
CHKD –
APPD (ENGR) –
APPD (PROJ) –
GENERAL NOTES
REFERENCE DRAWINGS
07/25/11 A ISSUED FOR CONCEPTUAL REVIEW TMW
REVISIONS
" THIS DRAWING IS THE PROPERTY OF THE AMERICAN ELECTRIC POWER SERVICE CORP. AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT THE WRITTEN CONSENT OF THE AEP SERVICE CORP. ,OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST, AND IS TO BE RETURNED UPON REQUEST "
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNIT 1 & 2
FLY ASH REMOVAL SYSTEM
SITE PLAN
DWG. NO.
SCALE: 1/32"=1'-0"
MECHANICAL ENGINEERING DIVISION
DR: MAM
CH:
ENGR:
PROJ ENGR:
DATE: 7/23/2011
APPROVED BY
AEP AMERICAN ELECTRIC POWER
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215
IGS0700
Rev. No: .
Plot Date: .
Plotted by: .



(07/25/11)

PRELIMINARY

NOT FOR CONSTRUCTION

UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST
WAUKEGAN, ILLINOIS 60085

CONTRACT NUMBER	SUBSYSTEM	DRAWING NUMBER
54658–19	R	C–54658–006

DSGN MAM | CHKD – | APPD (ENGR) – | APPD (PROJ) –

REVISIONS

OHIO POWER COMPANY

MITCHELL PLANT

CRESAP WEST VIRGINIA

DRY FLY ASH CONVERSION
UNIT 1 & 2
FLY ASH REMOVAL SYSTEM
SITE PLAN

DWG. NO.

SCALE: 1/32"=1'-0"
DR: MAM
CH:
APPROVED BY
DATE: 7/23/2011

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

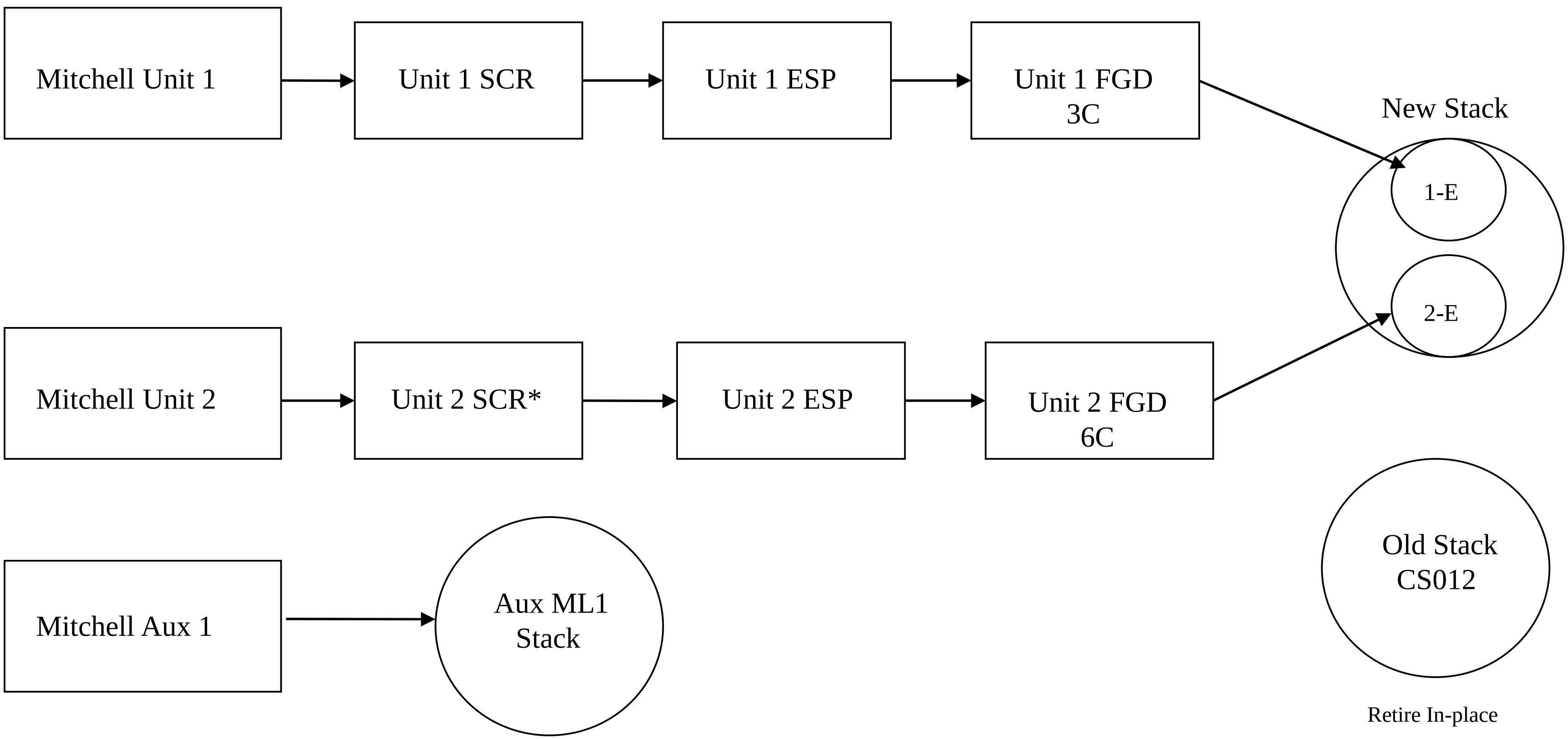
Rev. No: .
Plot Date: .
Plotted by: .

IGS0700

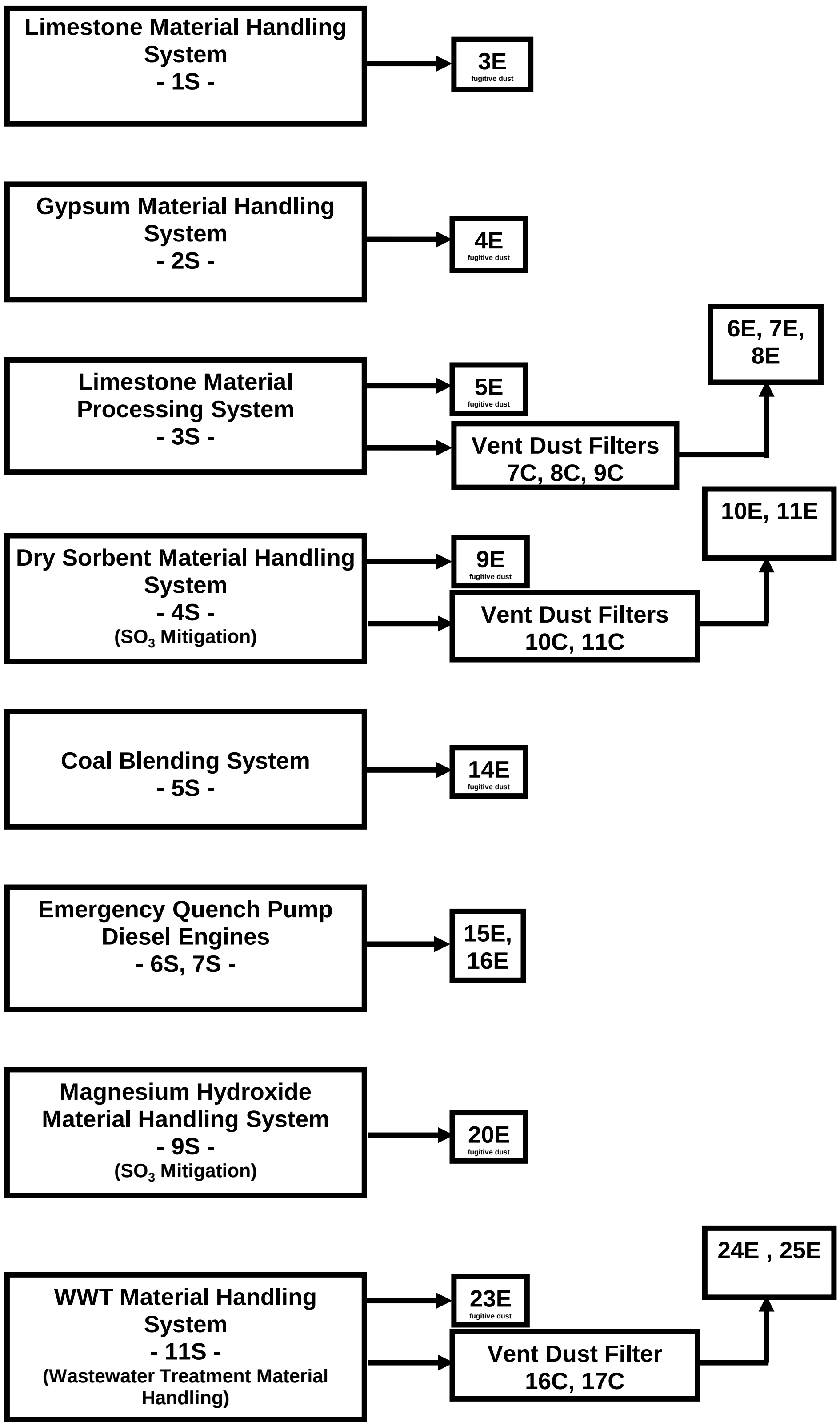
Attachment C

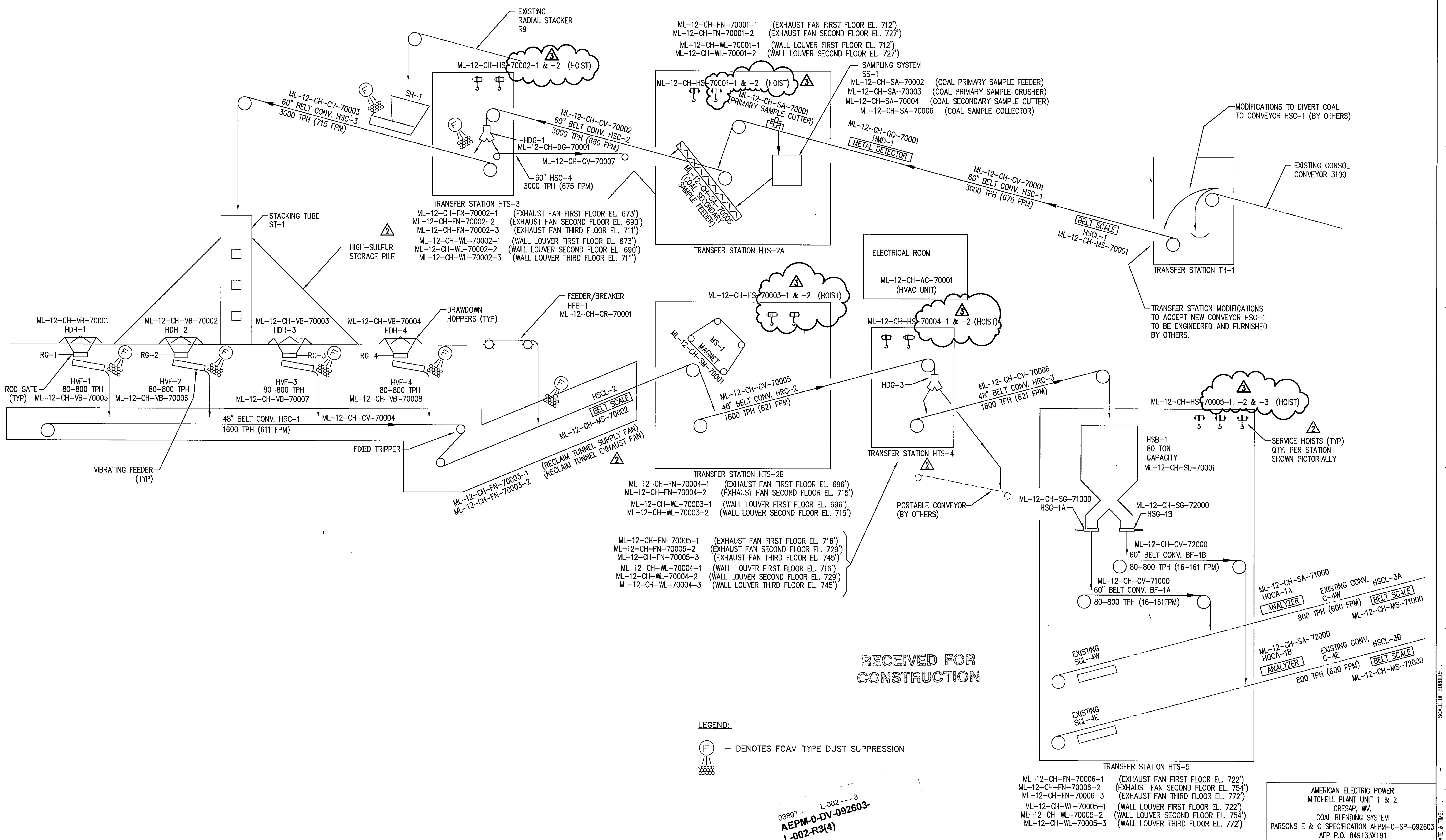
Process Flow Diagrams

Flow Diagram:
Steam Generator and Associated Pollution Control Equipment



Process Flow Diagrams





AMERICAN ELECTRIC POWER
MITCHELL PLANT UNIT 1 & 2
CRESAP, WV.
COAL BLENDING SYSTEM
PARSONS E & C SPECIFICATION AEPM-0-SP-092603
AEP P.O. 849133X181

				RECORD	DATE
				TO APPROVAL	11-7-05
				TO SHOP	.
				TO FIELD	.
9-23-06	3	REVISED HOIST TAG NUMBERS	JLB		
4/20/06	2	CORRECTED CALL OUTS ADDED HOIST NOTE	JLB	DWN. BY: GLS	06/28/05
2/28/06	1	ADDED EQUIPMENT TAG NOS.	JLB	CHK. BY: JLB	9/15/05
12/21/05	0	ISSUED FOR CONSTRUCTION	JLB	APP. BY: .	
11/7/05	A	ISSUED FOR CLIENT REVIEW	JLB		
DATE	No.	REVISION	BY	JOB NO. 05-7680	

DMW
DEARBORN MID-WEST CONVEYOR CO.

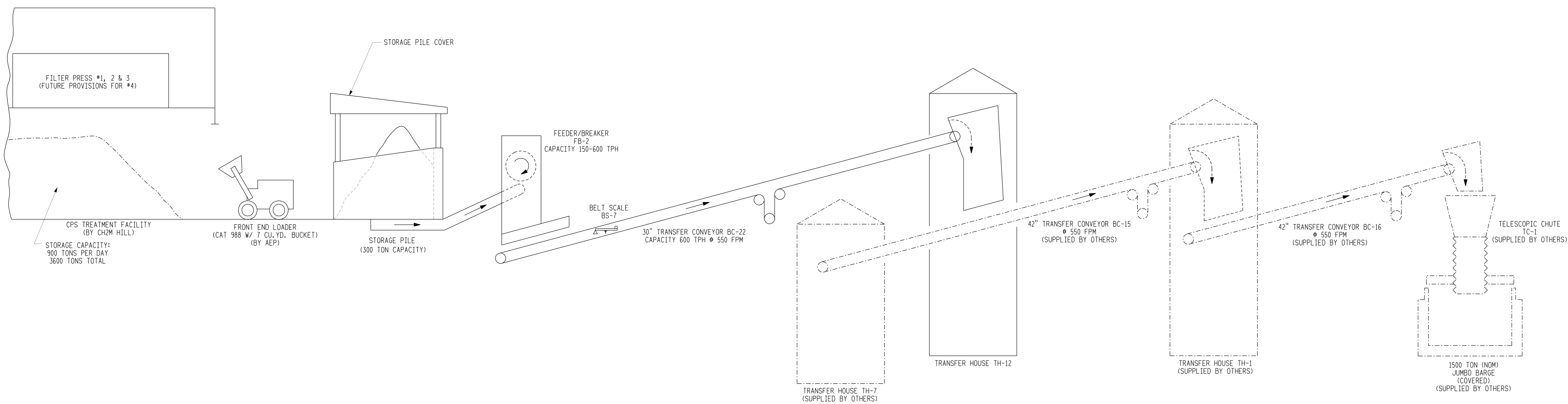
FLOW DIAGRAM

MITCHELL PLANT UNITS 1 & 2 – COAL BLENDING SYSTEM

SCALE NONE | DWG. NO. L-002 | REV. NO. 3

FILE NAME: G:\0521\L-002.dwg
PLOTTED: (JLB) 23-SEP-2006 10:59
PLOT SCALE:
SCALE OF BORDER:
PLOT DATE & TIME:
C.A.D. No.: DWG

DWG. NO. AEPM-12-SK-ZU-302-004



REVISED STORAGE PILE COVER
ISSUED FOR PERMITTING

REV	DATE	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER/ TECH SPEC	LEAD DISC ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
B	01/20/06	CH			TDH	SGW	JFW	CWS
A	12/22/05	MT			TDH	SGW	JFW	CWS

ISSUED FOR PERMITTING (Rev. A)

DATE | NO. | DESCRIPTION | APPD.

REVISIONS

PARSONS E&C

PRELIMINARY STATUS — DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
LDE SG WAINWRIGHT 12-22-05

APPROVED STATUS — DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
LDE

ORIGINATING PERSONNEL
DRAWN BY: MT
CHECKED BY:
LEAD DESIGNER: CC HAGEMEYER
ENGINEER/TECH SPECIALIST: T HAUSCHILD
PROJECT ENGINEERING MANAGER: JF WAGNER
PROJECT MANAGER: CW SAMUELSON

PROFESSIONAL ENGINEER'S SEAL
ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE:______________ STATE:_______
LIC. NO.:__________ DATE:________

OHIO POWER COMPANY
MITCHELL PLANT
CRESAP WEST VIRGINIA

FLOW DIAGRAM
CHLORIDE PURGE STREAM
FILTER CAKE HANDLING

DWG. NO. AEPM-12-SK-QW-302-001-B

SCALE: NONE
DR: JG
CH:
DATE:
APPROVED BY

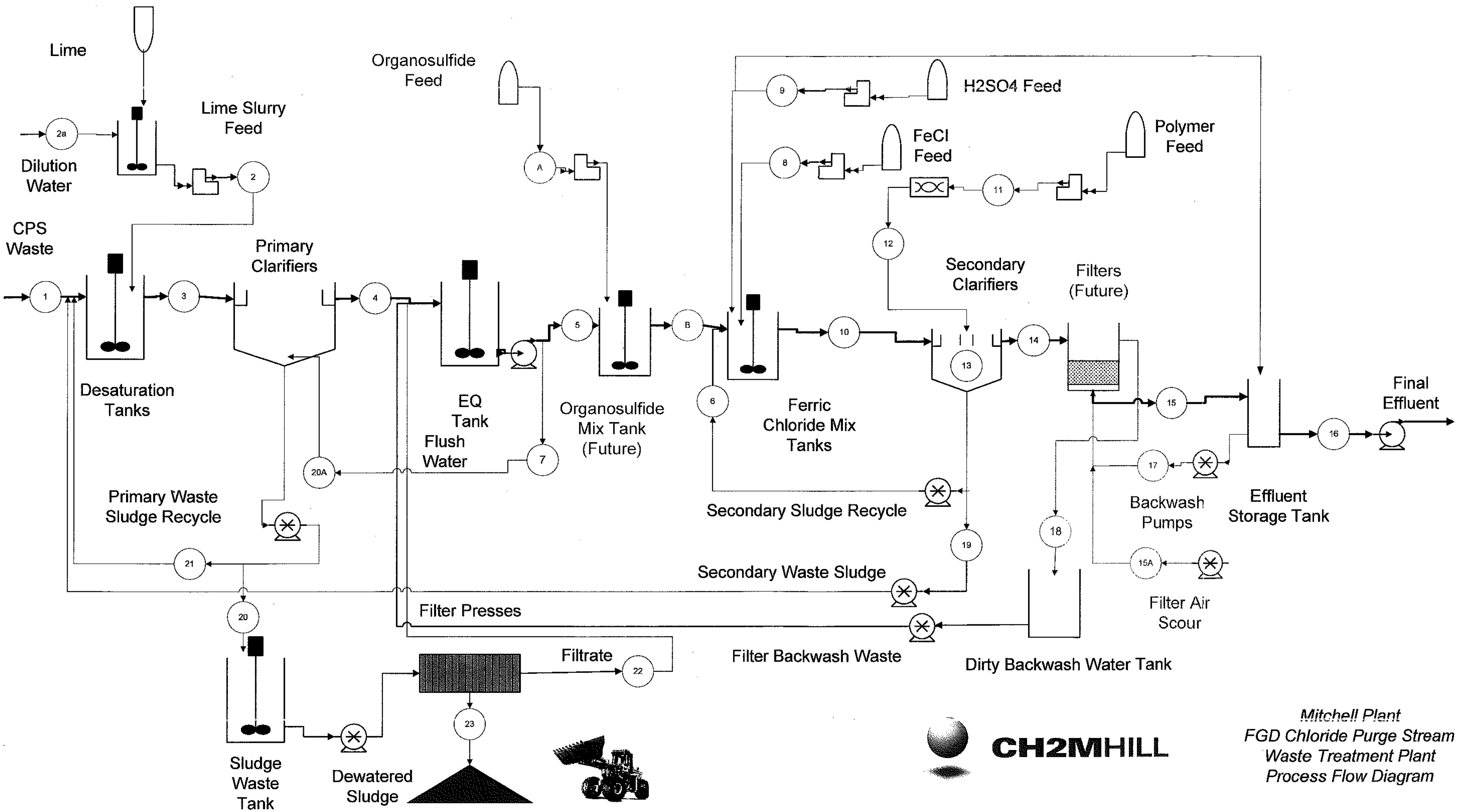
DOCUMENT PREPARED BY PARSONS E&C

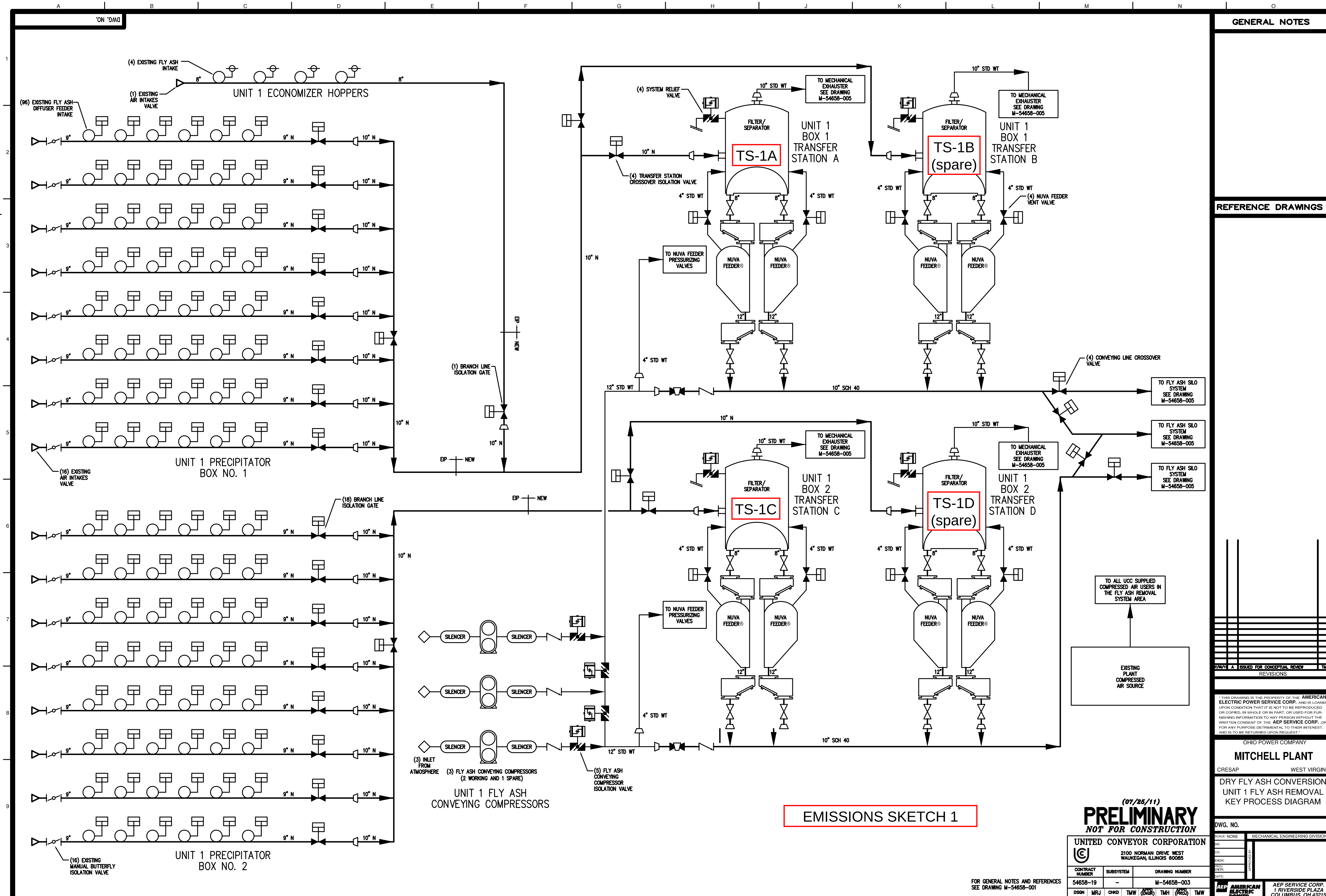
AMERICAN ELECTRIC POWER

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

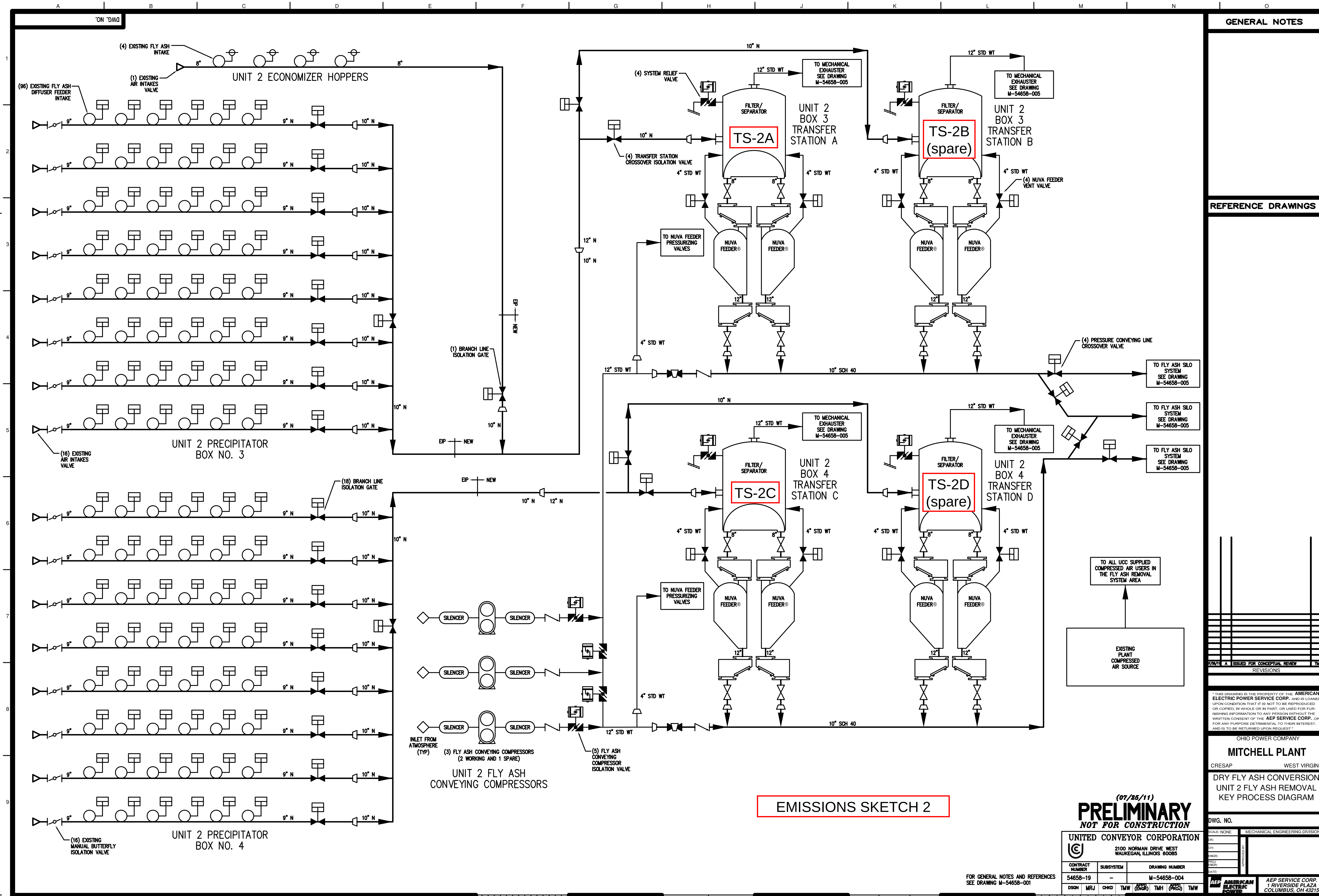
IGS0694
PE&C-FILE: aepmG3d.sed
PE&C-DATE: 04-Mar-04 07:55
SYSTEM DATE-DD-MMM-YYYY
SYSTEM TIME-HOUR:MINUTE

Attachment 1. FGD CPS Wastewater Treatment System Process Flow Diagram

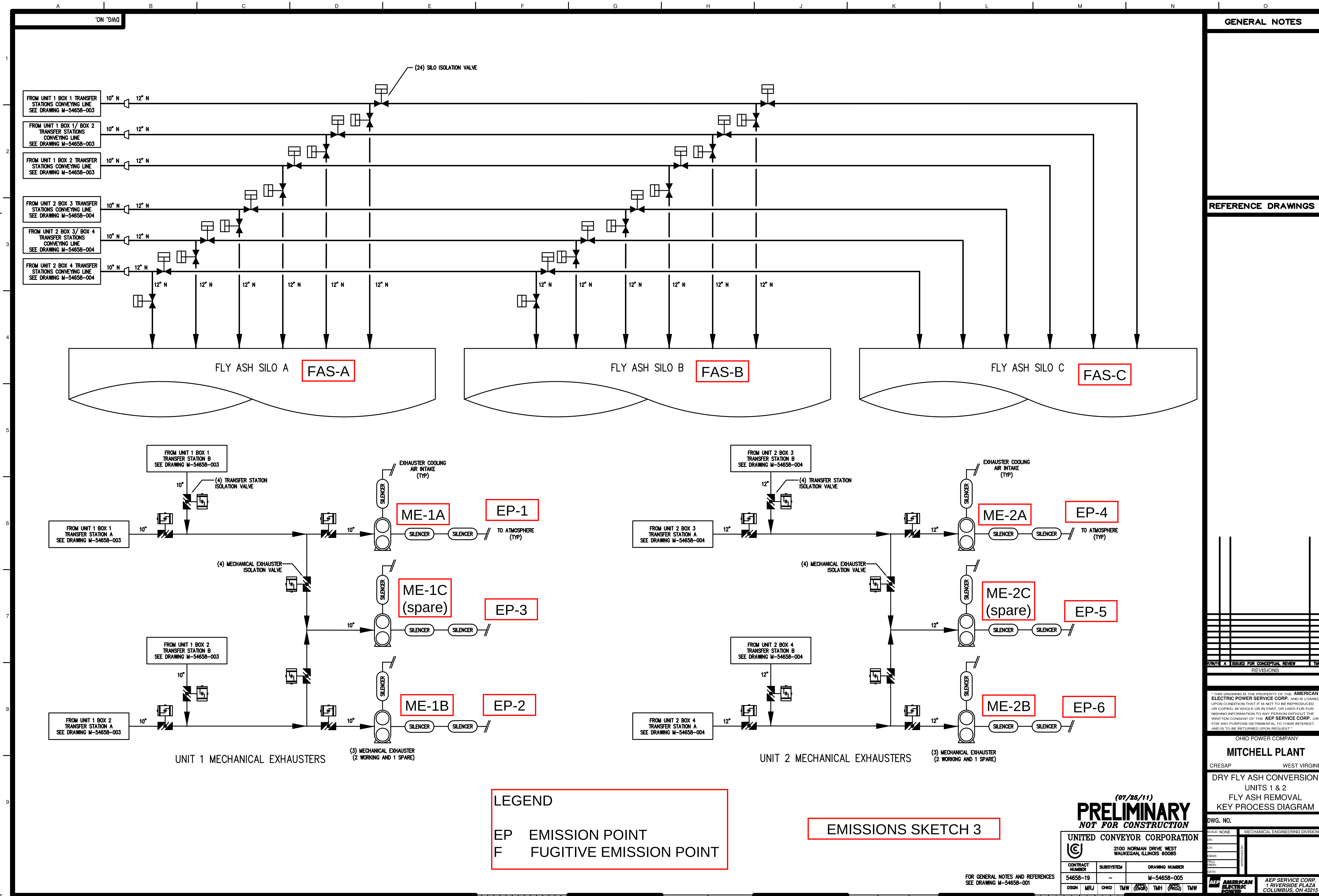




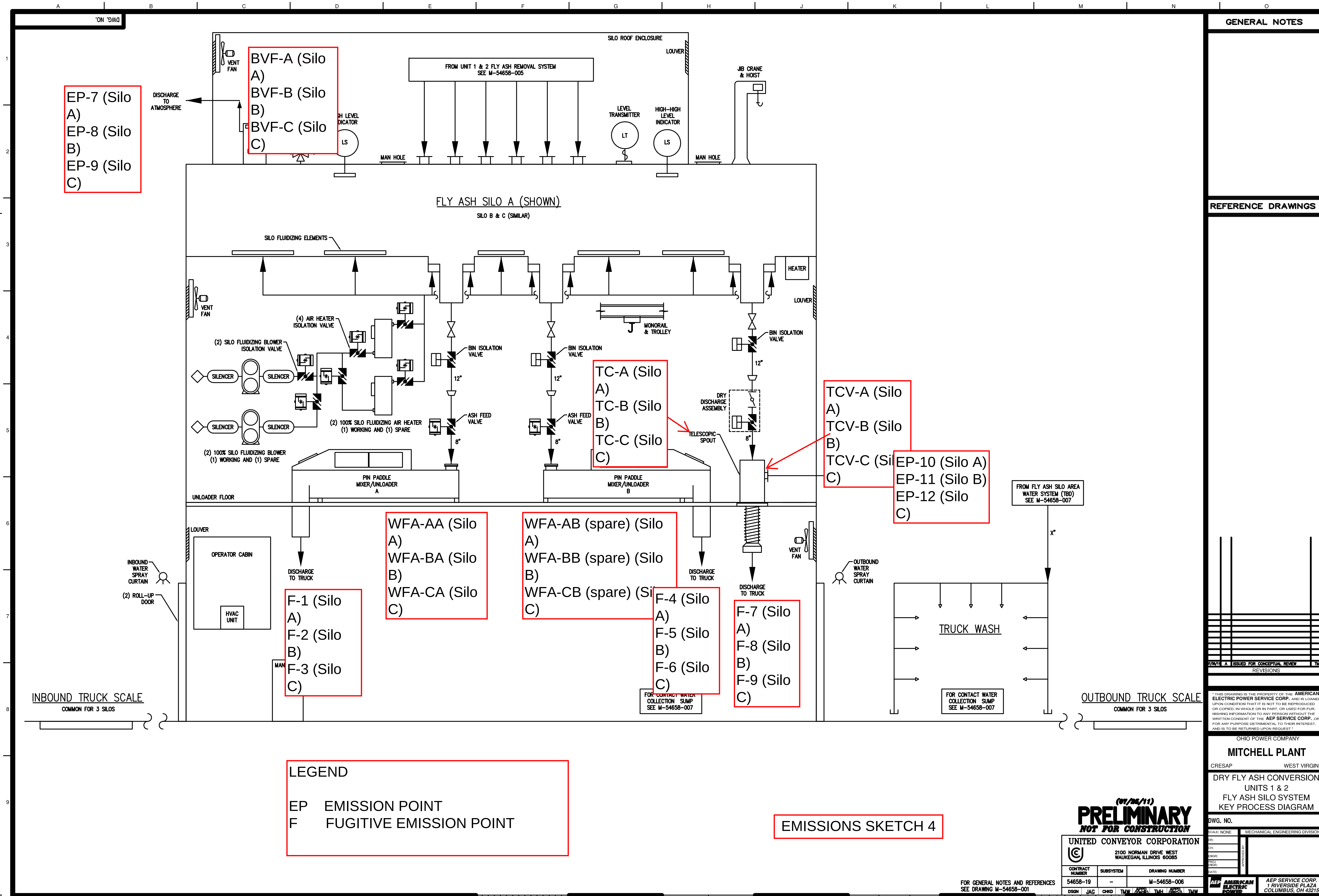
GENERAL NOTES
REFERENCE DRAWINGS
UNIT 1 ECONOMIZER HOPPERS
(4) EXISTING FLY ASH INTAKE
(1) EXISTING AIR INTAKES VALVE
(96) EXISTING FLY ASH DIFFUSER FEEDER INTAKE
UNIT 1 PRECIPITATOR BOX NO. 1
(16) EXISTING AIR INTAKES VALVE
(1) BRANCH LINE ISOLATION GATE
(18) BRANCH LINE ISOLATION GATE
UNIT 1 PRECIPITATOR BOX NO. 2
(16) EXISTING MANUAL BUTTERFLY ISOLATION VALVE
(4) SYSTEM RELIEF VALVE
(4) TRANSFER STATION CROSSOVER ISOLATION VALVE
TO MECHANICAL EXHAUSTER SEE DRAWING M-54658-005
FILTER/ SEPARATOR
TS-1A
UNIT 1 BOX 1 TRANSFER STATION A
TS-1B (spare)
UNIT 1 BOX 1 TRANSFER STATION B
(4) NUVA FEEDER VENT VALVE
TO NUVA FEEDER PRESSURIZING VALVES
NUVA FEEDER®
10" SCH 40
(4) CONVEYING LINE CROSSOVER VALVE
TO FLY ASH SILO SYSTEM SEE DRAWING M-54658-005
TS-1C
UNIT 1 BOX 2 TRANSFER STATION C
TS-1D (spare)
UNIT 1 BOX 2 TRANSFER STATION D
TO ALL UCC SUPPLIED COMPRESSED AIR USERS IN THE FLY ASH REMOVAL SYSTEM AREA
EXISTING PLANT COMPRESSED AIR SOURCE
SILENCER
(3) INLET FROM ATMOSPHERE
(3) FLY ASH CONVEYING COMPRESSORS (2 WORKING AND 1 SPARE)
UNIT 1 FLY ASH CONVEYING COMPRESSORS
(5) FLY ASH CONVEYING COMPRESSOR ISOLATION VALVE
EMISSIONS SKETCH 1
(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST WAUKEGAN, ILLINOIS 60085
CONTRACT NUMBER 54658-19
DRAWING NUMBER M-54658-003
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
ISSUED FOR CONCEPTUAL REVIEW
REVISIONS
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNIT 1 FLY ASH REMOVAL
KEY PROCESS DIAGRAM
DWG. NO.
MECHANICAL ENGINEERING DIVISION
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215



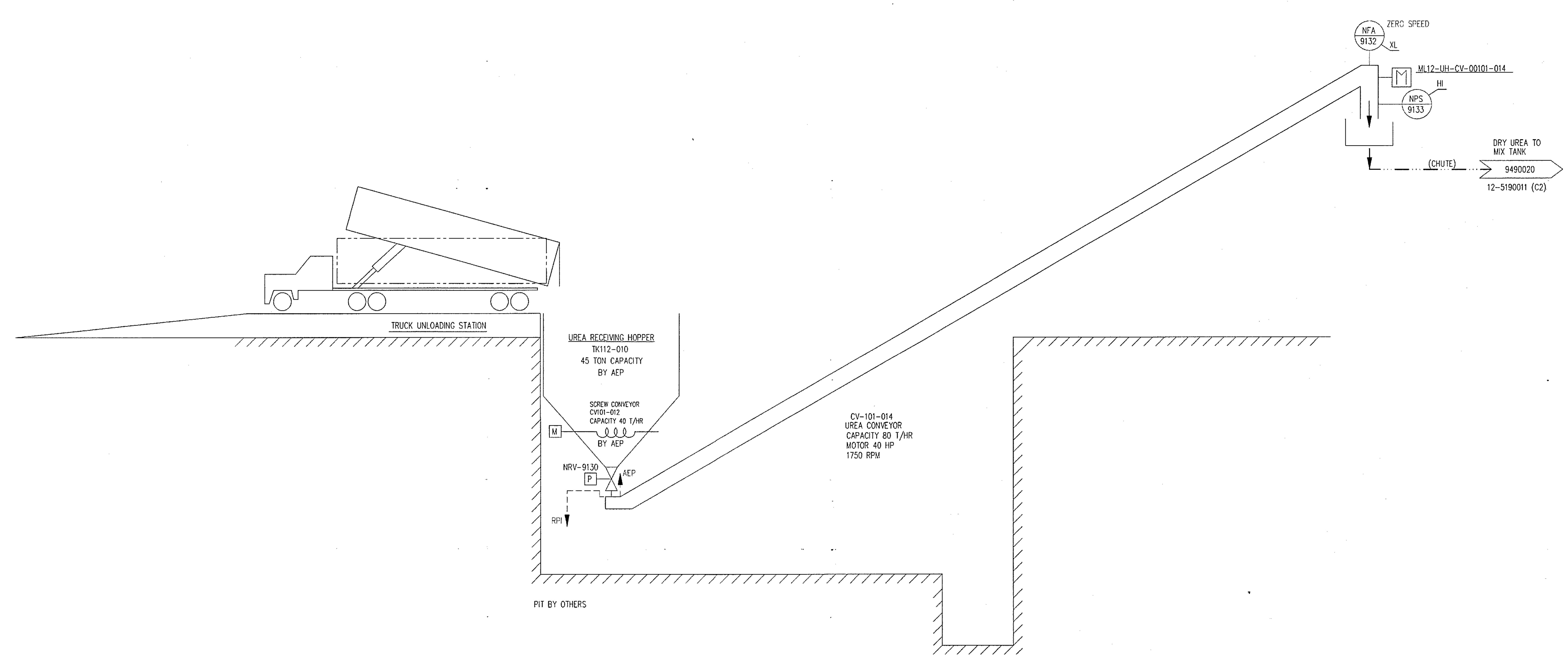
UNIT 2 ECONOMIZER HOPPERS
(4) EXISTING FLY ASH INTAKE
(1) EXISTING AIR INTAKES VALVE
(96) EXISTING FLY ASH DIFFUSER FEEDER INTAKE
UNIT 2 PRECIPITATOR BOX NO. 3
(16) EXISTING AIR INTAKES VALVE
(1) BRANCH LINE ISOLATION GATE
(18) BRANCH LINE ISOLATION GATE
UNIT 2 PRECIPITATOR BOX NO. 4
(16) EXISTING MANUAL BUTTERFLY ISOLATION VALVE
(4) SYSTEM RELIEF VALVE
(4) TRANSFER STATION CROSSOVER ISOLATION VALVE
TO MECHANICAL EXHAUSTER SEE DRAWING M-54658-005
FILTER/ SEPARATOR
TS-2A
UNIT 2 BOX 3 TRANSFER STATION A
TS-2B (spare)
UNIT 2 BOX 3 TRANSFER STATION B
TS-2C
UNIT 2 BOX 4 TRANSFER STATION C
TS-2D (spare)
UNIT 2 BOX 4 TRANSFER STATION D
NUVA FEEDER®
(4) NUVA FEEDER VENT VALVE
TO NUVA FEEDER PRESSURIZING VALVES
(4) PRESSURE CONVEYING LINE CROSSOVER VALVE
TO FLY ASH SILO SYSTEM SEE DRAWING M-54658-005
TO ALL UCC SUPPLIED COMPRESSED AIR USERS IN THE FLY ASH REMOVAL SYSTEM AREA
EXISTING PLANT COMPRESSED AIR SOURCE
SILENCER
INLET FROM ATMOSPHERE (TYP)
(3) FLY ASH CONVEYING COMPRESSORS (2 WORKING AND 1 SPARE)
(5) FLY ASH CONVEYING COMPRESSOR ISOLATION VALVE
UNIT 2 FLY ASH CONVEYING COMPRESSORS
EMISSIONS SKETCH 2
GENERAL NOTES
REFERENCE DRAWINGS
REVISIONS
ISSUED FOR CONCEPTUAL REVIEW
"THIS DRAWING IS THE PROPERTY OF THE AMERICAN ELECTRIC POWER SERVICE CORP. AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT THE WRITTEN CONSENT OF THE AEP SERVICE CORP., OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST. AND IS TO BE RETURNED UPON REQUEST."
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNIT 2 FLY ASH REMOVAL
KEY PROCESS DIAGRAM
(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST
WAUKEGAN, ILLINOIS 60085
CONTRACT NUMBER 54658-19
DRAWING NUMBER M-54658-004
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
DWG. NO.
MECHANICAL ENGINEERING DIVISION
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215



GENERAL NOTES
REFERENCE DRAWINGS
(24) SILO ISOLATION VALVE
FROM UNIT 1 BOX 1 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-003
FROM UNIT 1 BOX 1/ BOX 2 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-003
FROM UNIT 1 BOX 2 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-003
FROM UNIT 2 BOX 3 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-004
FROM UNIT 2 BOX 3/ BOX 4 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-004
FROM UNIT 2 BOX 4 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-004
10" N
12" N
FLY ASH SILO A
FAS-A
FLY ASH SILO B
FAS-B
FLY ASH SILO C
FAS-C
FROM UNIT 1 BOX 1 TRANSFER STATION B SEE DRAWING M-54658-003
FROM UNIT 1 BOX 1 TRANSFER STATION A SEE DRAWING M-54658-003
FROM UNIT 1 BOX 2 TRANSFER STATION B SEE DRAWING M-54658-003
FROM UNIT 1 BOX 2 TRANSFER STATION A SEE DRAWING M-54658-003
(4) TRANSFER STATION ISOLATION VALVE
(4) MECHANICAL EXHAUSTER ISOLATION VALVE
EXHAUSTER COOLING AIR INTAKE (TYP)
SILENCER
TO ATMOSPHERE (TYP)
ME-1A
EP-1
ME-1C (spare)
EP-3
ME-1B
EP-2
(3) MECHANICAL EXHAUSTER (2 WORKING AND 1 SPARE)
UNIT 1 MECHANICAL EXHAUSTERS
FROM UNIT 2 BOX 3 TRANSFER STATION B SEE DRAWING M-54658-004
FROM UNIT 2 BOX 3 TRANSFER STATION A SEE DRAWING M-54658-004
FROM UNIT 2 BOX 4 TRANSFER STATION B SEE DRAWING M-54658-004
FROM UNIT 2 BOX 4 TRANSFER STATION A SEE DRAWING M-54658-004
ME-2A
EP-4
ME-2C (spare)
EP-5
ME-2B
EP-6
UNIT 2 MECHANICAL EXHAUSTERS
LEGEND
EP EMISSION POINT
F FUGITIVE EMISSION POINT
EMISSIONS SKETCH 3
(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST WAUKEGAN, ILLINOIS 60085
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
CONTRACT NUMBER 54658-19
DRAWING NUMBER M-54658-005
REVISIONS
A ISSUED FOR CONCEPTUAL REVIEW
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNITS 1 & 2
FLY ASH REMOVAL
KEY PROCESS DIAGRAM
DWG. NO.
MECHANICAL ENGINEERING DIVISION
AMERICAN ELECTRIC POWER
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215


EP-7 (Silo A)
EP-8 (Silo B)
EP-9 (Silo C)
DISCHARGE TO ATMOSPHERE
VENT FAN
BVF-A (Silo A)
BVF-B (Silo B)
BVF-C (Silo C)
SILO ROOF ENCLOSURE
LOUVER
FROM UNIT 1 & 2 FLY ASH REMOVAL SYSTEM SEE M-54658-005
JIB CRANE & HOIST
LEVEL TRANSMITTER
HIGH-HIGH LEVEL INDICATOR
MAN HOLE
FLY ASH SILO A (SHOWN)
SILO B & C (SIMILAR)
SILO FLUIDIZING ELEMENTS
HEATER
(4) AIR HEATER ISOLATION VALVE
(2) SILO FLUIDIZING BLOWER ISOLATION VALVE
SILENCER
BIN ISOLATION VALVE
MONORAIL & TROLLEY
TC-A (Silo A)
TC-B (Silo B)
TC-C (Silo C)
TCV-A (Silo A)
TCV-B (Silo B)
TCV-C (Silo C)
EP-10 (Silo A)
EP-11 (Silo B)
EP-12 (Silo C)
DRY DISCHARGE ASSEMBLY
TELESCOPIC SPOUT
ASH FEED VALVE
(2) 100% SILO FLUIDIZING AIR HEATER (1) WORKING AND (1) SPARE
(2) 100% SILO FLUIDIZING BLOWER (1) WORKING AND (1) SPARE
PIN PADDLE MIXER/UNLOADER A
PIN PADDLE MIXER/UNLOADER B
UNLOADER FLOOR
FROM FLY ASH SILO AREA WATER SYSTEM (TBD) SEE M-54658-007
WFA-AA (Silo A)
WFA-BA (Silo B)
WFA-CA (Silo C)
WFA-AB (spare) (Silo A)
WFA-BB (spare) (Silo B)
WFA-CB (spare) (Silo C)
OPERATOR CABIN
HVAC UNIT
INBOUND WATER SPRAY CURTAIN
(2) ROLL-UP DOOR
DISCHARGE TO TRUCK
F-1 (Silo A)
F-2 (Silo B)
F-3 (Silo C)
F-4 (Silo A)
F-5 (Silo B)
F-6 (Silo C)
F-7 (Silo A)
F-8 (Silo B)
F-9 (Silo C)
OUTBOUND WATER SPRAY CURTAIN
TRUCK WASH
FOR CONTACT WATER COLLECTION SUMP SEE M-54658-007
INBOUND TRUCK SCALE
COMMON FOR 3 SILOS
OUTBOUND TRUCK SCALE
COMMON FOR 3 SILOS
LEGEND
EP EMISSION POINT
F FUGITIVE EMISSION POINT
EMISSIONS SKETCH 4
GENERAL NOTES
REFERENCE DRAWINGS
ISSUED FOR CONCEPTUAL REVIEW
REVISIONS
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST WAUKEGAN, ILLINOIS 60085
54658-19
M-54658-006
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNITS 1 & 2
FLY ASH SILO SYSTEM
KEY PROCESS DIAGRAM
DWG. NO.
MECHANICAL ENGINEERING DIVISION
AMERICAN ELECTRIC POWER
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

DWG. NO. 100273-9490010



PARSONS E & C
MITCHELL PLANT

✓ REVIEWED AND ACCEPTED
___ REVIEWED AND ACCEPTED AS NOTED (RESUBMIT FOR RECORD)
___ NOT ACCEPTED (RESUBMIT FOR REVIEW)
___ FOR INFORMATION ONLY (REVIEW WAIVED)

THE REVIEW OF THIS SUBMITTAL IS ONLY FOR GENERAL CONFORMANCE WITH THE DESIGN CONCEPTS OF THE PROJECT AND GENERAL COMPLIANCE WITH THE INFORMATION IN THE CONTRACT. THE SUBMITTAL VENDOR IS FULLY RESPONSIBLE FOR; FULL COMPLIANCE WITH THE PROJECT REQUIREMENTS; FOR DIMENSIONS TO BE CONFORMED AND/OR RELATED AT/TO THE JOBSITE; FOR INFORMATION THAT PERTAINS SOLELY TO THE FABRICATION PROCESS; FOR DESIGNS ORIGINATED BY HIM/HER; FOR TECHNIQUES OF CONSTRUCTION AND; FOR COORDINATION OF THE WORK OF ALL TRADES. SUBMITTAL REVIEW DOES NOT CONSTITUTE A CHANGE ORDER AND DOES NOT ALTER ANY CONTRACT TERMS AND CONDITIONS.

DATE 5/31/06 BY [signature]

03158 - 12-5190010 - - - 1
AEPM-12-DV-094502-
12-5190010-R1(6)

NOTES:

1. DELETED
2. ALL TAG #'S PREFACED WITH ML12 UNLESS OTHERWISE SPECIFIED.

LEGEND

STEAM
AMMONIA VAPOR
DRY UREA

ALTERATION	NO.	BY	CHK	DATE	APP'D	DATE
ISSUE FOR CONSTRUCTION	04	JWL	[illegible]	11/17/05	CAE	11/18/05
ISSUE FOR CONSTRUCTION	03	JWL	BH	05/20/05	CAE	05/20/05
ISSUE FOR APPROVAL	02	JWL	TN	04/30/05	CAE	05/01/05
ISSUE FOR CERTIFICATION	01	JWL	TN	04/12/05	BB	04/12/05

"N" MATERIAL NOT FURNISHED BY
"F" MATERIAL FURNISHED BY
RILEY POWER INC.

THIS DRAWING IS NOT APPROVED FOR CONSTRUCTION UNLESS IT CONTAINS DATE AND SIGNATURE OF APPROVAL AND THE COMPANY RESERVES THE RIGHT TO CORRECT ANY ERRORS OR OMISSIONS PRIOR TO ACTUAL START OF WORK.

CLAYTON ERICKSON — RELEASED & APPROVED — 05/20/05 DATE

DRAWN JWL DATE 03/14/05
CHECKED TN DATE 03/15/05
APP'D RJ DATE 03/15/05

FUNCTIONAL REVIEW / APPROVAL
REVIEWED & APP'D / DATE

DO NOT SCALE
USE DIMENSIONS ONLY

SCALE NTS IN. = 1 FT.
ES W F ER

RILEY POWER INC.

PIPING AND INSTRUMENTATION DIAGRAM
DRY UREA UNLOADING
U2A SYSTEM
MITCHELL PLANT – UNIT #1 & 2
AMERICAN ELECTRIC POWER
CRESAP, WEST VIRGINIA

DWG. NO. 100273–9490010–04

DATE	NO.	DESCRIPTION	APPD.
	1	ISSUE FOR CONSTRUCTION	
	0	ISSUE FOR CONSTRUCTION	

REVISIONS

OHIO POWER COMPANY

MITCHELL PLANT

CRESAP — WEST VIRGINIA

FLOW DIAGRAM DRY UREA HANDLING

DWG. NO. 12-5190010 - 1

SCALE: none
DR:
CH:
DES SUPV:
ENGR:
DATE:
APPROVED BY

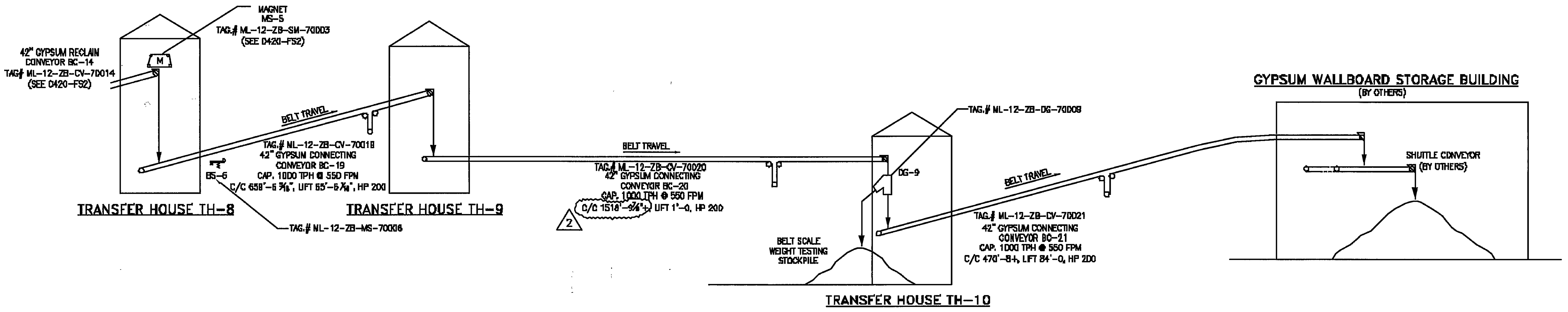
DOCUMENT PREPARED BY RILEY POWER INC.

AEP AMERICAN ELECTRIC POWER

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

NOMENCLATURE

DG-•	DIVERTER GATE
MS-*	SELF CLEANING MAGNETIC SEPARATOR
BS-*	BELT SCALE
BC-#	BELT CONVEYOR



RECEIVED FOR CONSTRUCTION

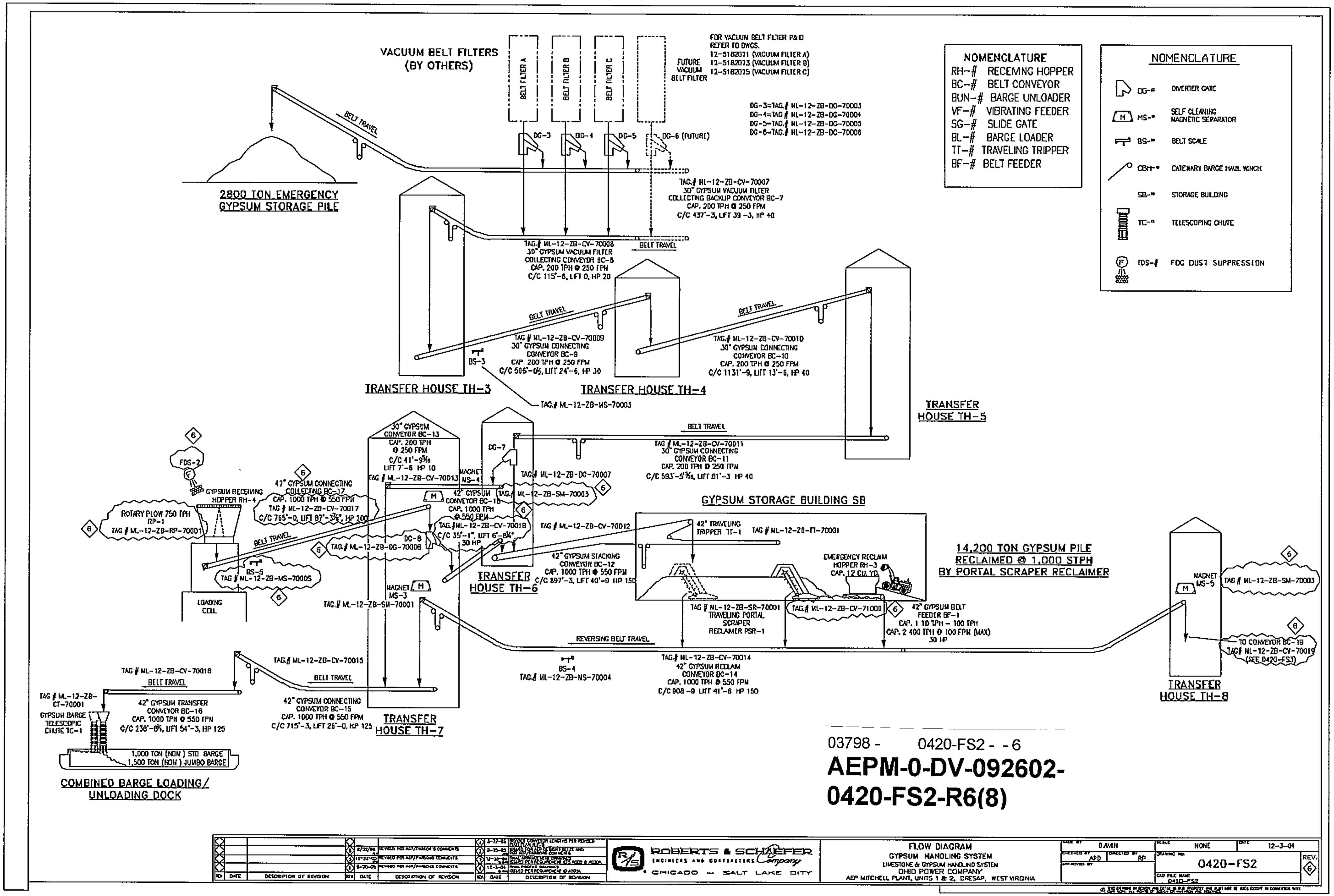
03868 - 0420-FS3 - - - 2
AEPM-0-DV-092604-0420-FS3-R2(3)

REV	DATE	DESCRIPTION OF REVISION
2	9/12/06	REVISED PER CUSTOMER'S COMMENTS
1	8/25/06	REVISED PER AEP/PARSON'S COMMENTS
0	12-22-05	ISSUED FOR APPROVAL

ROBERTS & SCHAEFER Company
ENGINEERS AND CONTRACTORS
CHICAGO — SALT LAKE CITY

FLOW DIAGRAM
GYPSUM HANDLING SYSTEM
LIMESTONE & GYPSUM HANDLING SYSTEM
OHIO POWER COMPANY
AEP MITCHELL PLANT, UNITS 1 & 2, CRESAP, WEST VIRGINIA

MADE BY	A DYDCO
CHECKED BY	FUP
DIRECTED BY	B TURNEY
APPROVED BY	
SCALE	NONE
DATE	12-27-05
DRAWING No.	0420-FS3
REV.	2
CAD FILE NAME	0420-FS3



03798 - 0420-FS2 - -6

AEPM-0-DV-092602-0420-FS2-R6(8)

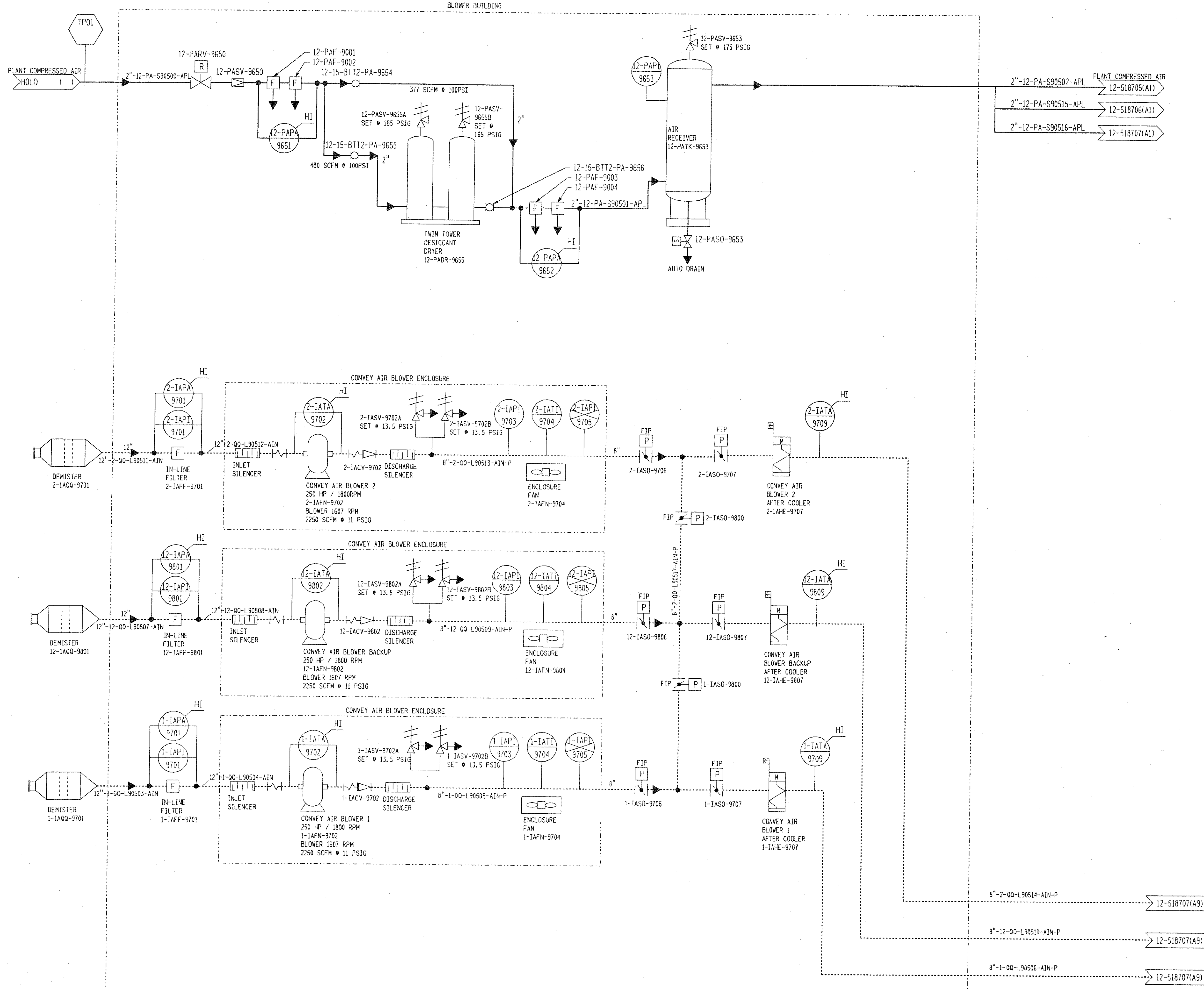
REV	DATE	DESCRIPTION OF REVISION	REV	DATE	DESCRIPTION OF REVISION	REV	DATE	DESCRIPTION OF REVISION
						3	3-22-05	REVISED VIBRATING FEEDER & DRAWDOWN HOPPER TAG NUMBERS
						2	2-25-05	ISSUED FOR AEP DESIGN FREEZE AND PER AEP/PARSONS COMMENTS
			5	10-28-05	REVISED PER AEP/PARSONS COMMENTS	1	12-28-04	FINAL ARRANGEMENT DRAWINGS ISSUED PER REQUIREMENT ID'S A002 & A030A
			4	5-20-05	REVISED PER AEP/PARSONS COMMENTS ADDED BREAKER INFO	0	12-3-04	FINAL PROFILE DRAWINGS ISSUED PER REQUIREMENT ID A003A

ROBERTS & SCHAEFER Company
ENGINEERS AND CONTRACTORS
CHICAGO — SALT LAKE CITY

FLOW DIAGRAM
LIMESTONE HANDLING SYSTEM
LIMESTONE & GYPSUM HANDLING SYSTEM
OHIO POWER COMPANY
AEP MITCHELL PLANT, UNITS 1 & 2, CRESAP, WEST VIRGINIA

MADE BY D.AMIN
CHECKED BY APD
DIRECTED BY RP
APPROVED BY
SCALE NONE
DATE 12-3-04
DRAWING No 0420-FS1
REV 5
CAD FILE NAME 0420-FS1

DWG. NO. 12-518703



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW

NOTES

(I) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D 5004E 5004

REFERENCE PROJECT PROCEDURE

FE-FL-EN-0001

DATE	NO.	DESCRIPTION	APPD.
06/21/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

s:/mt/1/flow_diagram/517802.dgn

AMERICAN ELECTRIC POWER

MITCHELL PLANT

CRESAP WEST VIRGINIA

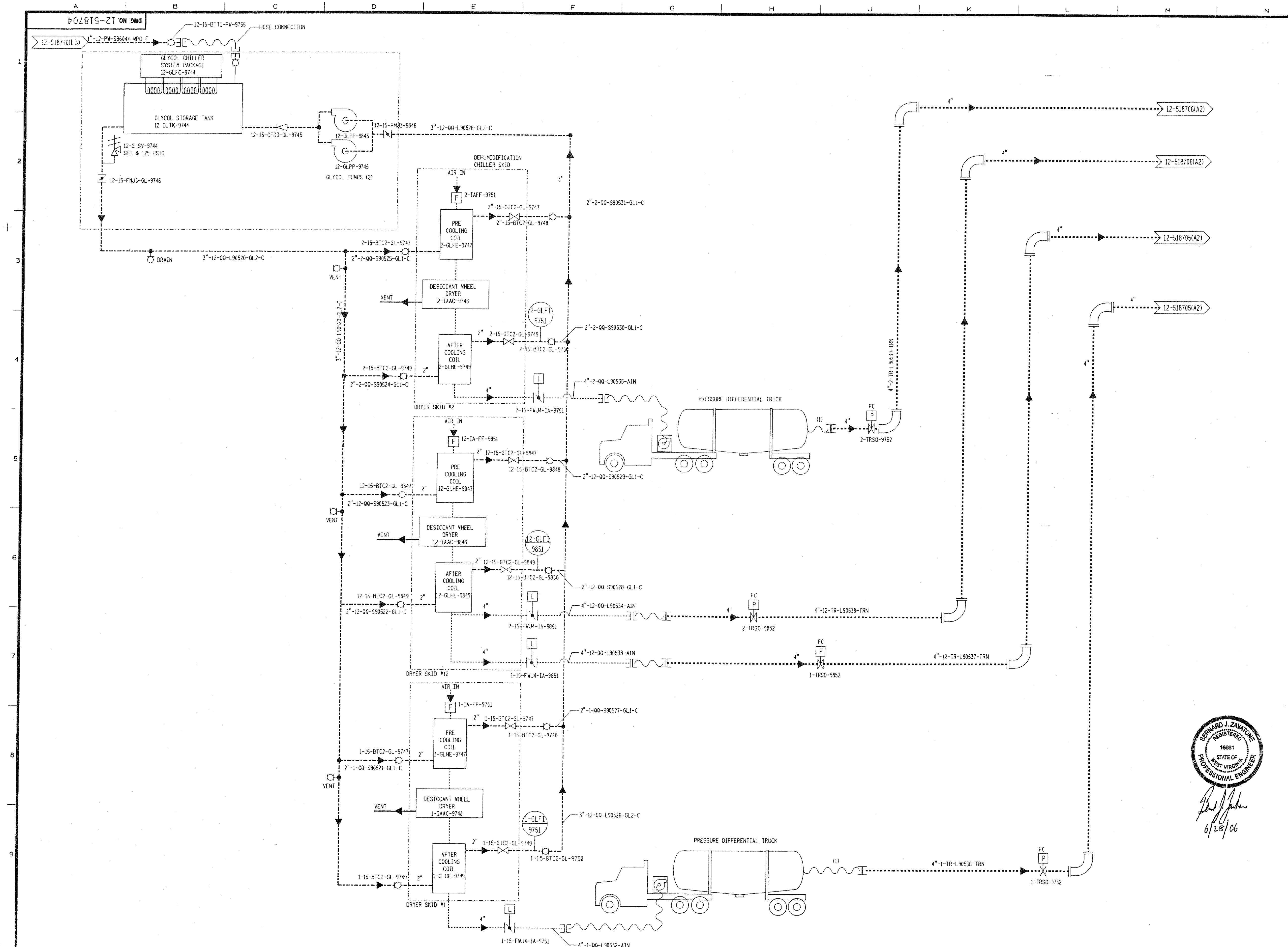
DSI SYSTEM COMPRESSED AIR & PD BLOWERS FLOW DIAGRAM

DWG. NO. 12-518703-0

SCALE: NONE
DR: RBS
CH:
DATE:
APPROVED BY

AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

SYSTEM DATE- 8/21/2006
SYSTEM TIME- 4:06:54 PM



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW

NOTES

(1) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D
5004E
5004

REFRENCE PROJECT PROCEDURE

PE-FL-EV-0001

DATE	NO.	DESCRIPTION	APPD.
06/21/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

s:/at/1/flow_diagram/518701.dgn

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

AMERICAN ELECTRIC POWER

MITCHELL PLANT

CRESAP WEST VIRGINIA

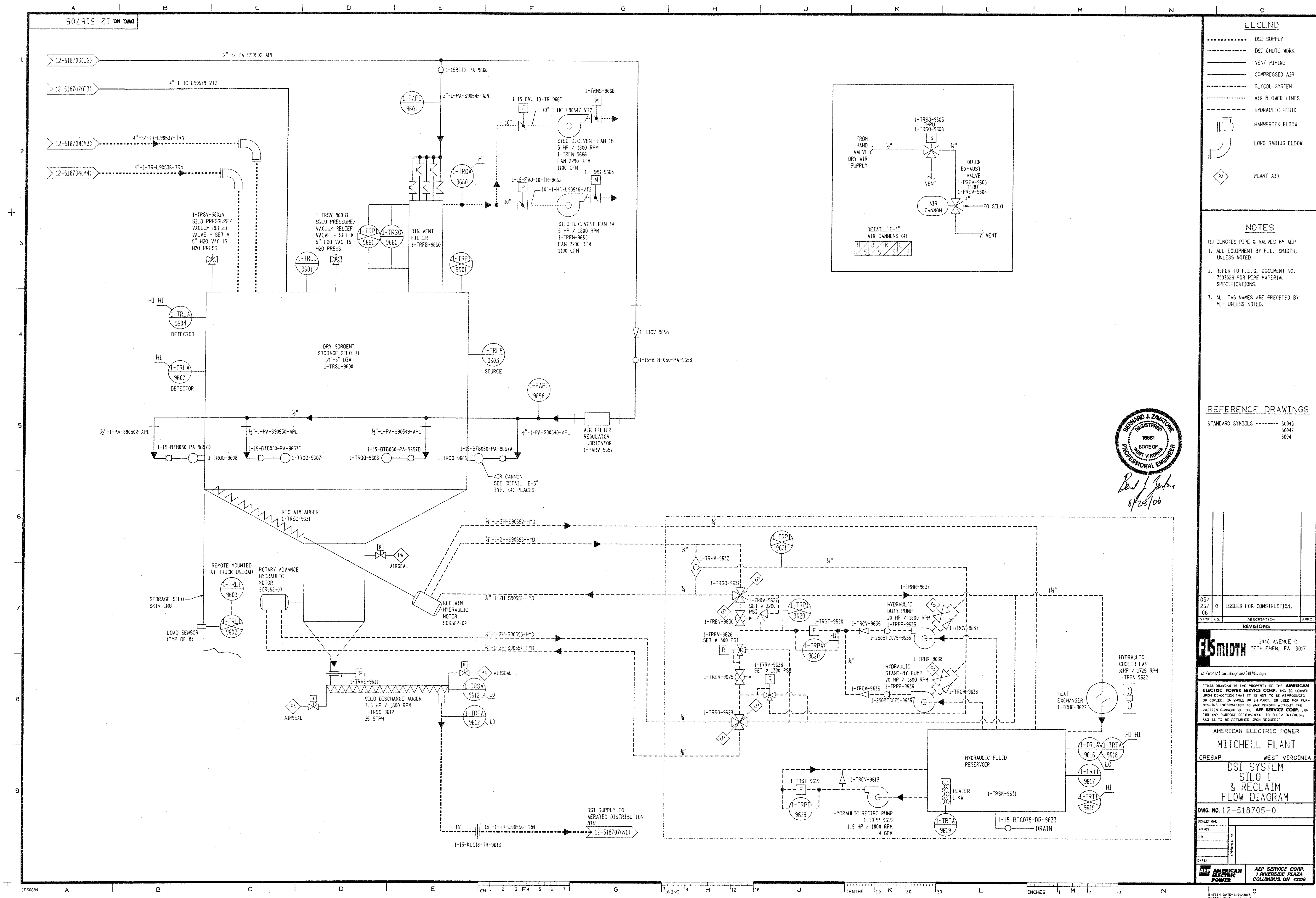
DSI SYSTEM CHILLER & DEHUMIDIFICATION FLOW DIAGRAM

DWG. NO. 12-518704-0

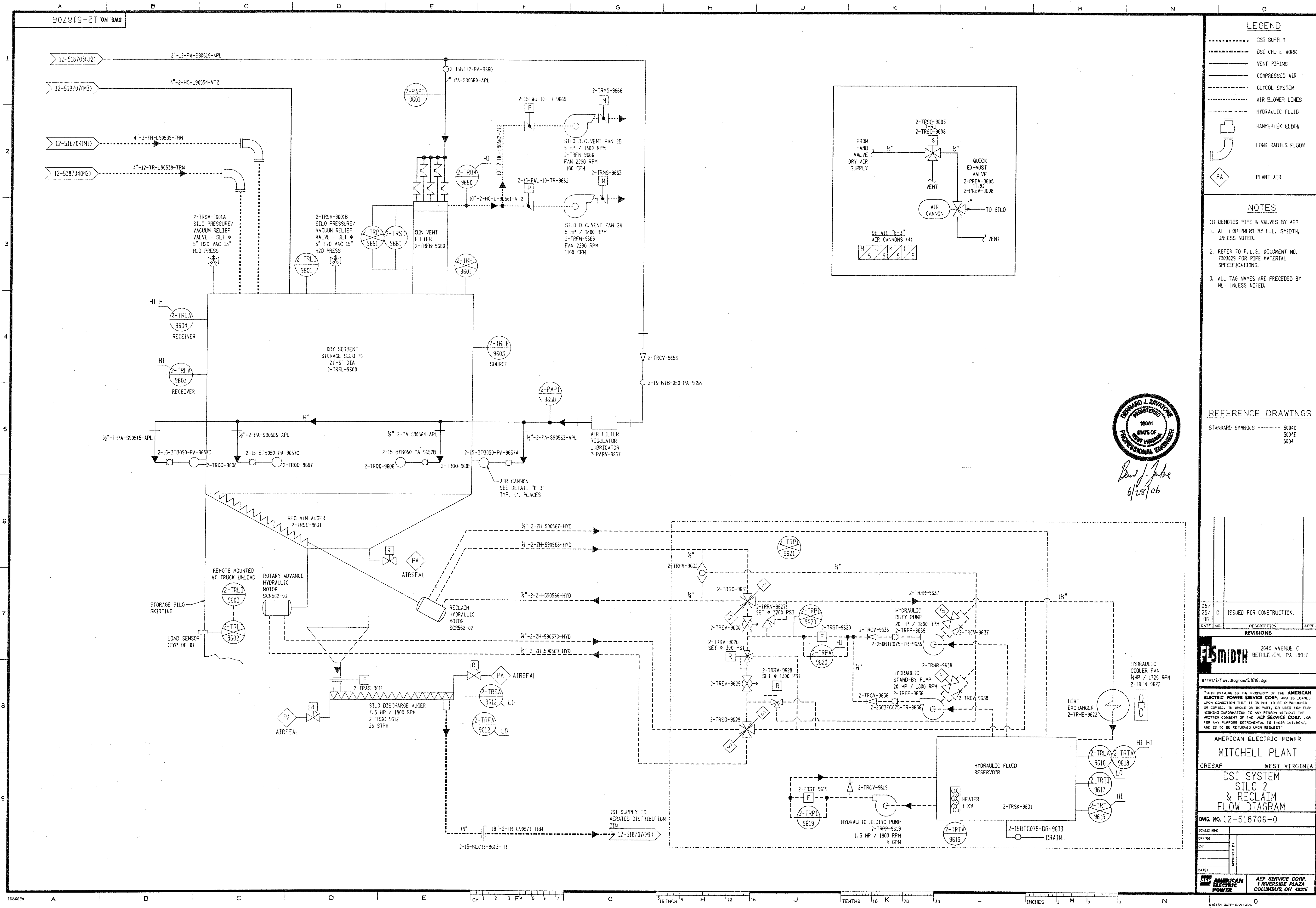
SCALE: NONE
DR: RDS
CH:
DATE:
APPROVED BY

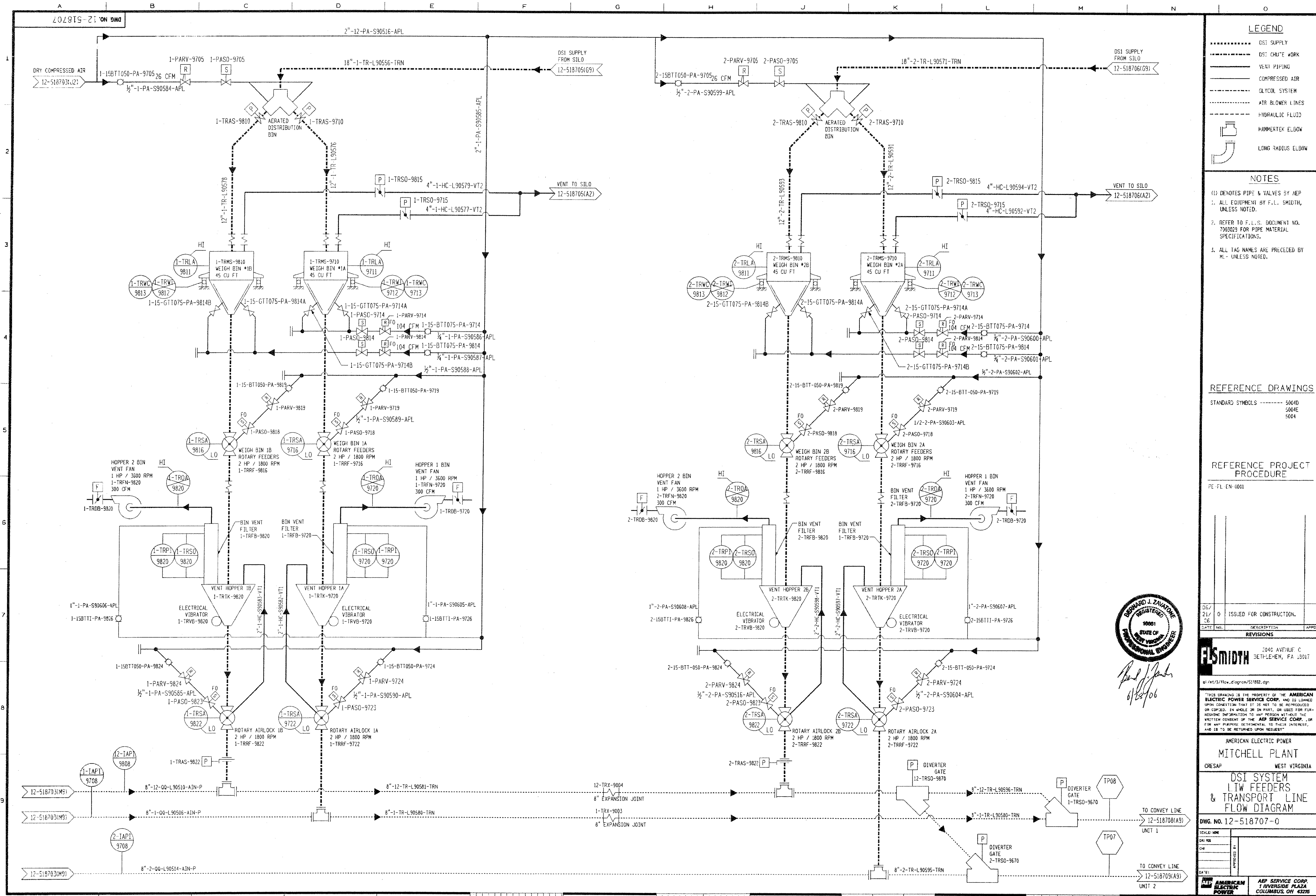
AEP AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

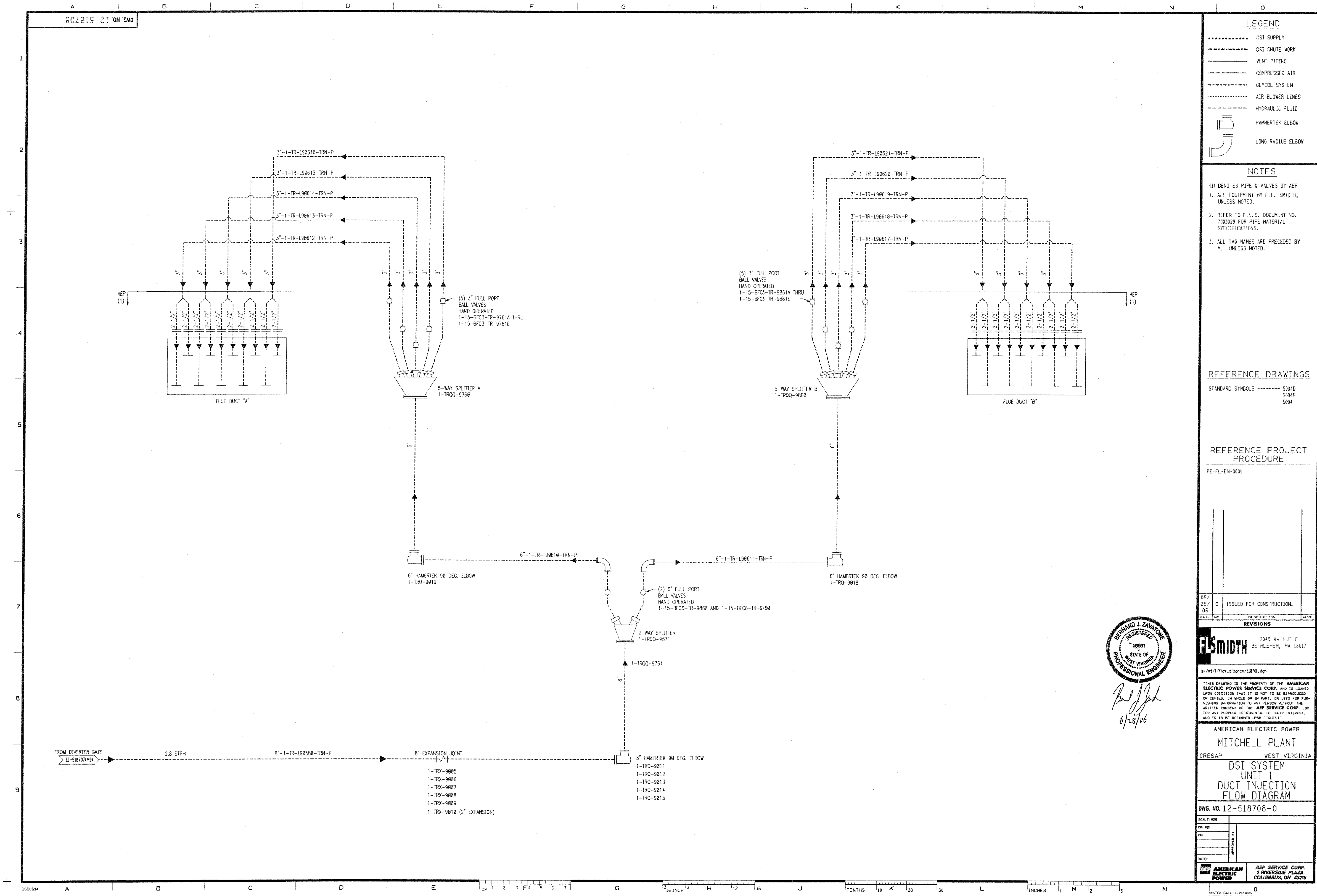
SYSTEM DATE- 6/21/2006
SYSTEM TIME- 4:06:57 PM



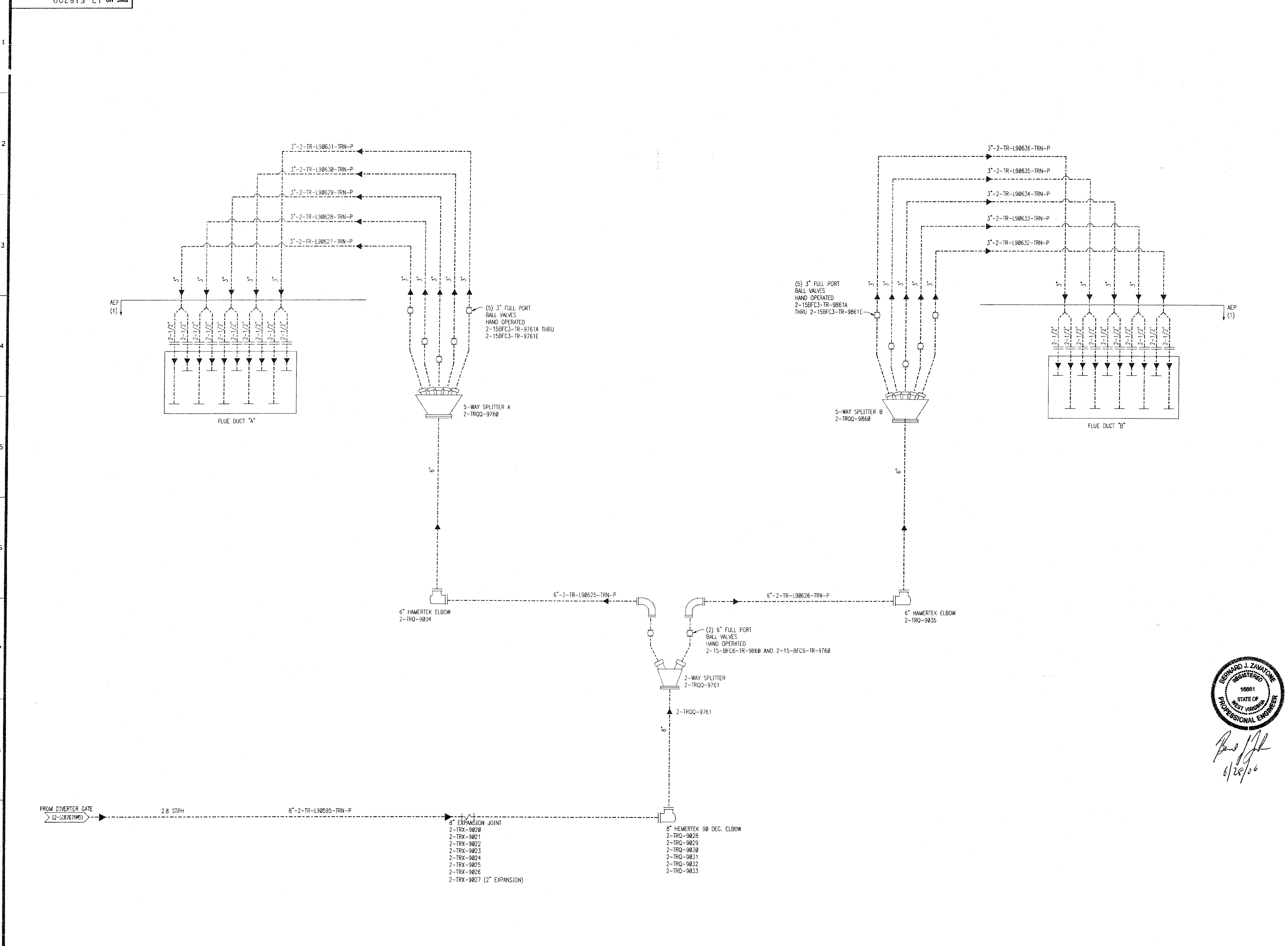
DWG. NO. 12-518705
LEGEND
DSI SUPPLY
DSI CHUTE WORK
VENT PIPING
COMPRESSED AIR
GLYCOL SYSTEM
AIR BLOWER LINES
HYDRAULIC FLUID
HAMMERTEK ELBOW
LONG RADIUS ELBOW
PLANT AIR
NOTES
( ) DENOTES PIPE & VALVES BY AEP
1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.
REFERENCE DRAWINGS
STANDARD SYMBOLS 5004D 5004E 5004
DETAIL "E-3" AIR CANNONS (4)
FROM HAND VALVE DRY AIR SUPPLY
QUICK EXHAUST VALVE 1-PREV-9605 THRU 1-PREV-9608
AIR CANNON
TO SILO
VENT
SILO D.C. VENT FAN 1B 5 HP / 1800 RPM 1-TRFN-9666 FAN 2290 RPM 1100 CFM
SILO D.C. VENT FAN 1A 5 HP / 1800 RPM 1-TRFN-9663 FAN 2290 RPM 1100 CFM
BIN VENT FILTER 1-TRFB-9660
1-TRSV-9601A SILO PRESSURE/ VACUUM RELIEF VALVE - SET @ 5" H2O VAC 15" H2O PRESS
1-TRSV-9601B SILO PRESSURE/ VACUUM RELIEF VALVE - SET @ 5" H2O VAC 15" H2O PRESS
DRY SORBENT STORAGE SILO #1 21'-6" DIA 1-TRSL-9600
DETECTOR
SOURCE
AIR FILTER REGULATOR LUBRICATOR 1-PARV-9657
AIR CANNON SEE DETAIL "E-3" TYP. (4) PLACES
RECLAIM AUGER 1-TRSC-9631
REMOTE MOUNTED AT TRUCK UNLOAD
ROTARY ADVANCE HYDRAULIC MOTOR SCR562-03
RECLAIM HYDRAULIC MOTOR SCR562-02
STORAGE SILO SKIRTING
LOAD SENSOR (TYP OF 8)
SILO DISCHARGE AUGER 7.5 HP / 1800 RPM 1-TRSC-9612 25 STPH
AIRSEAL
DSI SUPPLY TO AERATED DISTRIBUTION BIN 12-518707(N1)
HYDRAULIC DUTY PUMP 20 HP / 1800 RPM 1-TRPP-9635
HYDRAULIC STAND-BY PUMP 20 HP / 1800 RPM 1-TRPP-9636
HYDRAULIC COOLER FAN ½HP / 1725 RPM 1-TRFN-9622
HEAT EXCHANGER 1-TRHE-9622
HYDRAULIC FLUID RESERVOIR
HEATER 1 KW
1-TRSK-9631
HYDRAULIC RECIRC PUMP 1-TRPP-9619 1.5 HP / 1800 RPM 4 GPM
1-15-BTC075-DR-9633
DRAIN
05/25/06 0 ISSUED FOR CONSTRUCTION.
REVISIONS
FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017
AMERICAN ELECTRIC POWER
MITCHELL PLANT
CRESAP WEST VIRGINIA
DSI SYSTEM SILO 1 & RECLAIM FLOW DIAGRAM
DWG. NO. 12-518705-0
AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215
BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER
6/28/06


DWG. NO. 12-518706
LEGEND
DSI SUPPLY
DSI CHUTE WORK
VENT PIPING
COMPRESSED AIR
GLYCOL SYSTEM
AIR BLOWER LINES
HYDRAULIC FLUID
HAMMERTEK ELBOW
LONG RADIUS ELBOW
PLANT AIR
NOTES
(1) DENOTES PIPE & VALVES BY AEP
1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7303029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.
REFERENCE DRAWINGS
STANDARD SYMBOLS 5004D 5004E 5004
DRY SORBENT STORAGE SILO #2 21'-6" DIA 2-TRSL-9600
BIN VENT FILTER 2-TRFB-9660
SILO D.C. VENT FAN 2B 5 HP / 1800 RPM 2-TRFN-9666 FAN 2290 RPM 1100 CFM
SILO D.C. VENT FAN 2A 5 HP / 1800 RPM 2-TRFN-9663 FAN 2290 RPM 1100 CFM
2-TRSV-9601A SILO PRESSURE/ VACUUM RELIEF VALVE - SET @ 5" H2O VAC 15" H2O PRESS
2-TRSV-9601B SILO PRESSURE/ VACUUM RELIEF VALVE - SET @ 5" H2O VAC 15" H2O PRESS
RECLAIM AUGER 2-TRSC-9631
RECLAIM HYDRAULIC MOTOR SCR562-02
ROTARY ADVANCE HYDRAULIC MOTOR SCR562-03
REMOTE MOUNTED AT TRUCK UNLOAD
STORAGE SILO SKIRTING
LOAD SENSOR (TYP OF 8)
AIR FILTER REGULATOR LUBRICATOR 2-PARV-9657
AIR CANNON SEE DETAIL "E-3" TYP. (4) PLACES
SILO DISCHARGE AUGER 7.5 HP / 1800 RPM 2-TRSC-9612 25 STPH
AIRSEAL
DSI SUPPLY TO AERATED DISTRIBUTION BIN 12-518707(M1)
DETAIL "E-3" AIR CANNONS (4)
FROM HAND VALVE DRY AIR SUPPLY
QUICK EXHAUST VALVE 2-PREV-9605 THRU 2-PREV-9608
AIR CANNON
TO SILO
VENT
HYDRAULIC DUTY PUMP 20 HP / 1800 RPM 2-TRPP-9635
HYDRAULIC STAND-BY PUMP 20 HP / 1800 RPM 2-TRPP-9636
HYDRAULIC COOLER FAN 1/2HP / 1725 RPM 2-TRFN-9622
HEAT EXCHANGER 2-TRHE-9622
HYDRAULIC FLUID RESERVOIR
HEATER 1 KW
2-TRSK-9631
HYDRAULIC RECIRC PUMP 2-TRPP-9619 1.5 HP / 1800 RPM 4 GPM
2-15BTC075-DR-9633
DRAIN
05/25/06 0 ISSUED FOR CONSTRUCTION.
REVISIONS
FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017
AMERICAN ELECTRIC POWER
MITCHELL PLANT
CRESAP WEST VIRGINIA
DSI SYSTEM SILO 2 & RECLAIM FLOW DIAGRAM
DWG. NO. 12-518706-0
AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215
BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER
6/28/06


DWG NO. 12-518707
LEGEND
DSI SUPPLY
DSI CHUTE WORK
VENT PIPING
COMPRESSED AIR
GLYCOL SYSTEM
AIR BLOWER LINES
HYDRAULIC FLUID
HAMMERTEK ELBOW
LONG RADIUS ELBOW
NOTES
(1) DENOTES PIPE & VALVES BY AEP
1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.
REFERENCE DRAWINGS
STANDARD SYMBOLS 5004D 5004E 5004
REFERENCE PROJECT PROCEDURE
PE-FL-EN-0001
06/21/06 0 ISSUED FOR CONSTRUCTION.
DATE NO. DESCRIPTION APPD.
REVISIONS
FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017
AMERICAN ELECTRIC POWER
MITCHELL PLANT
CRESAP WEST VIRGINIA
DSI SYSTEM LIW FEEDERS & TRANSPORT LINE FLOW DIAGRAM
DWG. NO. 12-518707-0
AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215
DRY COMPRESSED AIR 12-518703(J2)
DSI SUPPLY FROM SILO 12-518705(G9)
DSI SUPPLY FROM SILO 12-518706(G9)
VENT TO SILO 12-518705(A2)
VENT TO SILO 12-518706(A2)
AERATED DISTRIBUTION BIN
1-TRMS-9810 WEIGH BIN #1B 45 CU FT
1-TRMS-9710 WEIGH BIN #1A 45 CU FT
2-TRMS-9810 WEIGH BIN #2B 45 CU FT
2-TRMS-9710 WEIGH BIN #2A 45 CU FT
WEIGH BIN 1B ROTARY FEEDERS 2 HP / 1800 RPM 1-TRRF-9816
WEIGH BIN 1A ROTARY FEEDERS 2 HP / 1800 RPM 1-TRRF-9716
WEIGH BIN 2B ROTARY FEEDERS 2 HP / 1800 RPM 2-TRRF-9816
WEIGH BIN 2A ROTARY FEEDERS 2 HP / 1800 RPM 2-TRRF-9716
HOPPER 2 BIN VENT FAN 1 HP / 3600 RPM 1-TRFN-9820 300 CFM
HOPPER 1 BIN VENT FAN 1 HP / 3600 RPM 1-TRFN-9720 300 CFM
BIN VENT FILTER 1-TRFB-9820
BIN VENT FILTER 1-TRFB-9720
VENT HOPPER 1B 1-TRTK-9820
VENT HOPPER 1A 1-TRTK-9720
VENT HOPPER 2B 2-TRTK-9820
VENT HOPPER 2A 2-TRTK-9720
ELECTRICAL VIBRATOR 1-TRVB-9820
ELECTRICAL VIBRATOR 1-TRVB-9720
ROTARY AIRLOCK 1B 2 HP / 1800 RPM 1-TRRF-9822
ROTARY AIRLOCK 1A 2 HP / 1800 RPM 1-TRRF-9722
ROTARY AIRLOCK 2B 2 HP / 1800 RPM 2-TRRF-9822
ROTARY AIRLOCK 2A 2 HP / 1800 RPM 2-TRRF-9722
8" EXPANSION JOINT
DIVERTER GATE 12-TRSO-9870
DIVERTER GATE 1-TRSO-9670
DIVERTER GATE 2-TRSO-9670
TO CONVEY LINE 12-518708(A9) UNIT 1
TO CONVEY LINE 12-518709(A9) UNIT 2
12-518703(M9)


DWG. NO. 12-518708
LEGEND
DSI SUPPLY
DSI CHUTE WORK
VENT PIPING
COMPRESSED AIR
GLYCOL SYSTEM
AIR BLOWER LINES
HYDRAULIC FLUID
HAMMERTEK ELBOW
LONG RADIUS ELBOW
NOTES
(1) DENOTES PIPE & VALVES BY AEP
1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7002029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML UNLESS NOTED.
REFERENCE DRAWINGS
STANDARD SYMBOLS 5004D 5004E 5004
REFERENCE PROJECT PROCEDURE
PE-FL-EN-0001
3"-1-TR-L90616-TRN-P
3"-1-TR-L90615-TRN-P
3"-1-TR-L90614-TRN-P
3"-1-TR-L90613-TRN-P
3"-1-TR-L90612-TRN-P
3"-1-TR-L90621-TRN-P
3"-1-TR-L90620-TRN-P
3"-1-TR-L90619-TRN-P
3"-1-TR-L90618-TRN-P
3"-1-TR-L90617-TRN-P
AEP (1)
(5) 3" FULL PORT BALL VALVES HAND OPERATED 1-15-BFC3-TR-9761A THRU 1-15-BFC3-TR-9761E
(5) 3" FULL PORT BALL VALVES HAND OPERATED 1-15-BFC3-TR-9861A THRU 1-15-BFC3-TR-9861E
FLUE DUCT "A"
FLUE DUCT "B"
5-WAY SPLITTER A 1-TRQQ-9760
5-WAY SPLITTER B 1-TRQQ-9860
6"-1-TR-L90610-TRN-P
6"-1-TR-L90611-TRN-P
6" HAMERTEK 90 DEG. ELBOW 1-TRQ-9019
6" HAMERTEK 90 DEG. ELBOW 1-TRQ-9018
(2) 6" FULL PORT BALL VALVES HAND OPERATED 1-15-BFC6-TR-9860 AND 1-15-BFC6-TR-9760
2-WAY SPLITTER 1-TRQQ-9671
1-TRQQ-9761
FROM DIVERTER GATE 12-518707(M0)
2.8 STPH
8"-1-TR-L90580-TRN-P
8" EXPANSION JOINT
1-TRX-9005
1-TRX-9006
1-TRX-9007
1-TRX-9008
1-TRX-9009
1-TRX-9010 (2" EXPANSION)
8" HAMERTEK 90 DEG. ELBOW
1-TRQ-9011
1-TRQ-9012
1-TRQ-9013
1-TRQ-9014
1-TRQ-9015
05/25/06 0 ISSUED FOR CONSTRUCTION.
DATE NO. DESCRIPTION APPR.
REVISIONS
FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017
BERNARD J. ZAVATONE REGISTERED 18661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER
6/28/06
"THIS DRAWING IS THE PROPERTY OF THE AMERICAN ELECTRIC POWER SERVICE CORP. AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT THE WRITTEN CONSENT OF THE AEP SERVICE CORP., OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST, AND IS TO BE RETURNED UPON REQUEST."
AMERICAN ELECTRIC POWER
MITCHELL PLANT
CRESAP WEST VIRGINIA
DSI SYSTEM UNIT 1 DUCT INJECTION FLOW DIAGRAM
DWG. NO. 12-518706-0
AMERICAN ELECTRIC POWER
AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

DWG. NO. 12-518709



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW

NOTES

(1) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS --------- 5004D
5004E
5004

REFERENCE PROJECT PROCEDURE

PE-FL-EN-0001

DATE	NO.	DESCRIPTION	APPD.
05/25/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

BERNARD J. ZAVATONE REGISTERED 16861 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

s:/mt/1/flow_diagram/518701.dgn

AMERICAN ELECTRIC POWER

MITCHELL PLANT

CRESAP WEST VIRGINIA

DSI SYSTEM UNIT 2 DUCT INSERTION FLOW DIAGRAM

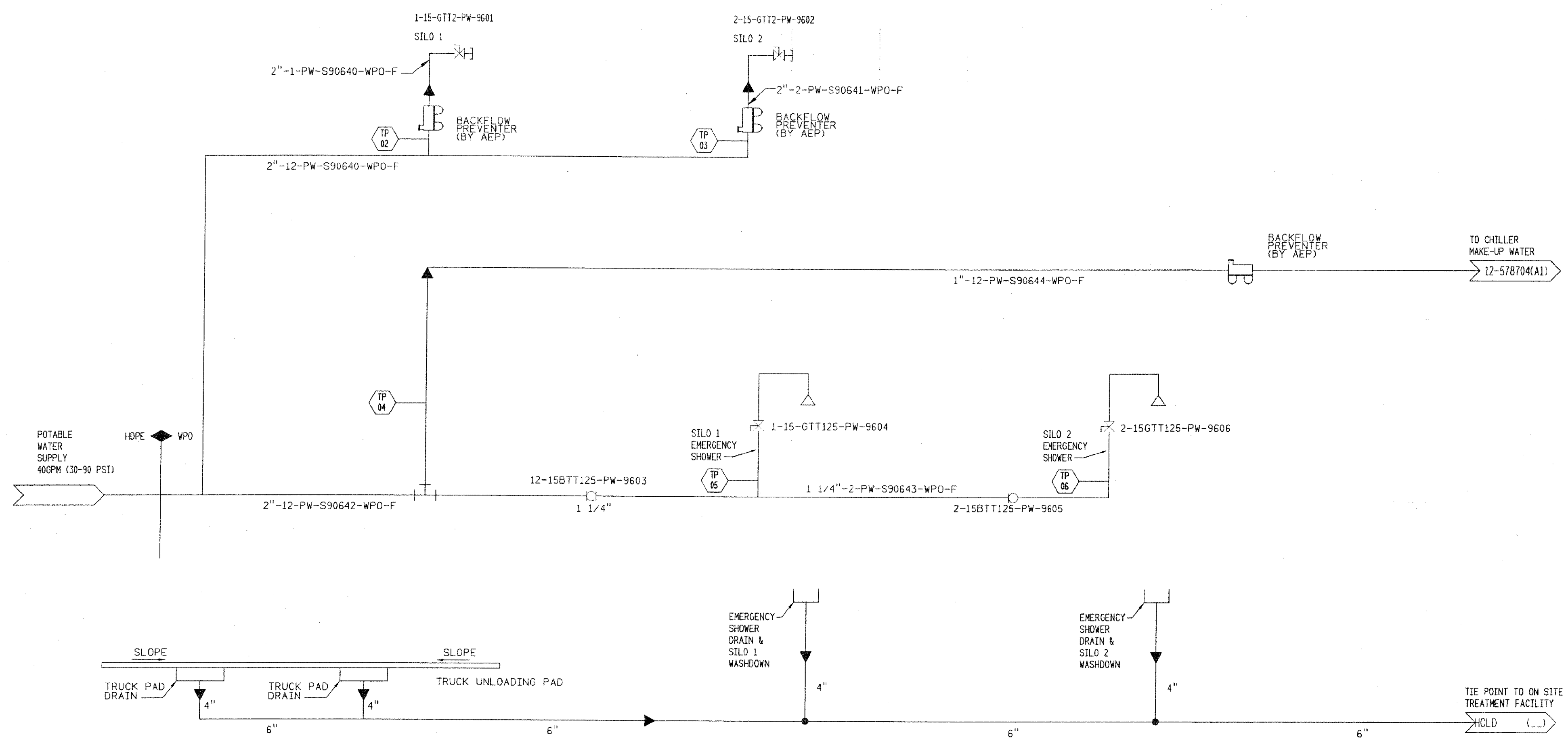
DWG. NO. 12-518709-0

SCALE: NONE
DR: RDB
CH:
DATE:
APPROVED BY

AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

SYSTEM DATE-6/21/2006
SYSTEM TIME-4:07:13 PM

DWG. NO.12-518710



(1) DENOTES PIPE & VALVES BY AEP

NOTES

FOR GENERAL NOTES SEE DRAWING 1-518701

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003023 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D 5004E 5004

REFERENCE PROJECT PROCEDURE

DATE	NO.	DESCRIPTION	APPD
	0	ISSUED FOR CONSTRUCTION	

REVISIONS

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

APPALACHIAN POWER COMPANY

MITCHELL PLANT

CRESAP WEST VIRGINIA

DSI SYSTEM
SERVICE WATER
& POTABLE WATER
FLOW DIAGRAM

DWG. NO.12-518710-0

SCALE: NONE — MECHANICAL ENGINEERING DIVISION

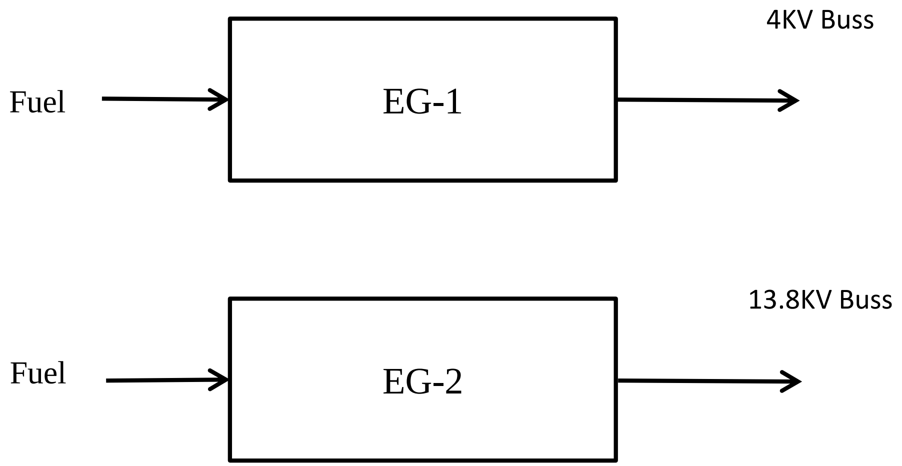
RIVER CONSULTING — New Orleans - Columbus - Pittsburgh - Salt Lake City - Houston

FLSMIDTH

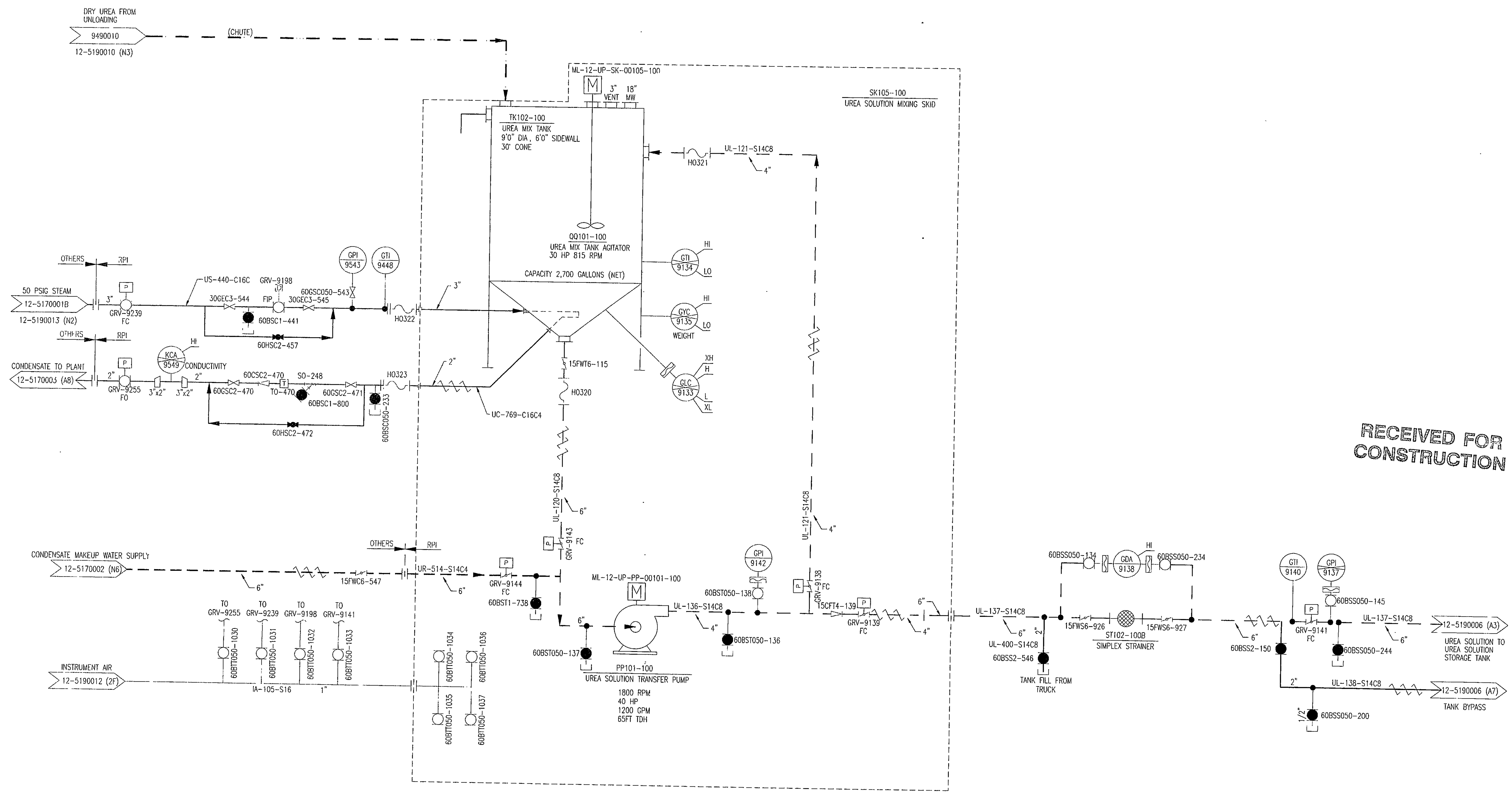
AEP AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

Flow Diagram

Coping Power Diesel Driven Emergency Generators



DWG. NO.100273-9490020



RECEIVED FOR CONSTRUCTION

NOTES:

1. DELETED
2. ALL TAG #'S PREFACED WITH ML12 UNLESS OTHERWISE SPECIFIED

LEGEND

- DRY UREA
- UREA SOLUTION
- MAKE-UP WATER
- AUX PIPING

ALTERATION	NO	BY	CHK	DATE	APP'D	DATE
CORRECT ARROW REFS, DELETED LINE TO SUMP, ADDED DRAIN VALVE, RELOCATED DRAIN VALVE, ADDED TRAP STRAINER TAG & DRAIN LINE TAG	05	LKT	[illegible]	5/5/06	[illegible]	5/11/06
RE-ISSUE FOR CONSTRUCTION	04	JWL	RB	11/17/05	CAE	11/18/05
ISSUE FOR CONSTRUCTION	03	JWL	BH	05/20/05	CAE	05/20/05
RELEASED FOR APPROVAL	02	JWL	TN	04/30/05	CAE	05/01/05
RELEASED FOR CERTIFICATION	01	JWL	TN	04/12/05	BH	04/12/05

"N" MATERIAL NOT FURNISHED BY
"F" MATERIAL FURNISHED BY
RILEY POWER INC.

THIS DRAWING IS NOT APPROVED FOR CONSTRUCTION UNLESS IT CONTAINS DATE AND SIGNATURE OF APPROVAL AND THE COMPANY RESERVES THE RIGHT TO CORRECT ANY ERRORS OR OMISSIONS PRIOR TO ACTUAL START OF WORK

CLAYTON ERICKSON 05/20/05
RELEASED & APPROVED DATE

DRAWN JWL DATE 04/28/05
CHECKED RH DATE 03/17/05
APP'D RJ DATE 03/17/05

DO NOT SCALE
USE DIMENSIONS ONLY

SCALE NTS IN = 1 FT.

ES	W	F	ER

FUNCTIONAL REVIEW / APPROVAL

REVIEWED & APP'D / DATE	REVIEWED & APP'D / DATE
RB 11/17/05	
RHF 11/18/05	
C.ERICKSON 11/18/05	
B BASILE 11/18/05	

	NO	DESCRIPTION	APPD
	2	CORRECT ARROW REFS, DELETED LINE TO SUMP, ADDED DRAIN VALVE, RELOCATED DRAIN VALVE, ADDED TRAP STRAINER TAG & DRAIN LINE TAG	
	1	RE-ISSUE FOR CONSTRUCTION	
	0	ISSUE FOR CONSTRUCTION	

REVISIONS

03389 - 12-5190011 - - - 2
AEPM-12-DV-094502-
12-5190011-R2(6)

OHIO POWER COMPANY

MITCHELL PLANT

CRESAP WEST VIRGINIA

FLOW DIAGRAM UREA MIX TANK

U2A SYSTEM

RILEY POWER INC.

PIPING AND INSTRUMENTATION DIAGRAM
UREA MIX TANK
U2A SYSTEM
MITCHELL PLANT - UNITS #1 & 2
AMERICAN ELECTRIC POWER
CRESAP, WEST VIRGINIA

DWG. NO 100273-9490020-05

DWG. NO. 12-5190011 -2

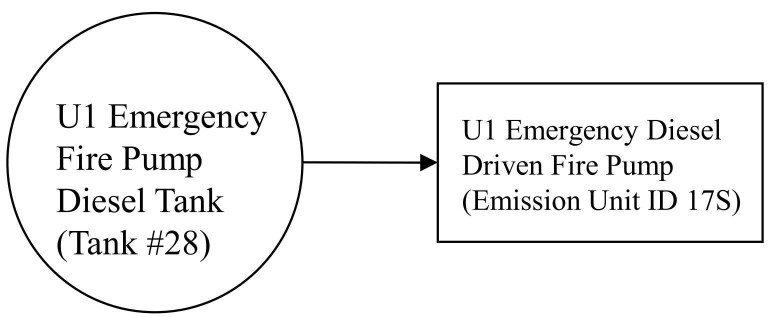
SCALE: none
DR.
CH
DES SUPV
ENGR.
DATE.
APPROVED BY

DOCUMENT PREPARED BY RILEY POWER INC.

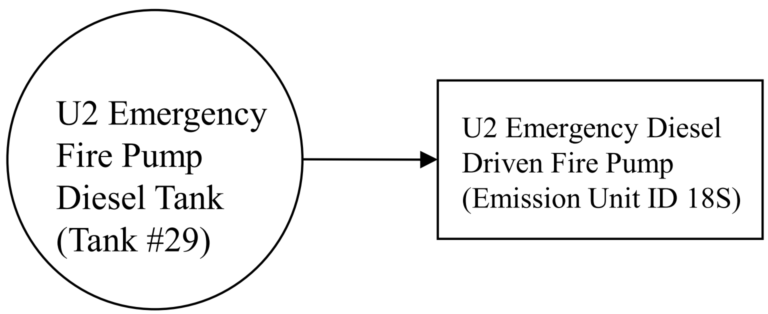
AMERICAN ELECTRIC

AEP SERVICE CORP.
1 RIVERSIDE PLAZA

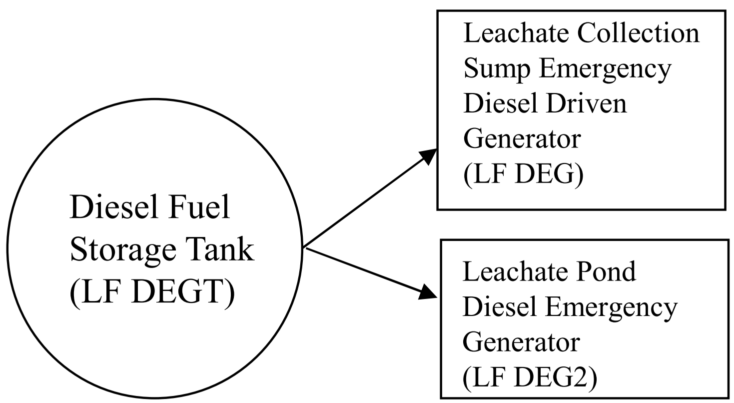
Attachment C:
Mitchell Plant Unit 1 Emergency Diesel Driven Fire Pump



Attachment C:
Mitchell Plant Unit 2 Emergency Diesel Driven Fire Pump



Attachment C:
Mitchell Plant Diesel Driven Emergency Generators Located at Landfill Leachate Collection Sump and Leachate Pond



Attachment D

Title V Equipment Table

ATTACHMENT D - Title V Equipment Table (includes all emission units at the facility except those designated as insignificant activities in Section 4, Item 24 of the General Forms)					
Emission Point ID[1]	Control Device[1]	Emission Unit ID[1]	Emission Unit Description	Design Capacity	Year Installed/ Modified
Boiler & Associated Equipment					
Unit 1	High efficiency	1E	Boiler: Foster Wheeler, Model # 2-85-303	7020 mmBtu/hr	1971
Unit 2	High efficiency	2E	Boiler: Foster Wheeler, Model # 2-85-304	7020 mmBtu/hr	1971
Aux 1	N/A	Aux ML1	Boiler: Foster Wheeler, Model # SD- 25	663 mmBtu/hr	1970, Reconstructed in 2012
17E	None	17S	Unit 1 Emergency Diesel Driven Fire Pump	249 HP	~1971, Replaced in 2023
18E	None	18S	Unit 2 Emergency Diesel Driven Fire Pump	249 HP	~1971, Replaced in 2024
EG-1	None	EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	3,717-bhp@ 1,800rpm	2014
EG-2	None	EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	3,004-bhp@ 1,800rpm	2014
LF DEG	None	LF DEG	Landfill Leachate Collection Sump Emergency Diesel Driven Generator, 2019 Cummins C300DQDAC model	464 bhp 300kW	2020
LF DEG2	None	LF DEG2	Landfill Leachate Pond Diesel Emergency Generator, 2023 Cummins QSG12 model	513 bhp 400kW	2023
LF DEGT	None	LF DEGT	Diesel Fuel Storage Tank for LF DEG	600 gallons	2020
LF DEGT2	None	LF DEGT2	Diesel Fuel Storage Tank for LF DEG2	600 gallons	2023
EGT01	None	EGT01	Diesel Fuel Storage Tank for EG-1	4,800 gallons	2014
EGT02	None	EGT02	Diesel Fuel Storage Tank for EG-2	4,800 gallons	2014
Coal Handling					
BU	WS, PE, MC	BU	Barge Unloader (unload barge onto Conveyor R1	4,000 TPH	1971
Station R1	FE, MC	Sta-R1	Conveyor R1 and drop points to Conveyor R2	3,000 TPH	1971
C-R2	WS, PE, MC	C-R2	Conveyor R2 (transfer to Station R2)	3,000 TPH	1971
RCU	WS, MC	RCU	Rail Car Unloader (unload rail cars to feeders R6-1, R6-2 and R6-3)	3,000 TPH	April, 1974
R6-1, R6-2, R6-3	PE, MC	R6-1, R6-2, R6-3	Feeders R6-1, R6-2, R6-3 (transfer points to Conveyor R7)	1,400 TPH	April 1974
C-R7	WS, PE, MC	C-R7	Conveyor R7 (transfer to Station R2)	3,000 TPH	April 1974
Station R2	FE, MC	Sta-R2	Drop point to coal crusher or conveyor R3	N/A	April 1974
CR-R2	FE, MC	CR-R2	Coal Crusher	2,500 TPH	1971

C-R3	PE, MC	C-R3	Conveyor R3 (transfer to Station R3)	3,000 TPH	1971
Station R3	FE, MC	Sta-R3	Drop point to conveyor R4 or R1 1	N/A	1971
C-R1 1	PE, MC	C-R1 1	Conveyor R1 1 (transfer to radial portable Conveyor R12)	3,000 TPH	1971
C-R12	MC	C-R12	Radial Portable Conveyor R12 (transfer to temporary storage pile)	3,000 TPH	1971
C-R4	PE, MC	C-R4	Conveyor R4 (transfer to Station R4)	3,000 TPH	1971
Station R4	FE, MC	Sta-R4	Drop point to Sample System and Conveyor R5; and/or Conveyor R8	N/A	1971
C-R8	PE, MC	C-R8	Conveyor R8 (transfer to Radial Stacker Conveyor R9)	3,000 TPH	April 1974
C-R9	MC	C-R9	Radial Stacker Conveyor R9 (transfer to North Yard Storage Pile – Station R7)	3,000 TPH	April 1974
Station R7	FE, MC	Sta-R7	Drop point from North Yard Storage Pile through Crusher R7-1 to Feeder Conveyor BFR7-1	N/A	April 1974
CR-R7-1	FE, MC	CR-R7-1	Coal Crusher	1,000 TPH	April 1974
BFR7-1	FE, MC	BFR7-1	Feeder BFR7-1 (transfer to Conveyor R10)	1,100 TPH	April 1974
C-R1 0	PE, MC	C-R10	Conveyor R10 (transfer to truck load out and Station R4)	1,100 TPH	April 1974
C-R5	PE, MC	C-R5	Conveyor R5 (transfer to Drive Tower S1)	3,000 TPH	1971
Drive Tower S1	FE, MC	Drive Tower S1	Drop point to Conveyor R6	N/A	1971
C-R6	PE, MC	C-R6	Conveyor R6 (transfer to Station 2)	3,000 TPH	1971
Station 2	FE, MC	Sta-2	Drop point to Radial Stacker Conveyor 2	N/A	1969
RS-2	WS, MC	RS-2	Radial Stacker 2 (transfer to surge pile)	4,000 TPH	1969
Station 1A	FE, MC	Sta-1A	Drop point from frozen coal storage area 4 through crusher CR-1A to Conveyor 1A	N/A	1969
CR-1A	FE, MC	CR-1A	Coal Crusher	1,000 TPH	1969
C-1A	PE, MC	C-1A	Conveyor 1A (transfer to Station 1B)	1,100 TPH	1969
Station 1B	FE, MC	Sta-1B	Drop point to Conveyor 1	N/A	1969
C-1	PE, MC	C-1	Conveyor 1 (transfer to Station 2)	2,600 TPH	1969
CSA-1	MC	CSA-1	Coal Storage Area #1 (Surge Pile)	Approx 40 Acres	1969
CSA-2	MC	CSA-2	Coal Storage Area #2 (North Yard Storage Pile)	Approx 40 Acres	April 1974
CSA-3	MC	CSA-3	Coal Storage Area #3 (Temporary Storage Pile at R3)	Approx 6 Acres	
CSA-4	MC	CSA-4	Coal Storage Area #4 (conveyor from 1B)	Included in CSA-1	1969
SGM1 through SGM16	FE, MC	SGM1 through	Reclaim Hoppers/Vibratory Feeders (Reclaim Area #1 surge pile) transfers to Conveyors 3A, 3B and 3C	300 TPH each	1969
C-3A	FE, MC	C-3A	Conveyor 3A (transfer to Station 3B)	1,100 TPH	1969
Station 3B	FE, MC	Sta-3B	Drop point to Conveyor 3B	N/A	1969
C-3B	FE, MC	C-3B	Conveyor 3B (transfer to Station 3)	1,100 TPH	1969
C-3C	FE, MC	C-3C	Conveyor 3C (transfer to Station 3)	1,100 TPH	1969
Station 3	FE, MC	Sta-3	Drop point to Conveyors 4E and/or 4W	N/A	1969

C-4E/C-4W	PE, MC	C-4E/C-4W	Conveyors 4E and 4W (transfer to Station 4)	1,100 TPH each	1969
Station 4	FE, MC	Sta-4	Drop point to Sample System, Conveyor 7E and/or 7W, and Conveyor 5 or Emergency Conveyors E25 through E2 1	N/A	1969
C-7E/C-7W	PE, MC	C-7E/C-7W	Conveyors 7E and 7W (transfer to Station 5	1,100 TPH each	1969
C-5	FE, MC	C5	Conveyor 5 (transfer to Unit 2 coal silos 3, 4 or 5 and to Conveyor 6)	1,100 TPH	1969
C-6	FE, MC	C-6	Conveyor 6 (transfer to Unit 2 coal silos 1 or 2)	1,100 TPH	1969
C-E25 through C- E21	MC	C-E25 through C-E21	Emergency conveyors E25 through E21 (used in an emergency to transfer coal into Unit 2 coal silos)	500 TPH each	1969
Station 5	FE, MC	Sta-5	Drop point to Conveyor 8 or Emergency Conveyors E1 1 through E15	N/A	1969
C-8	FE, MC	C-8	Conveyor 8 (transfer to Unit 1 coal silos 3, 4, or 5 and to Conveyor 9)	1,100 TPH	1969
C-9	FE, MC	C-9	Conveyor 9 (transfer to Unit 1 coal silos 1 or 2)	1,100 TPH	1969
C-E1 1 through C- E15	MC	C-E1 1 through C-E15	Emergency conveyors E1 1 through E15 (used in an emergency to transfer coal into Unit 1 coal silos)	500 TPH	1969
Fly Ash Material Handling					
Haul Roads	Water Truck	Haul Roads	Fly Ash Material Haul Roads and Landfill	N/A	N/A
EP-1	Filter/Separator	ME-1A	Unit 1 Mechanical Exhauster 1A	N/A	2012
EP-2	Filter/Separator	ME-1B	Unit 1 Mechanical Exhauster 1B	N/A	2012
EP-3	Filter/Separator	ME-1C (spare)	Unit 1 Mechanical Exhauster 1C	N/A	2012
EP-4	Filter/Separator	ME-2A	Unit 2 Mechanical Exhauster 2A	N/A	2012
EP-5	Filter/Separator	ME-2B	Unit 2 Mechanical Exhauster 2B	N/A	2012
EP-6	Filter/Separator	ME-2C (spare)	Unit 2 Mechanical Exhauster 2C	N/A	2012
EP-7	BVF-A	FAS-A	Fly Ash Silo A	2,160 tons	2012
EP-8	BVF-B	FAS-B	Fly Ash Silo B	2,160 tons	2012
EP-9	BVF-C	FAS-C	Fly Ash Silo C	2,160 tons	Future
F-1	MC	WFA-AA	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	360 tph	2012
F-2	MC	WFA-BA	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	360 tph	2012
F-3	MC	WFA-CA	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	360 tph	Future
F-4	MC	WFA-AB (spare)	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	360 tph	2012
F-5	MC	WFA-BB (spare)	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	360 tph	2012
F-6	MC	WFA-CB (spare)	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	360 tph	Future
EP-10, F-7	TC	TC-A	Transfer dry fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	300 tph	2012
EP-11, F-8	TC	TC-B	Transfer dry fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	300 tph	2012
EP-12, F-9	TC	TC-C	Transfer dry fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	300 tph	Future

~~LPG~~	~~None~~	~~LPG~~	~~Generac SG080, Lean Burn Four Stroke, Liquid Propane Gas-fired emergency generator Certificate No. DGNXB08.92NL-011~~	~~126 bhp~~	~~2013~~ **(Removed)**
~~LPT~~	~~None~~	~~LPT~~	~~Liquid Propane Tank for LPG~~	~~500 gallons~~	~~2013~~ **(Removed)**
1S – Limestone Material Handling					
BUN-1 (Fugitive)	None	BUN-1	Limestone Unloading Crane	1,000 TPH	2006
RH-1 (Fugitive)	WS, PE	RH-1	Limestone Unloading Hopper	60 Tons	2006
VF-1 (Fugitive)	FE	VF-1	Limestone Unloading Feeder	750 TPH	2006
BC-1 (Fugitive)	PE	BC-1	Limestone Dock/Connecting Conveyor	750 TPH	2006
TH-1 (Fugitive)	FE	TH-1	Limestone Transfer House #1	750 TPH	2006
BC-2 (Fugitive)	PE	BC-2	Limestone Storage Pile Stacking Conveyor	750 TPH	2006
LSSP (Fugitive)	None	LSSP	Limestone Active/Long-Term Stockpile	155,000 Tons	2006/2011
2S - Gypsum Material Handling					
BC-8 (Fugitive)	PE	BC-8	Vacuum Collecting Conveyor	200 TPH	2007
TH-3 (Fugitive)	FE	TH-3	Gypsum Transfer House #3	200 TPH	2007
BC-9 (Fugitive)	PE	BC-9	Connecting Conveyor	200 TPH	2007
TH-4 (Fugitive)	FE	TH-4	Gypsum Transfer House #4	200 TPH	2007
BC-10 (Fugitive)	PE	BC-10	Connecting Conveyor	200 TPH	2007
TH-5 (Fugitive)	FE	TH-5	Gypsum Transfer House #5	200 TPH	2007
BC-11 (Fugitive)	PE	BC-11	Connecting Conveyor	200 TPH	2007
TH-6 (Fugitive)	FE	TH-6	Gypsum Transfer House #6	200 TPH	2007
BC-12 (Fugitive)	PE	BC-12	Stacking Tripper Conveyor	200 TPH	2007
GSP (Fugitive)	FE	GSP	Gypsum Stockpile	15,600 tons	2007
PSR-1 (Fugitive)	FE	PSR-1	Traveling Portal Scraper Reclaimer	1,000 TPH	2007
BC-14 Fugitive)	PE	BC-14	Reclaim Conveyor	1,000 TPH	2007
TH-7 (Fugitive)	FE	TH-7	Transfer House #7	1,000 TPH	2007
BC-13 (Fugitive)	PE	BC-13	Bypass Conveyor	200 TPH	2007
BC-15 (Fugitive)	PE	BC-15	Connecting Conveyor	1,000 TPH	2007
TH-1 (Fugitive)	FE	TH-1	Transfer House #1	1,000 TPH	2007
BC-16 (Fugitive)	PE	BC-16	Transfer Conveyor	1,000 TPH	2007
BL-1 (Fugitive)	PE	BL-1	Barge Loader	1,000 TPH	2007
BC-14 (Fugitive)	PE	BC-14	Reclaim Conveyor Extension	1,000 TPH	2007

TH-8 (Fugitive)	FE	TH-8	Transfer House 8	1,000 TPH	2007
BC-19 (Fugitive)	PE	BC-19	Transfer Conveyor	1,000 TPH	2007
TH-9 (Fugitive)	FE	TH-9	Transfer House 9	1,000 TPH	2007
BC-20 (Fugitive)	PE	BC-20	Transfer Conveyor to 20	1,000 TPH	2007
TH-10 (Fugitive)	FE	TH-10	Transfer House 10	1,000 TPH	2007
BC-21 (Fugitive)	PE	BC-21	Transfer Conveyor to 21	1,000 TPH	2007
BUN-1 (Fugitive)		BUN-1	Clamshell Unloading Crane	1,000 TPH	2007
RH-4 (Fugitive)	WS, PE	RH-4	Gypsum Unloading Hopper	30 tons	2007
RP-1 (Fugitive)	FE	RP-1	Gypsum Rotary Plow	750 TPH	2007
BC-17 (Fugitive)	PE	BC-17	Dock/Connecting Conveyor	750 TPH	2007
TH-7 (Fugitive)	FE	TH-7	Transfer House #7	750 TPH	2007
BC-18 (Fugitive)	PE	BC-18	Bypass Conveyor	750 TPH	2007
TH-6 (Fugitive)	FE	TH-6	Transfer House #6	750 TPH	2007
3S - Limestone Mineral Processing					
VF-2 (Fugitive)	FE	VF-2	Limestone Reclaim Feeder 2	750 TPH	2007
VF-3 (Fugitive)	FE	VF-3	Limestone Reclaim Feeder 3	750 TPH	2007
BC-3 (Fugitive)	PE	BC-3	Limestone Tunnel Reclaim Conveyor	750 TPH	2007
FB-1 (Fugitive)		FB-1	Emergency Limestone Reclaim Feeder/Breaker	750 TPH	2007
TH-2 (Fugitive)	FE	TH-2	Limestone Transfer House 2	750 TPH	2007
BC-4 (Fugitive)	PE	BC-4	Limestone Silo A Feed Conveyor	750 TPH	2007
BC-5 (Fugitive)	PE	BC-5	Limestone Silo B Feed Conveyor	750 TPH	2007
BC-6 (Fugitive)	PE	BC-6	Limestone Silo C Feed Conveyor	750 TPH	Future
6E	BH	LSB-1	Limestone Silo A	900 Tons	2007
7E	BH	LSB-2	Limestone Silo B	900 Tons	2007
8E	BH	LSB-3	Limestone Silo C	900 Tons	Future
(Fugitive)	FE		Vibrating Bin Discharger (one per silo)	68.4 TPH	2007
LSWF-1 (Fugitive) LSWF-2 (Fugitive) LSWF-3(Fugitive)	FE	LSWF-1 LSWF-2 LSWF-3	Limestone Weigh Feeder (one per silo)	68.4 TPH	2007
(Fugitive)	FE		Wet Ball Mill (one per silo)	68.4 TPH	2007
4S - Dry Sorbent Material Handling					

(Fugitive)	FE		Truck Unloading Connection (2)	25 TPH	2007
10E	BH, FE	DSSB 1	Dry Sorbent Storage Silo #1	500 TPH	2007
11E	BH, FE	DSSB 2	Dry Sorbent Storage Silo #2	500 TPH	2007
(Fugitive)	FE		Aeration Distribution Bins	4.6 TPH	2007
(Fugitive)	FE		De-aeration Bins	4.6 TPH	2007
(Fugitive)	FE		Rotary Feeder	4.6 TPH	2007
5S - Coal Blending System					
HTS-1 (Fugitive)	FE	HTS-1	Transfer House #1	3,000 TPH	2007
HSC-1 (Fugitive)	PE	HSC-1	Stacking Conveyor #1	3,000 TPH	2007
HTS-2A (Fugitive)	FE	HTS-2A	Transfer House #2A	3,000 TPH	2007
HSC-2 (Fugitive)	PE	HSC-2	Stacking Conveyor #2	3,000 TPH	2007
HTS-3 (Fugitive)	FE	HTS-3	Transfer House #3	3,000 TPH	2007
HSC-3 (Fugitive)	PE	HSC-3	Stacking Conveyor #3	3,000 TPH	2007
SH-1 (Fugitive)	FE	SH-1	Stacking Hopper SH-1 Transfer to SC-3 (receive coal from plant radial stacker R9)	3,000 TPH	2007
HSC-3 to High Sulfur Pile (Fugitive) (CSA-2, existing)	Stacking Tube	HSC-3 to High Sulfur Pile (CSA-2, existing)	Transfer from Stacking Conveyor HSC-3 to High Sulfur Pile at existing North Yard Storage Area (CSA-2)	3,000 TPH	2007
HVF-1 (Fugitive)	FE	HVF-1	Coal Reclaim Feeder 1	800 TPH	2007
HVF-2 (Fugitive)	FE	HVF-2	Coal Reclaim Feeder 2	800 TPH	2007
HVF-3 (Fugitive)	FE	HVF-3	Coal Reclaim Feeder 3	800 TPH	2007
HVF-4 (Fugitive)	FE	HVF-4	Coal Reclaim Feeder 4	800 TPH	2007
HVF-1 through HVF-4 to HRC-1 (Fugitive) (Transfer)	FE	HVF-1 through HVF-4 to HRC-1 (Transfer)	Transfer from Vibrating Feeders HVF-1 through HVF-4 to Reclaim Conveyor HRC-1	1,600 TPH	2007
HRC-1 (Fugitive)	PE	HRC-1	Coal Tunnel Reclaim Conveyor	1,600 TPH	2007
HTS-2B (Fugitive)	FE	HTS-2B	Coal Transfer House #2B	1,600 TPH	2007
HRC-2 (Fugitive)	PE	HRC-2	Reclaim Conveyor #2	1,600 TPH	2007
HTS-4 (Fugitive)	FE	HTS-4	Coal Transfer House #4	1,600 TPH	2007
HRC-3 (Fugitive)	PE	HRC-3	Reclaim Conveyor #3	1,600 TPH	2007
HTS-5 (Fugitive)	FE	HTS-5	Coal Transfer House #5	1,600 TPH	2007
SB-1 (Fugitive)	FE	SB-1	Surge Bin #1	80 Tons	2007
HBF-1A (Fugitive)	PE	HBF-1A	Belt Feeder 1A	800 TPH	2007
HBF-1B (Fugitive)	PE	HBF-1B	Belt Feeder 1B	800 TPH	2007
HBF-1A/1B to BF-4E/4W (Fugitive)	FE	HBF-1A/1B to BF-4E/4W	Transfer from Belt Feeders HBF-1A and HBF-1B to Existing Coal Conveyors 4E and 4W	1,600 TPH	2007

6S, 7S - Emergency Quench Water System					
15E	FE	6S	Diesel Engine on Quench Pump #1	60 HP (approx.)	2007
16E	FE	7S	Diesel Engine on Quench Pump #2	60 HP (approx.)	2007
9S – Magnesium Hydroxide Material Handling System					
MHM-1	N/A	MHM-1	Magnesium Hydroxide Mix Tank #1	1000 Gal.	2007
MHM-2	N/A	MHM-2	Magnesium Hydroxide Mix Tank #2	1000 Gal.	2007
11S – Wastewater Treatment Material Handling					
Fugitive	FE		Truck Unloading Connection (2)	25 TPH	2007
24E	BH, FE		Lime Storage Silo #1	100 TPH	2007
25E	BH, FE		Lime Storage Silo #2	100 TPH	2007
Fugitive	Building Enclosure		Wastewater Treatment Cake Stockpile	3,600 Tons	2007
Fugitive	PE	FB-2	Filter Cake Feeder/Breaker	600 TPH	2007
Fugitive	PE	BC-22	Transfer Conveyor 22	600 TPH	2007
Fugitive	PE	TH-12	Transfer House #12	600 TPH	2007
Miscellaneous Other					
Tank #1	N/A	Tank #1	Ignition Oil Tank – S. of U1 Cooling Tower	1,500,000 Gal.	~1975
Tank #2	N/A	Tank #2	Ignition Oil Tank – N. of U2 Cooling Tower	500,000 Gal.	1971
Tank #3	N/A	Tank #3	Ignition Oil Tank – N. of U2 Cooling Tower	500,000 Gal.	1971
Tank #4	N/A	Tank #4	Used Oil Tank – S. of U1 Cooling Tower	1,000 Gal.	Relocated ~2004
Tank #5	N/A	Tank #5	Used Oil Tank – Tractor Shed	500 Gal.	~2000
Tank #6	N/A	Tank #6	Sulfuric Acid Tank – W. of Units 1&2	15,000 Gal.	1971
Tank #7	N/A	Tank #7	Ammonium Hydroxide Tank – W. of Units 1 &2	4,750 Gal.	1971
Tank #8	N/A	Tank #8	Diethylene Glycol Tank – N. of Station R-4	500 Gal.	~2002
Tank #9	N/A	Tank #9	Diethylene Glycol Tank – Station 3	300 Gal.	~2002
Tank #10	N/A	Tank #10	Diethylene Glycol Tank – Station R-4	300 Gal.	~2002
Tank #11	N/A	Tank #11	No.2 Fuel Oil Tank – Coal Transfer Station #3	1,000 Gal.	2007
Tank #12	N/A	Tank #12	No.2 Fuel Oil Tank – Coal Transfer Station R-2	3,000 Gal	~2004
Tank #13	N/A	Tank #13	No.2 Fuel Oil Tank – Coal Transfer Station R-4	3,000 Gal.	~2004
Tank #14	N/A	Tank #14	No.2 Fuel Oil Tank – Drain Receiver Tank	400 Gal.	1969
Tank #15	N/A	Tank #15	Gasoline Tank – Main Plant Entrance	8,000 Gal.	1991
Tank #16	N/A	Tank #16	Diesel Fuel Tank – Tractor Shed	10,000 Gal	1991
Tank #17	N/A	Tank #17	Turbine Oil Tank – U1	~14,000 Gal.	1971

Tank #18	N/A	Tank #18	Turbine Oil Tank – U2	~14,000 Gal.	1971
Tank #19	N/A	Tank #19	Lube Oil Tank – U1	~20,000 Gal.	1971
Tank #20	N/A	Tank #20	Lube Oil Tank – U2	~18,000 Gal.	1971
Tank #21	N/A	Tank #21	Chemical Cleaning Solution Tank	1,000,000 Gal.	1989
Tank #22	N/A	Tank #22	EHC System Oil Tank – U1	200 Gal.	1971
Tank #23	N/A	Tank #23	New Lube Oil Tank – U1	1,000 Gal.	1971
Tank #24	N/A	Tank #24	Used Oil Bulk Tank – U1	275 Gal.	~2002
Tank #25	N/A	Tank #25	EHC System Oil Tank – U2	625 Gal.	1971
Tank #26	N/A	Tank #26	New Lube Oil Tank – U2	1,000 Gal.	1971
Tank #27	N/A	Tank #27	Used Oil Bulk Tank – U2	275 Gal.	~2002
Tank #28	N/A	Tank #28	Diesel Fire Pump Fuel Tank – U1	300 Gal.	1971, Replaced in 2023
Tank #29	N/A	Tank #29	Diesel Fire Pump Fuel Tank – U2	300 Gal.	1971, Replaced in 2024
Tank #30	N/A	Tank #30	3 Compartment Oil Tank – Tractor Shed Oil Room	920 Gal.	~1995
Tank #31	N/A	Tank #31	Single Compartment Oil Tank – Tractor Shed	560 Gal.	~1995
Tank #32	N/A	Tank #32	Waste Oil Tank – Tractor Shed Oil Room	500 Gal.	~2000
Tank #33	FE	Tank #33	Urea Receiving Hopper	45 Tons	2007
Tank #34	N/A	Tank #34	No.2 Fuel Oil Tank – Drain Receiver Tank – overflow tank	1,000 Gal.	2001
Tank #35	N/A	Tank #35	TK103-100 Urea Solution Storage Tank	200,000 Gal.	2007
Tank #36	N/A	Tank #36	TK102-100 Urea Mix Tank	2,700 Gal.	2007
Tank #37	N/A	Tank #37	CPS Lime Slurry Tank #1	750 Gal.	2007
Tank #38	N/A	Tank #38	CPS Lime Slurry Tank #2	750 Gal.	2007
Tank #39	N/A	Tank #39	CPS Equalization Tank #1	254,513 Gal.	2007
Tank #40	N/A	Tank #40	CPS Equalization Tank #2	254,513 Gal.	2007
Tank #41	N/A	Tank #41	CPS Ferric Chloride Mix Tank #1	9,200 Gal.	2007
Tank #42	N/A	Tank #42	CPS Ferric Chloride Mix Tank #2	9,200 Gal.	2007
Tank #43	N/A	Tank #43	CPS Ferric Chloride Bulk Storage Tank	8,800 Gal.	2007
~~Tank #44~~	~~N/A~~	~~Tank #44~~	~~CPS Acid Bulk Storage Tank~~	~~10,575 Gal.~~	~~2007~~ **(Removed)**
Tank #45	N/A	Tank #45	CPS Polymer Totes (2)	225 Gal. (each)	2007
Tank #46	N/A	Tank #46	Emergency Quench Pump #1 Diesel Tank	70 Gal.	2007
Tank #47	N/A	Tank #47	Emergency Quench Pump #2 Diesel Tank	70 Gal.	2007
Tank #48	N/A	Tank #48	Aux. Boiler Collection Tank Return UST	500 Gal.	2006

Tank #49	N/A	Tank #49	No. 2 Fuel Tank – SW Corner of CSA-2	2000 Gal.	2008
Tank #50	N/A	Tank #50	Gypsum Storage Building Fuel Oil Tank	1000 Gal.	2009
Tank #51	N/A	Tank #51	Highway Grade Diesel Tank #1	1000 Gal.	2011
Tank #52	N/A	Tank #52	Limestone Storage Pile Diesel Tank #1	500 Gal.	2011
Fugitive	Enclosure		Rock Salt Storage Pile (roadway ice control)	600 Tons	2010 and 2014
Tank #53	N/A	Tank #53	Landfill Building Furnace Fuel Oil Tank	2000 Gal.	2018
Tank #54	N/A	Tank #54	Landfill Gasoline Tank	520 Gal.	2018
Tank #55	N/A	Tank #55	Kerosene Tank	1,000 Gal.	2015
Tank #56	N/A	Tank #56	CPS Coagulant Tank	5,000 Gal.	2019
Tank #57	N/A	Tank #57	Unit 1 Scale Inhibitor Tank	3,500 Gal.	2015
Tank #58	N/A	Tank #58	Unit 2 Scale Inhibitor Tank	3,500 Gal.	2015
Tank #59	N/A	Tank #59	Unit 1 Dispersant Tank	5,000 Gal.	2015
Tank #60	N/A	Tank #60	Unit 2 Dispersant Tank	5,000 Gal.	2015
Tank #61	N/A	Tank #61	Unit 1 Ferric Chloride Tank	1,500 Gal.	2015
Tank #62	N/A	Tank #62	Unit 1 Ferric Chloride Tank	2,500 Gal.	2015
Tank #63	N/A	Tank #63	FGD corrosion inhibitor tank	5,000 Gal.	2015
	N/A		Landfill Building Fuel Oil Fired Furnace Clean Burn Model CB-3250	0.325 MMBtu/hr	2018
Tank #64	N/A	Tank #64	Bioreactor Nutrient Tank	12,575 Gal.	2024
Tank #65	N/A	Tank #65	Bioreactor Hydrochloric Acid Tank	6,000 Gal.	2024
Tank #66	N/A	Tank #66	WW Pond Sulfuric Acid Tank	14,500 Gal.	2023
Tank #67	N/A	Tank #67	WW Pond Sodium Hydroxide Tank	20,300 Gal.	2023
Tank #68	N/A	Tank #68	WW Pond Organosulfide Tank	6,400 Gal.	2023
Tank #69	N/A	Tank #69	WW Pond Polymer Tank	1,360 Gal.	2023

[1]For 45CSR13 permitted sources, the numbering system used for the emission points, control devices, and emission units should be consistent with the numbering system used in the 45CSR13 permit. For grandfathered sources, the numbering system should be consistent with registrations or emissions inventory previously submitted to DAQ. For emission points, control devices, and emissions units which have not been previously labeled, use the following 45CSR13 numbering system: 1S, 2S, 3S,... or other appropriate description for emission units; 1C, 2C, 3C,... or other appropriate designation for control devices; 1E, 2E, 3E, ... or other appropriate designation for emission points.

Attachment E

Emission Unit Forms

ATTACHMENT E - Emission Unit Form

Emission Unit Description Unit 1 Main Boiler

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:** ESP, SCR, FGD
Unit 1 – ML1	Unit 1 Boiler	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
Unit 1 is coal-fired EGU boiler that also utilizes oil for supplemental firing. Oil use includes, but is not limited to, periods of start-up, shutdown, stabilization and emergency operations. The boiler may also periodically combust non-hazardous material such as demineralizer resins, chemical cleaning solution, on-spec used oil, etc. The nominal design of the Unit 1 boiler is 7,020 mmBtu/hr. Coal is delivered to the site via river barge, rail car, truck or conveyor. Oil is delivered to the site via river barge or truck.

Manufacturer:	**Model number:**	**Serial number:**
Foster Wheeler	2-85-303	Custom
Construction date: MM/DD/YYYY	**Installation date:** 05/31/1971	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Nominal 7020 mmBtu/Hr (270 TPH with 13,000 BTU/lb Coal Supply) This heat input value is for operation at the nominal boiler rating. Boiler design enables the boiler to be operated above the nominal rated capacity.

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
Nominal 5,289,000 lb/hr Steam	Nominal 46,331,640,000 lb/yr Steam	8760 hr/yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? X__Yes ___ No	**If yes, is it?** X__ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 8590 mmBtu/hr (rating used to model full load operation for FGD permit determination)	**Type and Btu/hr rating of burners:** LNB – Foster Wheeler

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Primary: Coal; Secondary: Oil; The steam generator is capable of burning coal, and will utilize fuel oil for start-up, shutdown and for flame stabilization. Other materials burned included non-hazardous water treatment resins, chemical cleaning solution, on spec used oil, etc.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Coal (Bit.)	4.5 lb/mmBtu	12.5%	13,000 BTU/lb
Oil	0.5%	N/A	19,750 BTU/lb

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	531	2324.5
Nitrogen Oxides (NO_X)	4139	18131
Lead (Pb)	0.42	1.8
Particulate Matter ($PM_{2.5}$)	105	461.2
Particulate Matter (PM_{10})	237	1037.7
Total Particulate Matter (TSP)	351	1537.4
Sulfur Dioxide (SO_2)	10243	44862.6
Volatile Organic Compounds (VOC)	64	279
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Arsenic	0.64	2.8
Beryllium	1.53	6.7
Chromium	0.23	1.0
Cobalt	0.08	0.4
Manganese	0.43	1.9
Mercury	0.24	1.1
Nickel	0.19	0.8
Selenium	5.53	24.2
Hydrogen Chloride	1408.3	6168.3
Hydrogen Fluoride	122.3	535.6
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 4.0 through 4.1 (see Attachment I) : Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 4.2 through 4.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Unit 2 Main Boiler

Emission unit ID number: Unit 2 – ML2	**Emission unit name:** Unit 2 Boiler	**List any control devices associated with this emission unit:** ESP, SCR, FGD

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
Unit 2 is coal-fired EGU boiler that also utilizes oil for supplemental firing. Oil use includes, but is not limited to, periods of start-up, shutdown, stabilization and emergency operations. The boiler may also periodically combust non-hazardous material such as demineralizer resins, chemical cleaning solution, on-spec used oil, etc. The nominal design of the Unit 1 boiler is 7,020 mmBtu/hr. Coal is delivered to the site via river barge, rail car, truck or conveyor. Oil is delivered to the site via river barge or truck.

Manufacturer: Foster Wheeler	**Model number:** 2-85-304	**Serial number:** Custom
Construction date: MM/DD/YYYY	**Installation date:** 05/31/1971	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Nominal 7020 mmBtu/Hr (270 TPH with 13,000 BTU/lb Coal Supply). This heat input value is for operation at the nominal boiler rating. Boiler design enables the boiler to be operated above the nominal rated capacity.

Maximum Hourly Throughput: Nominal 5,280,000 lb/hr Steam	**Maximum Annual Throughput:** Nominal 46,252,800,000 lb/yr Steam	**Maximum Operating Schedule:** 8760 hr/yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? X__Yes ___ No	**If yes, is it?** X__ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 8,481 mmBtu/hr (rating used to model full load operation for FGD permit determination)	**Type and Btu/hr rating of burners:** LNB – Foster Wheeler

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Primary: Coal; Secondary: Oil; The steam generator is capable of burning coal, and will utilize fuel oil for start-up, shutdown and for flame stabilization. Other materials burned include non-hazardous water treatment resins, chemical cleaning solution, on spec used oil, etc.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Coal	4.5 lb/mmBtu	12.5%	13,000 BTU/lb
Oil	0.5%	N/A	19,750 BTU/lb

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	531	2323.5
Nitrogen Oxides (NO_X)	4139	18131
Lead (Pb)	0.42	1.8
Particulate Matter ($PM_{2.5}$)	105	461.2
Particulate Matter (PM_{10})	237	1037.7
Total Particulate Matter (TSP)	351	1537.4
Sulfur Dioxide (SO_2)	10243	44862.6
Volatile Organic Compounds (VOC)	64	279
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Arsenic	0.64	2.8
Beryllium	1.53	6.7
Chromium	0.23	1.0
Cobalt	0.08	0.4
Manganese	0.43	1.9
Mercury	0.24	1.1
Nickel	0.19	0.8
Selenium	5.53	24.2
Hydrogen Chloride	1408.3	6168.3
Hydrogen Fluoride	122.3	535.6
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 4.0 through 4.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 4.2 through 4.5 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Auxiliary Boiler 1

Emission unit ID number:	Emission unit name:	List any control devices associated with this emission unit:
Aux ML1	Auxiliary Boiler 1	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
Auxiliary Boiler 1 is an oil-fired non-EGU boiler. Use of the auxiliary boiler includes, but is not limited to heating, startup and shutdown purposes. The nominal design of Auxiliary Boiler 1 is 663 mmBtu/hr. Oil is delivered to the site via river barge or truck.

Manufacturer:	Model number:	Serial number:
Foster Wheeler	SD-25	Custom
Construction date: MM/DD/YYYY	**Installation date:** 1970, Rebuild 2012	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Nominal 663 mmBtu/Hr

Maximum Hourly Throughput:	Maximum Annual Throughput:	Maximum Operating Schedule:
355,000 lb/hr steam	310,980,000 lb/yr steam	876 hr/yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? X__Yes ___ No	If yes, is it? X__ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: Nominal 663 mmBtu/hr	**Type and Btu/hr rating of burners:** Front Wall

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Primary: Oil

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Oil	0.3%	N/A	19,750 Btu/lb

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	206.8	90.6
Nitrogen Oxides (NO_X)	99.5	43.56
Lead (Pb)	0.006	0.0026
Particulate Matter ($PM_{2.5}$)	1.18	0.52
Particulate Matter (PM_{10})	4.74	2.07
Total Particulate Matter (TSP)	9.47	4.15
Sulfur Dioxide (SO_2)	39.78	17.42
Volatile Organic Compounds (VOC)	0.95	0.41
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Arsenic	0.0003	0.001
Beryllium	0.0002	0.001
Chromium	0.0002	0.001
Manganese	0.0004	0.002
Mercury	0.0002	0.001
Nickel	0.0002	0.001
Selenium	0.001	0.004
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 5.0 through 5.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 5.2 through 5.5 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Coal and Ash Handling		
Emission unit ID number: Emission Group 003	**Emission unit name:** Coal & Ash Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, mechanical controls, water sprays.
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The coal and ash handling system consists of a barge unloader, railcar unloader, chutes and conveyors, transfer stations, crushers, storage piles and silos for coal, as well as a wet ash handling system for ash. Note that a project is currently underway to convert the wet fly ash handling system to a dry fly ash handling system. See attached description of the coal and ash handling systems.		
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Coal transfer capacity (nominal) – up to 4,000 ton/hr; Fly Ash Handling – up to 980,000 tons per year.		
Maximum Hourly Throughput: Coal: Nominal 3,000 ton/hr Fly Ash: 720 ton/hr	**Maximum Annual Throughput:** Coal - Nominal 26,280,000 ton/yr Fly Ash – 980,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr
***Fuel Usage Data* (fill out all applicable fields)**		
Does this emission unit combust fuel? ___Yes X__ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A		
Describe each fuel expected to be used during the term of the permit.		

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	7.2	28.6
Particulate Matter (PM_{10})	36.1	135.8
Total Particulate Matter (TSP)	92.5	318.4
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Coal and Ash Handling Description:

- **Mitchell Plant Coal Handling:**

  General Description:
  Normally, coal is received at the Mitchell Plant by river barge, rail car, truck or conveyor and is placed on the coal storage piles or transported to the coal silos for immediate plant use.

  Railcar Dumping System (Station R-6):
  Coal delivered to Mitchell Plant by rail car is unloaded at the rail car dumper and then transported by a feeder/conveyor system to Station R-2

  Coal Barge Unloader (Station R-1):
  Coal delivered to Mitchell Plant by river barge is unloaded at Station R-1 (coal barge unloader) and then transported via multiple conveyors to Station R-2

  Station R-2:
  Coal from the rail unloading and barge unloading systems enters Station R-2, where it can be crushed and then transferred to conveyor that transports it to Station R-3.

  Station R-3:
  At Station R-3, coal can be placed on a conveyor that transports it to Station R-4.

  Station R-4:
  At Station R-4, coal is sampled and then can be transferred to either a conveyor that transports the coal to Station 2 or to a series of conveyors ending with a radial stacker that discharges the coal to the North Yard long-term storage pile.

  Station 2:
  At Station 2, coal is transferred to a conveyor and then to a radial stacker for distribution on the South Yard active surge pile.

  Station R-7:
  Station R-7 is located under the North Yard storage pile. At Station R-7, coal is pushed by dozer into a reclaim hopper where it is transferred via a feeder/conveyor system to Station R-4. As described previously, coal that enters Station R-4 can be diverted vial conveyors to the Radial Stacker at Station 2 and placed on the South Yard surge pile.

  Stations 3A, 3B, and 3C:
  Stations 3A, 3B and 3C are located under the South Yard surge pile. Coal is reclaimed from the surge pile through reclaim hoppers at each of these Stations and transferred via a series of feeders/conveyors to Station 3.

  Station 1A:
  Station 1A is also located under South Yard surge pile. Coal that is reclaimed from the South Yard surge through reclaim hoppers at Station 1A can be crushed before being transferred via a feeder and conveyor to Station 1B.

  Station 1B:
  At Station 1B, coal is transferred to a conveyor that transports the coal to Station 2. As described previously, coal that enters Station 2 can be transferred onto the active surge pile via the radial coal stacker and then transferred via conveyors from the reclaim hoppers to Station 3.

  Station 3:
  At Station 3, coal is transferred to conveyors that transport the coal to Station 4.

  Station 4:

At Station 4, coal is sampled and then transferred to either the Unit 2 silo filling system or to conveyors that transport the coal to Station 5.
Unit 2 Silo Filling:
Coal that is diverted from Station 4 to the Unit 2 silo filling system is discharged into the Unit 2 silos via a series of conveyors and diversion gates.

Station 5 and Unit 1 Silo Filling:
At Station 5, coal is diverted to a series of conveyors and diversion gates that discharge coal into the Unit 1 silos.

Emergency Conveyor System:
Emergency conveyor systems, located above the Unit 1 and Unit 2 silos provide emergency filling of the silos if, for any reason, the primary system is inoperable.

Methods of Compliance:
Fugitive emissions from the coal handling and storage systems are controlled by various methods. Typical measures employed at Mitchell Plant to control fugitive dust emissions from the coal handling and coal storage facilities include, but are not limited to: full and partial transfer point enclosures, coal wetting, full and partially covered conveyors, compaction, and delivery management techniques. The delivery management techniques generally minimize the amount of coal in storage: however, coal delivery capabilities and practices may vary throughout the year. For example, stockpiles may be periodically increased in size in anticipation of coal unloader outages or temporary mining shutdowns. The Mitchell Plant employs management techniques to control and minimize fugitive emissions from the coal handling system and the coal storage areas. The coal handling and storage areas are inspected periodically in accordance with Title V requirements to insure that compliance with fugitive emissions regulations is being maintained.

- **Mitchell Plant Ash Handling:**

Fly Ash Handling Description:
The Mitchell Plant fly ash removal system conveys fly ash collected in the electrostatic precipitator hoppers. Fly ash is then removed from the hoppers by a vacuum conveying system that flows into the dry fly ash handling system. A description of the dry fly ash system follows.

The Mitchell Plant dry fly ash handling system conveys dry, free flowing Fly Ash and Economizer Ash from Units 1 and 2 to three concrete Fly Ash Silos for storage and transport. The overall handling system is composed of three major processes: Unit 1 Fly Ash Removal System, Unit 2 Fly Ash Removal System and the Fly Ash Silo System. Additionally, a dry fly ash landfill and associated haul road are utilized for disposal of the fly ash.

Unit 1 Fly Ash Removal System
The Unit 1 Fly Ash Removal System includes the ash handling Vacuum Conveying System from the precipitator boxes and Economizer hoppers to the Vacuum/Pressure Transfer Stations and the ash handling Pressure Conveying System to the Fly Ash Silos.

There are two Vacuum Conveying Systems, one per precipitator box, provided to convey the ash from the Fly Ash hoppers and the Economizer Ash hoppers (handled by Box 1 ash handling vacuum system) and are operated independently of the other System. Each System is designed to convey to one of two dedicated Vacuum/Pressure Transfer Stations (TS-1A, TS-1B or TS-1C, TS-1D). An automatic Transfer Station crossover exists for each conveying System when one Transfer Station is shut down for maintenance. There are a total of four Transfer Stations for Unit 1. A Transfer Station consists of one Filter/Separator assembly and two feeder assemblies.

The vacuum source for the Vacuum Conveying System is supplied by one of three motor driven Mechanical Exhausters (ME-1A, ME-1B, ME-1C). The three Mechanical Exhausters are connected such that one is dedicated to each System and one is a spare that can be used by either System. The mixture of ash and air is conveyed in conveyor lines in a dry state to the Filter/Separator of the selected Transfer Station where ash is removed from the air stream and dumped into the feeder assemblies for pressure conveying to the Fly Ash Silo System for storage and transport. The Filter/Separator is intended to control particulate emissions from the conveying air. When conveying air leaves the separating equipment, it passes through the Mechanical Exhauster and discharges to atmosphere.

There are two Pressure Conveying Systems, one for each unit (one for unit 1 and one for unit 2) serving a pair of Transfer Stations, provided to convey the ash from the Transfer station feeder assemblies to the Fly Ash Silos. The two systems are operated independently of each other. A common spare pressure conveying line (with automatic crossover) is provided for both conveying Systems. Therefore, there are three pressure conveying lines routed to the Fly Ash Silos.

Conveying air for each Pressure System is supplied by one of three motor driven Fly Ash Conveying Compressors. The three Compressors are connected such that one is dedicated to each System and one is a spare that can be used by either System.

Two feeder assemblies are located under each Filter/Separator. Each feeder assembly receives material from the Filter/Separator at low pressure and introduces it into the pressurized conveyor line. The row of feeder assemblies' empty, in a timed sequence, into the main conveying line. Here, the material is mixed with the conveying air and is transported to the Fly Ash Silos.

The material is collected and stored in the Silos, while the conveying air is vented to atmosphere through a Bin Vent Filter (BVF-A, BVF-B, BVF-C). Each storage silo is equipped with a bin vent filter. The bin vent filter is intended to control particulate emissions from the displaced air that is discharged from the silos. The air discharging through the bin vent filter is a result of the conveying air, dry unloader vent fan air, the air displacement caused by filling the silo with fly ash, the air displacement caused by expansion due to temperature difference, and also from fly ash fluidizing air that is blown into the bottom of the storage silo.

Unit 2 Fly Ash Removal System
The Unit 2 Fly Ash Removal System is similar to the Unit 1 Fly Ash Removal System.
Unit 2 Mechanical Exhausters (ME-2A, ME-2B, ME-2C)
Transfer Stations (TS-2A, TS-2B or TS-2C, TS-2D)

Fly Ash Silo System
The Fly Ash Silo System includes three concrete Fly Ash Silos, each equipped with its own dedicated controlled Silo Fluidizing System, Silo Dry Ash Unloading System and Silo Conditioned Ash Unloading System.

The material collected and stored in the Fly Ash Silos can be unloaded into trucks for removal to a disposal point in either a dry or conditioned state. Ash is unloaded from a Silo in a dry state into a closed-top tank truck with a Telescopic Spout (TC-A, TC-B, TC-C). Each spout is equipped with a vent module (TCV-A, TCV-B, TCV-C). If it is not desired to unload the ash in a dry state, ash is unloaded from a Silo in a conditioned state into an open-top truck with a Pin Paddle Mixer/Unloader (WFA-AA, WFA-BA, WFA-CA, WFA-AB, WFA-BB, WFA-CB). The trucks, containing conditioned fly ash, are used to transport the ash to the Mitchell Plant dry fly ash landfill that was constructed in conjunction with the dry fly ash project.

Bottom Ash Handling Description:
The Mitchell Plant bottom ash removal facilities are designed as wet transport and storage systems and therefore have no fugitive emissions. Slag shed from the furnace walls or dislodged by slage blowers falls through the furnace hopper throats and is collected in ash hoppers. Bottom ash accumulated in the ash hoppers is removed periodically by sluicing it from the hoppers through an ash gate and bottom ash jet pump into an ash disposal line. The ash disposal line carries the mixture to the bottom ash disposal ponds.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Limestone Handling and Processing

Emission unit ID number: Emission Groups 1S	**Emission unit name:** Limestone Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, water sprays.

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The limestone handling system consists of a barge unloader, chutes and conveyors, transfer stations, and storage piles for limestone. See attached description of the limestone handling system.

Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Limestone transfer capacity (nominal) – up to 750 ton/hr

Maximum Hourly Throughput: Nominal 750 ton/hr	**Maximum Annual Throughput:** Nominal 1,100,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes X__ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.67	0.52
Particulate Matter (PM_{10})	4.62	3.68
Total Particulate Matter (TSP)	10.30	8.53
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Limestone Handling and Processing Description:

Limestone Handling:
The limestone handling system is the portion of the limestone supply system that is not applicable under 40 CFR 60 Subpart OOO NSPS regulations.

Limestone will be delivered to the Mitchell Plant site in river barges having capacities of up to 2000 tons. New barge docking river cells will be installed parallel to the shoreline near the existing fuel oil unloading pier to store the incoming and outgoing fleet of limestone barges. A barge haul system will be installed to position the barges for unloading. The limestone barge unloading equipment, consisting of a 1000 ton per hour free digging capacity clamshell crane unloader (750 ton per hour average unloading rate), and a receiving hopper/vibratory feeder will be mounted on the new large diameter river cells.

Limestone will be transferred from the clamshell crane Unloader BUN-1 to the fixed, cell mounted hopper RH-1. The hopper RH-1 will discharge via a vibrating feeder VF-1 to the tail end of the limestone dock/connecting conveyor BC-1. The limestone dock/connecting conveyor BC-1 will transfer the limestone from the unloading dock to the first limestone/gypsum Transfer House #1 (TH-1) on shore. Dust will be controlled at the barge unloading operation (hopper load-in area) using a dry fog dust suppression system and windscreens. Nozzles will be mounted around the top of the unloading hopper generating fog to keep any dust generated by dropping the limestone into the hopper, inside the hopper. Further, the dock/connecting conveyor will utilize a ¾ cover to minimize fugitive dust.

At Transfer House TH-1, the limestone will be transferred from the dock/connecting conveyor BC-1 to the storage-pile stacking conveyor BC-2. The stacking conveyor BC-2 will convey the limestone to the active/long-term storage area creating the limestone storage pile (LSSP). The limestone storage pile will be uncovered and have a total capacity of approximately 41,300 tons. The limestone storage pile (LSSP) will have a capacity of approximately 15-days at a generator capacity factor of 100%. The long-term portion of the storage pile will be constructed by moving limestone from the active portion of the pile with mobile equipment to place it in the long-term storage portion of the pile. At the Transfer House TH-1, fugitive dust will be controlled with the use of fully enclosed chutework located within an enclosed building. The chutes incorporate closed loading skirts with adjustable rubber seals to minimize free air flow across the chute. The stacking conveyor BC-2 utilizes a ¾ cover to minimize fugitive dust and discharges to the limestone storage pile LSSP via a concrete stacking tube ST-1.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Limestone Handling and Processing

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
Emission Groups 3S	Limestone Processing	Conveyor covers, partial and full enclosures, baghouses, water sprays.

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The limestone processing system consists of chutes and conveyors, transfer stations, ball mills, and silos for limestone. See attached description of the limestone processing system.

Manufacturer:	**Model number:**	**Serial number:**
Various	Custom	N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Limestone transfer capacity (nominal) – up to 750 ton/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
Nominal 750 ton/hr	Nominal 1,100,000 ton/yr	8760 hrs/yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes X__ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	1.14	0.82
Particulate Matter (PM_{10})	7.50	5.40
Total Particulate Matter (TSP)	15.85	11.43
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used. The only exception is that baghouse potential emissions were adjusted to reflect a more reasonable potential emission total. Previously, the baghouse emissions were calculated assuming dust loading of the control device was equal to the maximum that the device could handle. The adjustment involves calculating a dust loading that is equal to the maximum that the device will see in the particular installation.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Limestone Processing Description:

Non-Metallic Mineral (Limestone) Processing System:
The “Non-Metallic Mineral Processing” system is the portion of the limestone supply/processing system that is applicable under 40 CFR 60 Subpart OOO NSPS regulations.

Limestone will be reclaimed from the active conical pile through two below grade vibrating pile drawdown hoppers DH-1 and DH-2 that discharge onto two reclaim feeders VF-2 and VF-3. The reclaim feeders VF-2 and VF-3 will discharge onto the tunnel reclaim conveyor BC-3. The tunnel reclaim conveyor BC-3 will discharge onto the silo “A” feed conveyor BC-4. The silo “A” feed conveyor BC-4 terminates in the limestone silo enclosure above the northernmost limestone storage silo LSB-1.

Each of the reclaim feeders (VF-2 and VF-3) will be completely enclosed with loading skirts. The portion of the tunnel reclaim conveyor BC-3 that is located above ground as well as the silo “A” feed conveyor BC-4 utilize ¾ covers to minimize fugitive dust. Each of the transfer points utilizes fully enclosed chutework located within an enclosed building. The chutes incorporate closed loading skirts with adjustable rubber seals between the skirtboard and the loaded belt.

An alternate limestone reclaim system has been designed into the Mitchell project. The alternate reclaim system is used when the reclaim feeders VF-2 and VF-3 are out of service for maintenance or repair or for handling limestone during periods of time that it may be frozen in clumps. The system consists of a feeder/breaker to receive limestone directly from under the storage pile or from an end loader. The feeder/breaker discharges to the limestone tunnel reclaim conveyor BC-3. The limestone tunnel reclaim conveyor can then transfer the limestone to the normal limestone feed conveyors

Limestone from the silo “A” feed conveyor BC-4 can be fed directly into the northernmost limestone silo LSB-1, or can be diverted to the silo “B” feed conveyor BC-5 via a diverter gate. The silo “B” feed conveyor BC-5 will convey the material to limestone silo LSB-2 or to the future silo “C” feed conveyor BC-6 via a diverter gate. Future silo “C” feed conveyor BC-6 will convey limestone to future limestone silo LSB-3. Each of the silo feed conveyors utilize a ¾ cover to minimize fugitive dust and each of the transfer points utilize fully enclosed chutework located within an enclosed building. The chutes incorporate closed loading skirts with adjustable rubber seals between the skirtboard and the loaded belt.

A bagfilter dust collector system will be provided to serve each of the silos. The limestone silo dust collector will have an open bottom and will be mounted on top of the limestone silo. All material collected on the bags falls via gravity into the limestone silo.

Three (including one future) independent FGD reagent preparation trains are provided, supplying complete redundancy support of 24-hour operation. Provisions have been made in the reagent preparation building design to expand the building and add the third (future) reagent preparation train (ball mill, classifier, ball mill product tank, ball mill slurry pumps, etc.) Each of the preparation trains supply limestone slurry to one recirculating feed loop that distributes slurry to both absorbers (one absorber per generating unit).

The limestone silos LSB-1, LSB-2, and LSB-3 (future) are used to store limestone for feed to the grinding system. Limestone drops by gravity from the vibrating bin discharger to the limestone weigh feeder LSWF-1, LSWF-2 and LSWF-3 (future), which conveys the limestone on a belt to the feed chute on the Wet Ball Mill. The limestone weigh feeder is a weighing, variable speed conveyor with its speed adjusted to set the mass flow. Make-up water is added to the feed chute and the mixture enters the wet ball mill.

The wet ball mill is a horizontal cylinder partially filled with steel balls that is rotated, tumbling the balls and grinding the limestone solids. The wet ball mill is motor driven through a gear reducer and is supplied with an air-operated clutch, which is engaged to start the mill once the mill motor is in operation. The clutch may also be used to stop the ball mill operation without stopping the motor. The size of the limestone particles is reduced in the ball mill by a rotating charge of steel balls. The limestone slurry overflows from the ball mill through the mill trommel and gravity feeds to the ball mill slurry tank. Limestone slurry density is maintained by controlling the make-up water flow rate to the classifier underflow launder proportional to the limestone feed rate. Each of the ball mill trains operates as its own separate loop.

The mill slurry pump transfers the limestone slurry from the mill slurry tank to the ball mill classifier. Two 100% ball mill slurry pumps per ball mill slurry tank are provided. Each limestone slurry classifier for the ball mills contains a battery of cyclones with a minimum of 25% spare capacity. The cyclone classifiers are arranged in a circular configuration and are fed from a cylindrical feed chamber. The feed chamber contains no internal partitions, baffles, and/or obstructions and provides a uniform and constant inlet pressure to each cyclone. Fine product slurry is separated from oversized particles of limestone by the classifier. The fine product collected in the overflow launder gravity flows to a common header, which in turn feeds the two limestone reagent slurry storage tanks, while the slurry containing oversized limestone is collected in the underflow launder and gravity flows back to the corresponding ball mill inlet for regrinding.

The two reagent slurry storage tanks are used to maintain a slurry inventory for feed to the absorbers and to provide the minimum suction pressure required by the reagent slurry feed pumps. The reagent slurry storage tank agitator maintains solids in suspension. The reagent slurry feed pump delivers slurry to one of two recirculating feed loop (one operating, one spare). The reagent slurry feed pump maintains a continuously recirculating flow in the loop and slurry velocities are constantly maintained while at the same time providing the required reagent feed to each absorber. Reagent slurry is added to each reaction tank at the base of the absorber in response to the SO2 concentration in the flue gas entering the wet FGD system and the pH of the reaction tank slurry.

The entire processing system beginning at the limestone silo fill point is enclosed in the processing building and all conveyors and transfer points are totally enclosed. Furthermore, the grinding operation occurs in water (slurry) and does not produce dust.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Gypsum Handling		
Emission unit ID number: Emission Groups 2S	**Emission unit name:** Gypsum Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, water sprays.
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The gypsum handling system consists of a barge loader and unloader, chutes and conveyors, transfer stations, and storage piles for gypsum. See attached description of the gypsum handling system.		
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Gypsum transfer capacity (nominal) – up to 1,000 ton/hr.		
Maximum Hourly Throughput: Nominal 1,000 ton/hr	**Maximum Annual Throughput:** Up to Nominal 1,912,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr
***Fuel Usage Data* (fill out all applicable fields)**		
Does this emission unit combust fuel? ___Yes X__ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A		

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.74	0.63
Particulate Matter (PM_{10})	11.78	4.38
Total Particulate Matter (TSP)	47.22	9.99
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining potential fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Gypsum Handling Description:

Gypsum Handling:
At the Mitchell facility, gypsum is created as a by-product of the Wet FGD Process. The gypsum will be collected from the four vacuum belt filters (including one future vacuum belt filter) that will discharge onto the Gypsum Vacuum Filter Collecting Conveyor BC-8. The Collecting Conveyor BC-8 will be located inside the dewatering building and will convey the material to the outside of the building and into Transfer House #3 where the gypsum is transferred to the gypsum Connecting Conveyor BC-9.

Connecting Conveyor BC-9 conveys the gypsum from Transfer House #3 to Transfer House #4 where it is transferred to gypsum Connecting Conveyor BC-10. Connecting Conveyor BC-10 conveys the gypsum from Transfer House #4 to Transfer House #5 where it is transferred to gypsum Connecting Conveyor BC-11. Connecting Conveyor BC-11 conveys the gypsum from Transfer House #5 to Transfer House #6 where it is transferred to either gypsum Stacking Tripper Conveyor BC-12 or gypsum Bypass Conveyor BC-13.

The head end of the stacking tripper conveyor BC-12 will be equipped with a traveling tripper able to discharge the gypsum to create the Gypsum Stockpile (GSP). The stockpile will be a 14,200-ton pile to store the gypsum prior to transfer for disposal or use. The gypsum stockpile will be located in a fully enclosed building. At the gypsum stockpile area, the gypsum is reclaimed from the and discharged to gypsum Reclaim Conveyor BC-14. Reclaim Conveyor BC-14 carries the gypsum to Transfer House #7 where it is transferred to gypsum Connecting Conveyor BC-15. As an alternative to carrying the gypsum on BC-14 to Transfer House #7, Reclaim Conveyor BC-14 will be designed as a reversible conveyor. As discussed later in this system description, Reclaim Conveyor BC-14 (operating in tpsrhe reverse mode) will be designed for transfer to a conveyor system supplying gypsum to an alternative destination where it will be utilized by a wallboard manufacturing facility.

As an alternative to placing the gypsum in the stockpile via the stacking tripper conveyor BC-12, Bypass Conveyor BC-13 can be used to transport the gypsum from Transfer House #6 to Transfer House #7 where it is transferred directly to Connecting Conveyor BC-15.

Connecting Conveyor BC-15 conveys the gypsum from Transfer House #7 to Transfer House #1 where is transferred to Transfer Conveyor BC-16. Transfer Conveyor BC-16 conveys the gypsum from Transfer House #1 to the gypsum Barge Loader BL-1. Barge Loader BL-1 transfers the gypsum to waiting river barges via a telescopic chute.

As mentioned previously, as an alternative to carrying the gypsum on BC-14 to Transfer House #7 and on to the barge loader BL-1 for loadout, Reclaim Conveyor BC-14 will be designed as a reversible conveyor. In the reverse mode, Reclaim Conveyor BC-14 will be designed for an extension of the gypsum handling system to allow gypsum transfer to a wallboard plant that will be constructed south of the Mitchell plant on the eastern side of West Virginia State Route 2.

At the gypsum stockpile area, the gypsum is reclaimed from the stockpile and discharged to gypsum Reclaim Conveyor BC-14. Reclaim Conveyor BC-14 (operating in the reverse mode) carries the gypsum to Transfer House TH-8 where it is transferred to gypsum Transfer Conveyor BC-19. Transfer Conveyor BC-19 conveys the gypsum to Transfer House TH-9 where it is transferred to gypsum Transfer Conveyor BC-20. Transfer Conveyor BC-20 conveys the gypsum to Transfer House TH-10 where it is transferred to gypsum Transfer Conveyor BC-21 crossing State Highway 2. Transfer Conveyor BC-21 conveys the gypsum to a future wallboard plant. As an alternative to transferring gypsum from Conveyor BC-20 to BC-21 in Transfer House TH-10, gypsum can also be diverted from Conveyor BC-20 to a small stockpile located at the base of Transfer House TH-10. The gypsum in the small stockpile will be reclaimed with end loaders and placed into dump trucks for transport. The purpose of the Transfer House TH-10 diversion gate and small stockpile is to provide a method of performing a periodic material weight test of the Conveyor BC-19 belt scale by re-weighing the material on a truck scale.

In order to support operation of the third-party wallboard plant, it will be necessary for additional gypsum to be delivered to the Mitchell Plant site in river barges having capacities of up to 1500 tons. The gypsum unloading system will utilize the same barge docking river cells, barge haul system and clamshell barge unloader as the limestone handling system. The barge unloader's clamshell bucket will be changed via a quick disconnect when switching from handling limestone to gypsum.

Gypsum will be transferred from the clamshell unloader BUN-1 to the fixed, cell mounted hopper RH-4. The unloading hopper RH-4 will discharge via a rotary plow RP-1 to the tail end of the gypsum dock/connecting conveyor BC-17. The gypsum dock/connecting conveyor BC-17 will transfer the gypsum from the unloading dock to Transfer House TH-7 on shore. Dust will be controlled at the barge unloading operation (hopper load-in area) using a dry fog dust suppression system and windscreens. Nozzles will be mounted around the top of the unloading hopper generating fog to keep any dust generated by dropping the gypsum into the hopper, inside the hopper.

At Transfer House TH-7, the gypsum will be transferred from the dock/connecting conveyor BC-17 to reclaim conveyor BC-14. As previously noted Reclaim Conveyor BC-14 will be designed as a reversible conveyor. In the reverse mode, Reclaim Conveyor BC-14 will be designed for allow gypsum transfer to a wallboard plant located south of the Mitchell plant as previously described.

As an alternative to transferring the gypsum from dock/connecting conveyor BC-17 to reclaim conveyor BC-14 for transport to the wallboard plant, the gypsum can be temporarily diverted to the gypsum stockpile area awaiting transfer to the wallboard plant. Under this scenario, gypsum from BC-14 is diverted to bypass conveyor BC-18 via diverter gate DG-8 inside Transfer House TH-7. Bypass conveyor BC-18 will transfer the material to stacking conveyor BC-12 inside Transfer House TH-6. As previously described, Stacking Conveyor BC-12, equipped with a traveling tripper, will stack the material into the gypsum stockpile.

Subsequently, as previously described, the gypsum is reclaimed from the stockpile and discharged to gypsum Reclaim Conveyor BC-14. Reclaim Conveyor BC-14 carries the gypsum to the gypsum conveyor extension to the wallboard plant.

Because the gypsum material will be damp (10% moisture by weight) from the filtering process, additional dust collection/suppression equipment is not provided. Nevertheless, the transfer points are designed as fully-enclosed transfer points and each of the outdoor conveyors utilize ¾ covers.

In the event that the normal gypsum handling system or portions of that system are out of service for maintenance/repair or if the gypsum product is of poor quality, provisions are being made to allow for emergency gypsum handling and disposal. The system consists primarily of an emergency stackout conveyor and stockpile. The gypsum collected from the four vacuum belt filters (including one future vacuum belt filter) is capable of being discharged onto the Gypsum Vacuum Filter Collecting Backup Conveyor BC-7. The Backup Collecting Conveyor BC-7 will be located inside the dewatering building and will convey the gypsum to the outside of the building where it will be stacked out to the emergency gypsum stockpile (GSPE). Gypsum stockpiled on the emergency pile will be reclaimed using front-end loaders and placed into dump trucks for transfer and disposal off-site or transfer to the normal gypsum stockpile (GSP). Since the material will be damp (10% moisture by weight) from the filtering process additional dust collection/suppression equipment is generally not necessary. Nevertheless, a ¾ cover will be utilized on the outdoor portion of Backup Collecting Conveyor BC-7.

ATTACHMENT E - Emission Unit Form			
Emission Unit Description WWT Handling			
Emission unit ID number: Emission Groups 11S	**Emission unit name:** WWT Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, baghouses, water sprays.	
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The waste water treatment handling system consists of truck unloading equipment, chutes and conveyors, transfer stations, lime storage silos, and storage piles for WWT cake. See attached description of the WWT handling system.			
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A	
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY	
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): WWT Cake transfer capacity (nominal) up to 600 ton/hr.			
Maximum Hourly Throughput: Nominal 600 ton/hr	**Maximum Annual Throughput:** Nominal 212,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr	
***Fuel Usage Data* (fill out all applicable fields)**			
Does this emission unit combust fuel? ___Yes X__ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired	
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**	
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A			
Describe each fuel expected to be used during the term of the permit.			
Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	14.95	0.87
Particulate Matter (PM_{10})	98.90	5.83
Total Particulate Matter (TSP)	219.56	14.63
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining potential fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

WWT Handling Description:

Waste Water Treatment Handling System:
The Wastewater Treatment System is used to treat the FGD wastewater prior to discharge of the water into the plant wastewater ponds. The wastewater treatment system is designed to reduce the effluent total suspended solids (TSS) concentration and maintain pH within an acceptable range. In addition to the TSS reduction, the treatment system is designed to be retrofitted should dissolved metals removal be required in the future. A generic treatment system process flow diagram has been supplied with this permit application.

The wastewater treatment system process includes equipment for dissolved sulfate desaturation, primary clarification, chemical addition, mixing and reaction, secondary clarification and filtration. Chemicals are added to the wastewater stream to improve the removal efficiency of the waste stream solids. The solids removed from the water stream are dewatered and stored for disposal. Dewatering is accomplished by filter presses (four, including one future). The design includes a provision to add a polymer at the inlet to the secondary clarifiers if required. Filter cake storage is in concrete bins, or rooms located beneath the filter presses. After desired dryness is achieved, the dewatered filter cake drops through a hole in the floor to a dewatered filter cake storage room. The projected amount of filter cake that will be generated on an annual basis is 212,000 tons/year.

Hydrated lime will be delivered to the site by pneumatic truck equipped with its own positive displacement rotary blower. The lime will be stored on site in two lime storage silos. A bag type bin vent filter, rated at 99.9 percent removal efficiency, will be provided to control escape of dust during transfer. Lime feeders and mix tanks will be located inside an enclosure below the silos.

Along with the lime, several other liquid chemicals will be delivered for use in the wastewater treatment system. These include ferric chloride and acids delivered by bulk tank truck along with organosulfate (future), and a polymer delivered by totes.

Disposal of the filter cake that will be generated by the wastewater treatment system will be accomplished by either placing the material in a barge, or in emergency situations, trucks for transport from the plant site. Each of the cake storage rooms (four) located beneath the filter presses (three with provisions for the fourth) will be open at one of the narrow ends for access by front-end loaders (i.e. the building enclosure consists of three walls and a roof). The filter cake will be removed by front-end loader and deposited into a covered stockpile at the loading end of a feeder/breaker FB-2, (drag flight-type conveyor). Feeder/breaker FB-2 will transport filter cake to the loading end of Transfer Conveyor BC-22 (belt type conveyor). Transport conveyor BC-22 will transport and discharge onto transfer conveyor BC-15 at Transfer House TH-12. Transfer conveyor BC-15 conveys the filter cake to Transfer House TH-1 where it is transferred to Transfer Conveyor BC-16. Transfer Conveyor BC-16 conveys the filter cake from Transfer House TH-1 to the Barge Loader BL-1. Barge Loader BL-1 transfers the filter cake to covered river barges via telescopic chute TC-1. Feeder/breaker FB-2 and Transfer Conveyor BC-22 will limit the maximum load out capacity to 600 tons per hour.

Filter cake storage will be accommodated inside the storage rooms (maximum of 900 tons each) beneath the filter presses as well as at the covered loading area of the feeder/breaker (300 tons). In the event barge load out of the filter cake is disrupted (i.e. high river water conditions stopping barge traffic) and the covered filter cake storage areas are filled, trucks will be used to transport the filter cake to GSPE, the gypsum emergency stockpile area, (2500 tons) normally used for gypsum and covered by tarps. In the extreme condition that the stockpile area is filled or if the facility is able to find a third party interested in purchasing the filter cake, trucks will be used to transport the filter cake off-site.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Coal Blending System			
Emission unit ID number: Emission Group 5S	**Emission unit name:** Coal Blending System	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures.	
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The coal blending system consists of a chutes and conveyors, transfer stations, and storage piles for coal. See attached description of the coal blending system.			
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A	
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY	
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Coal transfer capacity (nominal) – up to 3,000 ton/hr.			
Maximum Hourly Throughput: Nominal 3,000 ton/hr	**Maximum Annual Throughput:** Nominal 5,732,544 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr	
***Fuel Usage Data* (fill out all applicable fields)**			
Does this emission unit combust fuel? ___Yes X__ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired	
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**	
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A			
Describe each fuel expected to be used during the term of the permit.			
Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

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Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	3.65	4.76
Particulate Matter (PM_{10})	24.08	31.46
Total Particulate Matter (TSP)	50.92	66.52
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining potential fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.0 through Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.2 through 6.6 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Coal Blending System Description:

Coal Blending:
At the Mitchell Plant, the installation of the Wet FGD Process will allow the facility to burn a high-sulfur coal potentially available from a local mine. Nevertheless, it will likely be necessary to blend this high sulfur coal with a lower sulfur coal in order to obtain the coal qualities necessary for long-term, reliable combustion of the coal in the Mitchell Units. As such, a coal blending system is planned as an integral part of the FGD retrofit project.

The locally mined coal will enter the Mitchell site via the existing Consol Conveyor 3100. Conveyor 3100's discharge will be modified to transport the coal into the Mitchell coal handling system Transfer Station 1 (HTS-1). In Transfer Station #1, coal will be transferred from Conveyor 3100 to Stacking Conveyor HSC-1. Stacking Conveyor HSC-1 will transport the coal from Transfer Station #1 to Transfer Station #2A (HTS-2A) where the coal will be sampled and transferred to Stacking Conveyor HSC-2. Stacking Conveyor HSC-2 will transport the coal from Transfer Station #2A to Transfer Station #3 (HTS-3) where the coal will be transferred to Stacking Conveyor HSC-3. As an alternative, coal can be transferred to Stacking Conveyor HSC-3 from existing plant radial stacker R9 via Stacking Hopper SH-1.

Stacking Conveyor HSC-3 transfers the coal from Transfer Station #3 to the existing North Yard Storage area where it will be discharged through a new Stacking Tube (ST-1) to help form the high sulfur coal pile.

Coal will be reclaimed from the high sulfur coal pile via four under-pile drawdown hoppers/vibratory feeders. Each of the four vibratory feeders (HVF-1 through HVF-4) transfer coal to Tunnel Reclaim Conveyor HRC-1. Tunnel Reclaim Conveyor HRC-1 transfers the coal from under the pile to Transfer Station #2B where it is transferred to Reclaim Conveyor HRC-2. Reclaim Conveyor HRC-2 will transport the coal from Transfer Station #2 to Transfer Station #4 (HTS-4) where the coal will be transferred to Reclaim Conveyor HRC-3.

Reclaim Conveyor HRC-3 will transport the coal from Transfer Station #4 to Transfer Station #5 where it will discharge via a surge bin (SB-1) to two Belt Feeders (HBF-1A and HBF-1B). Belt Feeder HBF-1A will discharge coal onto existing plant coal conveyor 4E. Belt Feeder HBF-1B will discharge coal onto existing plant coal conveyor 4W. The blending of high sulfur coal with the lower sulfur coal will occur as the high sulfur coal is discharged from Belt Feeders HBF-1A and HBF-1B onto the existing conveyors 4E and 4W that carry low sulfur coal from the existing low sulfur coal pile.

In order to minimize fugitive dust generated from the coal blending system, each of the new transfer points will utilize fully enclosed chutework located within fully enclosed buildings. Furthermore, all outdoor conveyors will utilize ¾ covers. To further minimize fugitive dust generated from the coal blending system, conveyor to conveyor transfers will utilize controlled flow transfer chutes.

An alternate high sulfur coal reclaim system has been designed into the Mitchell project. The alternate reclaim system is used when the reclaim feeders (HVF-1 through HVF-4) are out of service for maintenance/repair or in the event it is necessary to separate frozen chunks of coal. The system consists of a feeder/breaker (FB) to receive coal directly from under the storage pile or from a front-end loader. The feeder/breaker discharges to the high sulfur coal tunnel reclaim conveyor (HRC-1). The high sulfur coal tunnel reclaim conveyor can then transfer the coal to the normal high sulfur coal reclaim conveyors.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Emergency Quench Water System

Emission unit ID number: Emission Units 6S and 7S	**Emission unit name:** Emergency Quench Water System	**List any control devices associated with this emission unit:** Full enclosures.

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The emergency quench water system consists of two diesel-engine driven quench pumps. See attached description of the emergency quench water system.

Manufacturer: Clark Diesel	**Model number:** JU 4R-UF-19 or equal	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 60 HP (approx.),

Maximum Hourly Throughput: 5.5 gal./hr (each)	**Maximum Annual Throughput:** 1,100 gal./yr (combined)	**Maximum Operating Schedule:** 200 hrs/yr (both engines combined)

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? _X_Yes ___ No	**If yes, is it?** _X_ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 0.8 mmBtu/hr nominal, 60 HP	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Diesel Fuel

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	0.2%	N/A	141,000 Btu/gal

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	1.52	0.08
Nitrogen Oxides (NO_X)	7.06	0.35
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.5	0.02
Particulate Matter (PM_{10})	0.5	0.02
Total Particulate Matter (TSP)	0.5	0.02
Sulfur Dioxide (SO_2)	0.46	0.02
Volatile Organic Compounds (VOC)	0.76	0.04
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors and manufacturer's information. For purposes of determining emissions associated with this equipment, the FGD Reg 13 permit application (permit R13-2608A) calculations were used. The estimated potential emissions represent the total emissions for both quench pumps combined.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 7.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 7.2 through 7.5 (see Attachment I): Where appropriate, revisions to existing language are noted

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Emergency Quench Water System Description:

Emergency Quench Water:
The existing air heaters are electric powered which could fail in case of plant power failure. In this case, the hot flue gas (600oF) could enter the absorbers. The emergency quench water system is designed to protect the absorbers by spraying water into the flue gas entering the absorber. The emergency quench system is activated in the event of a loss of on-site power. Two 100% pumps (including one spare) are provided for redundancy. The pumps are diesel engine driven to allow operation during blackout conditions. The service water tank provides the water supply.

Each emergency quench pump drive engine is rated at approximately 60 HP. No post-combustion pollution controls are utilized. Because these diesel engines are each rated at less than 500 brake horsepower, the engines are not subject to regulation under 40 CFR 63 Subpart ZZZZ (RICE rule).

The diesel fuel is supplied from a storage tanks holding approximately 70 gallons of fuel (one for each engine). Because the diesel fuel storage tanks are each less than 10,567 gallons capacity and will contain petroleum or organic liquids with a vapor pressure of 1.5 psia or less at storage temperature, and the emissions from both tanks, in the aggregate, are less than 2 tons per year, the tanks are considered de-minimis sources. De-minimis sources are not required to obtain construction permits under 45 CSR 13.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Dry Sorbent Handling System

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:** Full enclosures, baghouses.
Emission Group 4S	Dry Sorbent Handling Systems	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The dry sorbent handling system consists of truck unloading equipment, dry sorbent storage silos, etc. See attached description of the dry sorbent handling system.

Manufacturer:	**Model number:**	**Serial number:**
Various	Custom	N/A
Construction date:	**Installation date:**	**Modification date(s):**
MM/DD/YYYY	See equipment list in Attachment D	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 25 TPH Unloading, 500 Ton Dry Sorbent Silos

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
Nominal 25 ton/hr	Dry Sorbent 81,000 TPY Nominal	8760 Hr/Yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes _X_ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	31.31	136.86
Particulate Matter (PM_{10})	206.77	903.82
Total Particulate Matter (TSP)	438.69	1912.18
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory/permit limits and engineering knowledge. For purposes of determining potential fugitive emissions associated with this equipment, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Dry Sorbent Handling System Description:

SO_3 Mitigation System:
The installation and operation of a Selective Catalytic Reduction (SCR) system in conjunction with a wet FGD system on a boiler combusting high sulfur coal can potentially lead to increased concentrations of SO_3. Subsequently, the SO_3 reacts with moisture in the stack plume and the atmosphere to support the secondary formation of H_2SO_4. If not mitigated, the increase in SO_3 and subsequent increase in the formation of H_2SO_4 can impact the visible appearance of the discharge plume downwind of the stack.

The Mitchell Plant SCR installation utilizes a low conversion catalyst that helps minimize the conversion of SO_2 to SO_3 by the SCR system. Nevertheless, a supplemental SO_3 mitigation system is needed to help reduce SO_3 concentrations. Based on AEP's evaluation of various SO_3 mitigation systems at other AEP generating facilities, it was determined that the primary SO_3 mitigation system that would be constructed at Mitchell plant was a dry sorbent injection system. Hydrated Lime is the primarily used dry sorbent, with Trona being the secondary option. When Hydrated Lime is used, the dry sorbent injection system is supplemented with the injection of liquid Magnesium Hydroxide. For the purposes of this permit application, each of the options is described.

Dry Sorbent Handling:
The dry sorbent is injected through a pneumatic conveying system to ductwork downstream of the air preheaters as a means to reduce SO_3 in the stack plume. The dry sorbent feed rate for each Mitchell Unit will vary depending on the sorbent (Trona or Hydrated Lime) being utilized and the sulfur content of the fuel. The Trona feed rate is variable with an expected maximum feed of up to 4.6 tons per hour (per unit). The Hydrated Lime feed rate is also variable with an expected maximum feed of up to 4.4 tons per hour (per unit).

Two dry sorbent storage silos at approximately 500 tons each receive dry sorbent from self-unloading trucks. Bin vent filters are supplied on each silo for the filtered venting of the truck blow-off air and the silo's fluidizing air system. An aeration system, consisting of open-type airslides, with operating and standby aeration blowers and routing valves supplies air to the silos, distribution bin, airslides, and de-aeration bins.

Dry sorbent is discharged out of the silo through a distribution bin and airslides into two de-aeration bins. The de-aeration bins are periodically filled and serve to control the fluidity of the material and minimize the head pressure that the material imposes on the downstream variable speed rotary feeders.

The feed stack-up below each de-aeration bin consists of a variable speed rotary feeder, vent hopper, fixed-speed rotary airlock, and material pick-up tee. There are two such stack-ups (one in-service and one stand-by), each with the capability to feed the primary conveying line. A pneumatically operated isolation valve is included at the discharge of the silo bin.

The dry sorbent is fed through a piping system (conveying lines) to injection lances located in the duct downstream of the air preheaters. Conveying air is supplied by three blower skid packages (two operating and one as standby) isolated by air-operated valves. Dry, high-pressure air is supplied for purging the bearings on the rotary feeders and airlocks and for pulsation cleaning of the bags in the bin vent filter at the top of each silo.

Because the dry sorbent handling system is a totally enclosed system using pressurized air as the carrying medium, particulate emissions are eliminated with the exception of those that are emitted as a result of truck traffic and from the baghouses installed on the storage silos. On a short-term basis, truck deliveries of dry sorbent are expected to be up to 2 per hour. At full load conditions, approximately 1550 tons of dry sorbent are potentially required per week. This equates to approximately 3215 trucks per year assuming a 100% capacity factor.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Magnesium Hydroxide Handling System

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:** Full enclosures
Emission Group 9S	Magnesium Hydroxide Handling Systems	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The magnesium hydroxide handling systems consists of truck unloading equipment, mag. hydroxide mix tanks, etc. See attached description of the magnesium hydroxide handling system.

Manufacturer:	**Model number:**	**Serial number:**
Various	Custom	N/A

Construction date:	**Installation date:**	**Modification date(s):**
MM/DD/YYYY	See equipment list in Attachment D	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 1,000 gallon mag. hydroxide mix tanks (2)

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
8000 gal/hr delivered	Mag. Hyd. 6,600,000 Gal./yr	8760 Hr/Yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes _X_ No

If yes, is it?

___ Indirect Fired ___Direct Fired

Maximum design heat input and/or maximum horsepower rating:
N/A

Type and Btu/hr rating of burners:

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.08	0.03
Particulate Matter (PM_{10})	0.51	0.21
Total Particulate Matter (TSP)	2.61	1.08
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory/permit limits and engineering knowledge. For purposes of determining potential fugitive emissions associated with this equipment, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Magnesium Hydroxide Handling System Description:

SO_3 Mitigation System:
The installation and operation of a Selective Catalytic Reduction (SCR) system in conjunction with a wet FGD system on a boiler combusting high sulfur coal can potentially lead to increased concentrations of SO_3. Subsequently, the SO_3 reacts with moisture in the stack plume and the atmosphere to support the secondary formation of H_2SO_4. If not mitigated, the increase in SO_3 and subsequent increase in the formation of H_2SO_4 can impact the visible appearance of the discharge plume downwind of the stack.

The Mitchell Plant SCR installation will utilize a low conversion catalyst that will help to minimize the conversion of SO_2 to SO_3 by the SCR system. Nevertheless, it is anticipated that a supplemental SO_3 mitigation system will be needed to help reduce SO_3 concentrations. Based on AEP's evaluation of various SO_3 mitigation systems at other AEP generating facilities, it has been determined that the primary SO_3 mitigation system that will be constructed at Mitchell plant will be a dry sorbent injection system. Hydrated Lime is the primarily used dry sorbent, with Trona being the secondary option. When Hydrated Lime is used, the dry sorbent injection system is supplemented with the injection of liquid Magnesium Hydroxide. For the purposes of this permit application, each of the options is described.

Magnesium Hydroxide Injection:
The purpose of magnesium hydroxide injection is to assist in the mitigation of SO_3 in the furnace in the event that Trona dry sorbent injection in not being used. If hydrated lime dry sorbent is injected into the flue gas downstream of the air preheater, magnesium hydroxide injection into the furnace will likely be needed to assist in the mitigation of SO_3. Magnesium hydroxide, if use, will be injected into the furnace as a 15% magnesium hydroxide/water slurry. Approximately 1.5 tons per hour (per unit) of magnesium hydroxide will be required for 90% SO_3 mitigation.

The magnesium hydroxide will be delivered to the Mitchell Plant site by tanker truck in a 60% magnesium hydroxide/water slurry and pumped into one of two storage tanks. The 60% solution is then pumped into a small mixing tank where it will be diluted with filtered water to a 15% slurry. The 15% slurry is then pumped to the furnaces and injected. The tanker trucks are expected to have a nominal capacity of approximately 4000 gallons. The only emissions associated with this material handling system will be fugitive particulate emissions associated with the delivery truck traffic on the plant site. On a short-term basis, tanker truck deliveries for the magnesium hydroxide system are expected to be up to 2 per hour.

At full load conditions, approximately 18,000 gallons of 60% slurry will be required per day. This equates to approximately 1650 truckloads of liquid magnesium hydroxide per year assuming a 100% capacity factor.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Urea Handling System

Emission unit ID number:	Emission unit name:	List any control devices associated with this emission unit:
N/A	Urea Handling Systems	Full and partial enclosures.

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The urea handling systems consists of truck unloading equipment, screw conveyor, mix tanks, etc. See attached description of the urea handling system.

Manufacturer:	Model number:	Serial number:
Various	Custom	N/A

Construction date:	Installation date:	Modification date(s):
MM/DD/YYYY	See equipment list in Attachment D	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 48 Ton Unloading Hopper, 200,000 gal. Urea Storage Tank.

Maximum Hourly Throughput:	Maximum Annual Throughput:	Maximum Operating Schedule:
Nominal 50 ton/hr	Dry urea 26,000 TPY Nominal,	8760 Hr/Yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes _X_ No

If yes, is it?

___ Indirect Fired ___Direct Fired

Maximum design heat input and/or maximum horsepower rating:
N/A

Type and Btu/hr rating of burners:

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.036	0.009
Particulate Matter (PM_{10})	2.47	0.64
Total Particulate Matter (TSP)	6.93	1.8
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory/permit limits and engineering knowledge.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

X.0. Source-Specific Requirements [Urea Handling (*Emission points listed in section 1.0. Table*)]
X.1. Limitations and Standards

The Urea handling system is subject to 45CSR§2-5 as outlined in the facility wide section of this permit (condition 3.1.9) regarding fugitive dust control system.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

X.2. Monitoring, Recordkeeping, and Reporting Requirements

See Permit conditions 3.4 and 3.5 in the facility wide section of this permit. [45 CSR 30-5.1.c]

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Dry Sorbent and Magnesium Hydroxide Handling System Description:

Urea Handling System:
Ammonia is the reagent used in the SCR process to reduce the NO_x, produced in the combustion process to elemental nitrogen and water vapor. The ammonia is generated from the Urea to Ammonia (U2A^{TM}) system. The U2A^{TM} system uses dry urea as the feedstock to produce ammonia vapor by hydrolyzing a urea solution to form ammonia vapor, carbon dioxide and water vapor. The urea solution is prepared from dry urea and steam condensate water.

The dry urea unloading system includes the equipment necessary to unload dry urea from trucks and transport it to urea solution mix tank. There is a provision to receive two 25-ton truckloads of dry urea back to back in a hopper located in a pit constructed by AEP at the Truck Unloading Station. Dry urea is then transferred from the hopper to a urea solution mix tank via full enclosed screw/drag conveyor equipment. In the mix tank, urea and condensate water is added in sufficient quantities to convert the dry urea into a 40% (by weight) urea solution for use in the urea to ammonia conversion process. The design is suitable for either prill or granular urea. The urea solution is transferred from the mix tank to a urea solution storage tank for use by the U2A^{TM} system.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Diesel Engine Driven Coping Power Emergency Generators (EG-1 and EG-2)

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
EG-1 EG-2	Diesel Driven Coping Power Emergency Generators EG-1 and EG-2	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
These are large diesel driven emergency generators. One rated at 3,717 bhp (EG-1) and one rated at 3,0004 bhp (EG-2). The generators are intended to provide facility auxiliary power in the event of a regional power grid outage.

Manufacturer:	**Model number:**	**Serial number:**
Caterpillar	C175-16 (EG-1); 3516C-HD TA (EG-2)	
Construction date:	**Installation date:**	**Modification date(s):**
08/2014	08/2014	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 3,717 bhp (EG-1) and 3,0004 bhp (EG-2)

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? _X_Yes ___ No	**If yes, is it? RICE** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 3,717 bhp (EG-1) at 1800rpm 3,0004 bhp (EG-2) at 1800rpm	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Diesel Fuel

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15ppm		

Emissions Data					
Criteria Pollutants	Potential Emissions				
	PPH		TPY		
	EG-1	EG-2	EG-1	EG-2	
Carbon Monoxide (CO)	7.66	4.85	1.92	1.21	
Nitrogen Oxides (NO_X)	59.9	36.4	14.98	9.1	
Lead (Pb)					
Particulate Matter ($PM_{2.5}$)	0.05	0.04	0.01	0.01	
Particulate Matter (PM_{10})	0.35	0.26	0.09	0.06	
Total Particulate Matter (TSP)	0.44	0.33	0.11	0.08	
Sulfur Dioxide (SO_2)	0.01	0.01	0.06	0.05	
Volatile Organic Compounds (VOC)	0.94	1.18	0.24	0.3	
Hazardous Air Pollutants	Potential Emissions				
	PPH		TPY		
Regulated Pollutants other than Criteria and HAP	Potential Emissions				
	PPH		TPY		
CO2	3961	3185	990.3	796.3	

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer’s Data used for NOx, CO, VOC, PM10 and CO2. AP-42 used for SO2

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 8.0 through 8.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 8.2 through 8.5 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? _X_Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	Emission unit name:	List any control devices associated with this emission unit:
17S	Unit 1 Emergency Diesel Driven Fire Pump	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Emergency diesel driven fire pump that replaced existing unit associated with Unit 1 at the plant. 249 BHP diesel engine.

Manufacturer:	Model number:	Serial number:
Cummins	CFP7E-F60 Fire Pump / QSB6.7 Engine	

Construction date: MM/DD/YYYY	Installation date: MM/DD/YYYY	Modification date(s): MM/DD/YYYY
08/2023	08/2023	08/2023

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Approx. 14 gal/hr, 249 BHP

Maximum Hourly Throughput:	Maximum Annual Throughput:	Maximum Operating Schedule:
Approx. 14 gal/hr	7,000 gal/yr	Assumed 500 hr/yr, but not limited during emergency

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No

If yes, is it? ☐ Indirect Fired ☑ Direct Fired

Maximum design heat input and/or maximum horsepower rating:

249 BHP

Type and Btu/hr rating of burners:

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15 ppm sulfur.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		Approx. 137,030 btu/gal

Emissions Data

Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.65	0.16
Nitrogen Oxides (NO_X)	1.36	0.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.06	0.015
Particulate Matter (PM_{10})	0.06	0.015
Total Particulate Matter (TSP)	0.06	0.015
Sulfur Dioxide (SO_2)	0.51	0.128
Volatile Organic Compounds (VOC)	0.63	0.16
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY
CO2	286.35	71.59

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, PM, and CO. AP-42 used for SO2, CO2, and VOC.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L.

Requirements currently captured in Title V permit:
R30-05100005-2019 (MM01) Section 7.1.

☐ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L.

Requirements currently captured in Title V permit:
R30-05100005-2019 (MM01) Sections 7.2 through 7.5.

Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	Emission unit name:	List any control devices associated with this emission unit:
18S	Unit 2 Emergency Diesel Driven Fire Pump	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Emergency diesel driven fire pump that will replace existing unit associated with Unit 2 at the plant. 249 BHP diesel engine.

Manufacturer:	Model number:	Serial number:
Cummins	CFP7E-F60 Fire Pump / QSB6.7 Engine	
Construction date: MM/DD/YYYY 06/2024	**Installation date:** MM/DD/YYYY 06/2024	**Modification date(s):** MM/DD/YYYY 06/2024

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Approx. 14 gal/hr, 249 BHP

Maximum Hourly Throughput:	Maximum Annual Throughput:	Maximum Operating Schedule:
Approx. 14 gal/hr	7,000 gal/yr	Assumed 500 hr/yr, but not limited during emergency

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No

If yes, is it? ☐ Indirect Fired ☑ Direct Fired

Maximum design heat input and/or maximum horsepower rating:	Type and Btu/hr rating of burners:
249 BHP	

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15 ppm sulfur.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		Approx. 137,030 btu/gal

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Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.65	0.16
Nitrogen Oxides (NO_X)	1.36	0.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.06	0.015
Particulate Matter (PM_{10})	0.06	0.015
Total Particulate Matter (TSP)	0.06	0.015
Sulfur Dioxide (SO_2)	0.51	0.128
Volatile Organic Compounds (VOC)	0.63	0.16
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY
CO2	286.35	71.59

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, PM, and CO. AP-42 used for SO2, CO2, and VOC.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.
This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Section 7.1.
☐ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)
This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Sections 7.2 through 7.5.
Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description		
Emission unit ID number: LF DEG	**Emission unit name:** LF DEG	**List any control devices associated with this emission unit:** N/A
Provide a description of the emission unit (type, method of operation, design parameters, etc.): Landfill Leachate Collection Sump Diesel Emergency Generator with integral 600 gallon diesel fuel tank. 300kw generator, 464 Bhp diesel engine.		
Manufacturer: Cummins	**Model number:** C300DQDAC gen/QSL9-G7 engine	**Serial number:**
Construction date: (MM/DD/YYYY) 04 / / 2020	**Installation date:** (MM/DD/YYYY) 04 / / 2020	**Modification date(s):** (MM/DD/YYYY) / / ; / / / / ; / /
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): approx. 23.1 gal/hr, 464 Bhp, 600 gal associated fuel tank.		
Maximum Hourly Throughput: approx 23.1 gal/hr	**Maximum Annual Throughput:** 11,550 gal/yr	**Maximum Operating Schedule:** assumed 500 hr/yr,but not limited during emergency
Fuel Usage Data **(fill out all applicable fields)**		
Does this emission unit combust fuel? ✔ Yes ___ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 464 Bhp		**Type and Btu/hr rating of burners:**
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. Diesel Fuel, less than15ppm S.		

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		approx. 137,030 btu/gal

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Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.31	0.08
Nitrogen Oxides (NO_X)	5.37	1.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.03	0.008
Particulate Matter (PM_{10})	0.03	0.008
Total Particulate Matter (TSP)	0.03	0.008
Sulfur Dioxide (SO_2)	0.11	0.028
Volatile Organic Compounds (VOC)	1.17	0.292
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, CO, SO2, and PM. AP-42 used for VOC.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. Requirements currently captured in Title V Permit: R30-05100005-2019 (MM01) Section 8.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
___Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) Requirements currently captured in Title V Permit: R30-05100005-2019 (MM01) Sections 8.2 through 8.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? _✔_Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
LF DEG2	LF DEG2	n/a

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Diesel driven 400kw, 513 Bhp, mobile emergency generator to be used at the Landfill Leachate Storage Pond

Manufacturer:	**Model number:**	**Serial number:**
Cummins	QSG12	

Construction date: MM/DD/YYYY	**Installation date:** MM/DD/YYYY	**Modification date(s):** MM/DD/YYYY
07/2023	07/2023	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

approx 23.2 gal/hr, 513 Bhp, 470 gallon fuel tank

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
approx 23.2 gal/hr	11,600 gal/yr	assumed 500hr/yr but not limited during emergency

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No

If yes, is it? ☐ Indirect Fired ☐ Direct Fired

Maximum design heat input and/or maximum horsepower rating:	**Type and Btu/hr rating of burners:**
513 Bhp	

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15ppm S.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		approx 137,030 btu/gal

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Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.08	0.02
Nitrogen Oxides (NO_X)	0.14	0.04
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.01	0.002
Particulate Matter (PM_{10})	0.01	0.002
Total Particulate Matter (TSP)	0.01	0.002
Sulfur Dioxide (SO_2)	0.11	0.026
Volatile Organic Compounds (VOC)	1.29	0.322
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, CO, and PM. AP-42 used for SO2 and VOC.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Section 8.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
☐ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Sections 8.2 through 8.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Attachment G

Air Pollution Control Device Forms

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML1 ESP	**List all emission units associated with this control device.** Unit 1	
Manufacturer: Wheelabrator Frye	**Model number:** 1487	**Installation date:** 12/30/1977

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare ___ Other (describe) ________________

___ Wet Plate Electrostatic Precipitator _X_ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
PM	100%	99.85%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Avg. Pressure Drop = 0.07 inches H_2O, Avg. Gas Flow Rate = $3,000 \times 10^3$ acfm, Avg. Operating temp. = 370 ^oF, Design Removal Efficiency = 99.85%

Is this device subject to the CAM requirements of 40 C.F.R. 64? _X_ Yes __ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitor opacity as an indicator of electrostatic precipitator performance. Periodic stack tests are performed to assure compliance with the particulate mass emissions standard.

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML1 FGD	**List all emission units associated with this control device.** Unit 1	
Manufacturer: B&W	**Model number:** Custom	**Installation date:** 04/28/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) _X_ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare ___ Other (describe) ________________

___ Wet Plate Electrostatic Precipitator ___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
SO_2	100%	95%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Full Load Flow Rate = 2.6×10^6 acfm, Outlet temperature = 128 ºF, Design Removal Efficiency = 95%

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of SO_2 emissions using CEMS

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML1 SCR	**List all emission units associated with this control device.** Unit 1	
Manufacturer:	**Model number:** Custom	**Installation date:** 05/02/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare __X Other (describe) Selective Catalytic Reduction

___ Wet Plate Electrostatic Precipitator ___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
NO_x	100%	90%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).
NOx Control Efficiency = 90.0%, Design Temperature = 750 ºF, Maximum ammonia slip = 2 ppmvd at 3% O_2

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of NO_x emissions using CEMS

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML2 ESP	**List all emission units associated with this control device.** Unit 2	
Manufacturer: Wheelabrator Frye	**Model number:** 1487	**Installation date:** 06/16/1978

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare ___ Other (describe) ________________

___ Wet Plate Electrostatic Precipitator _X_ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
PM	100%	99.85%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Avg. Pressure Drop = 0.07 inches H_2O, Avg. Gas Flow Rate = $3{,}000 \times 10^3$ acfm, Avg. Operating temp. = 370 ºF, Design Removal Efficiency = 99.85%

Is this device subject to the CAM requirements of 40 C.F.R. 64? _X_ Yes __ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitor opacity as an indicator of electrostatic precipitator performance. Periodic stack tests are performed to assure compliance with the particulate mass emissions standard.

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:
ML2 FGD

List all emission units associated with this control device.
Unit 2

Manufacturer:
B&W

Model number:
Custom

Installation date:
01/15/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) _X_ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare ___ Other (describe) _____________

___ Wet Plate Electrostatic Precipitator ___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
SO_2	100%	95%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Full Load Flow Rate = $2.6x10^6$ acfm, Outlet temperature = 128 ºF, Design Removal Efficiency = 95%

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of SO_2 emissions using CEMS

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML2 SCR	**List all emission units associated with this control device.** Unit 2	
Manufacturer:	**Model number:** Custom	**Installation date:** 05/02/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare _X_ Other (describe) Selective Catalytic Reduction

___ Wet Plate Electrostatic Precipitator ___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
NO_x	100%	90%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).
NOx Control Efficiency = 90.0%, Design Temperature = 750 ºF, Maximum ammonia slip = 2 ppmvd at 3% O_2

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of NO_x emissions using CEMS

Attachment H

Compliance Assurance Monitoring (CAM) Forms

ATTACHMENT H - Compliance Assurance Monitoring (CAM) Plan Form

For definitions and information about the CAM rule, please refer to 40 CFR Part 64. Additional information (including guidance documents) may also be found at http://www.epa.gov/ttn/emc/cam.html

CAM APPLICABILITY DETERMINATION

1) Does the facility have a PSEU (Pollutant-Specific Emissions Unit considered separately with respect to **EACH** regulated air pollutant) that is subject to CAM (40 CFR Part 64), which must be addressed in this CAM plan submittal? To determine applicability, a PSEU must meet **all** of the following criteria (*If No, then the remainder of this form need not be completed*):

☒ YES ☐ NO

a. The PSEU is located at a major source that is required to obtain a Title V permit;

b. The PSEU is subject to an emission limitation or standard for the applicable regulated air pollutant that is NOT exempt;

LIST OF EXEMPT EMISSION LIMITATIONS OR STANDARDS:

- NSPS (40 CFR Part 60) or NESHAP (40 CFR Parts 61 and 63) proposed after 11/15/1990.
- Stratospheric Ozone Protection Requirements.
- Acid Rain Program Requirements.
- Emission Limitations or Standards for which a WVDEP Division of Air Quality Title V permit specifies a continuous compliance determination method, as defined in 40 CFR §64.1.
- An emission cap that meets the requirements specified in 40 CFR §70.4(b)(12).

c. The PSEU uses an add-on control device (as defined in 40 CFR §64.1) to achieve compliance with an emission limitation or standard;

d. The PSEU has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than the Title V Major Source Threshold Levels; AND

e. The PSEU is NOT an exempt backup utility power emissions unit that is municipally-owned.

BASIS OF CAM SUBMITTAL

2) Mark the appropriate box below as to why this CAM plan is being submitted as part of an application for a Title V permit:

☒ RENEWAL APPLICATION. **ALL** PSEUs for which a CAM plan has NOT yet been approved need to be addressed in this CAM plan submittal.

☐ INITIAL APPLICATION (submitted after 4/20/98). **ONLY** large PSEUs (i. e., PSEUs with potential post-control device emissions of an applicable regulated air pollutant that are equal to or greater than Major Source Threshold Levels) need to be addressed in this CAM plan submittal.

☐ SIGNIFICANT MODIFICATION TO LARGE PSEUs. **ONLY** large PSEUs being modified after 4/20/98 need to be addressed in this cam plan submittal. For large PSEUs with an approved CAM plan, Only address the appropriate monitoring requirements affected by the significant modification.

3) [a] BACKGROUND DATA AND INFORMATION					
Complete the following table for **all** PSEUs that need to be addressed in this CAM plan submittal. This section is to be used to provide background data and information for each PSEU In order to supplement the submittal requirements specified in 40 CFR §64.4. If additional space is needed, attach and label accordingly.					
PSEU DESIGNATION	DESCRIPTION	POLLUTANT	CONTROL DEVICE	[b] EMISSION LIMITATION or STANDARD	[c] MONITORING REQUIREMENT
Unit 1	Coal-Fired Steam Generator	PM	ESP	45CSR2-4.1.a	Monitor Duct Opacity Using COMS
Unit 2	Coal-Fired Steam Generator	PM	ESP	45CSR2-4.1.a	Monitor Duct Opacity Using COMS
<u>EXAMPLE</u> Boiler No. 1	Wood-Fired Boiler	PM	Multiclone	45CSR§2-4.1.c.; 9.0 lb/hr	Monitor pressure drop across multiclone: Weekly inspection of multiclone

[a] If a control device is common to more than one PSEU, one monitoring plan may be submitted for the control device with the affected PSEUs identified and any conditions that must be maintained or monitored in accordance with 40 CFR §64.3(a). If a single PSEU is controlled by more than one control device similar in design and operation, one monitoring plan for the applicable control devices may be submitted with the applicable control devices identified and any conditions that must be maintained or monitored in accordance with 40 CFR §64.3(a).

[b] Indicate the emission limitation or standard for any applicable requirement that constitutes an emission limitation, emission standard, or standard of performance (as defined in 40 CFR §64.1).

[c] Indicate the monitoring requirements for the PSEU that are required by an applicable regulation or permit condition.

CAM MONITORING APPROACH CRITERIA			
Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide monitoring data and information for EACH indicator selected for EACH PSEU in order to meet the monitoring design criteria specified in 40 CFR §64.3 and §64.4. if more than two indicators are being selected for a PSEU or if additional space is needed, attach and label accordingly with the appropriate PSEU designation, pollutant, and indicator numbers.			
4a) PSEU Designation: Unit 1	**4b) Pollutant:** PM	**4c) [a] Indicator No. 1:** Opacity	**4d) [a] Indicator No. 2:** Opacity
5a) GENERAL CRITERIA Describe the MONITORING APPROACH used to measure the indicators:		Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.	Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.
[b] Establish the appropriate INDICATOR RANGE or the procedures for establishing the indicator range which provides a reasonable assurance of compliance:		Opacity data has been collected during Method 5 particulate emission testing. The plan will incorporate existing test data along with CAM stack testing to verify a conservative indicator range. The proposed upper threshold value of the indicator range is a 3-hour block average opacity value greater than 10% Opacity	Excess short duration opacity increases occurring during any calendar quarter are not to exceed 5% of the total operating time.
5b) PERFORMANCE CRITERIA Provide the SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, such as detector location, installation specifications, and minimum acceptable accuracy:		The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.	The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.
[c] For new or modified monitoring equipment, provide VERIFICATION PROCEDURES, including manufacturer's recommendations, TO CONFIRM THE OPERATIONAL STATUS of the monitoring:		N/A	N/A
Provide QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES that are adequate to ensure the continuing validity of the data, (i.e., daily calibrations, visual inspections, routine maintenance, RATA, etc.):		QA/QC is performed in accordance with 40 CFR 75.	QA/QC is performed in accordance with 40 CFR 75.
[d] Provide the MONITORING FREQUENCY:		Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)	Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)
Provide the DATA COLLECTION PROCEDURES that will be used:		Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.	Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.
Provide the DATA AVERAGING PERIOD for the purpose of determining whether an excursion or exceedance has occurred:		The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase).	The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase) and the total operating time of the units.

[a] Describe all indicators to be monitored which satisfies 40 CFR §64.3(a). Indicators of emission control performance for the control device and associated capture system may include measured or predicted emissions (including visible emissions or opacity), process and control device operating parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities.

[b] Indicator Ranges may be based on a single maximum or minimum value or at multiple levels that are relevant to distinctly different operating conditions, expressed as a function of process variables, expressed as maintaining the applicable indicator in a particular operational status or designated condition, or established as interdependent between more than one indicator. For CEMS, COMS, or PEMS, include the most recent certification test for the monitor.

[c] The verification for operational status should include procedures for installation, calibration, and operation of the monitoring equipment, conducted in accordance with the manufacturer's recommendations, necessary to confirm the monitoring equipment is operational prior to the commencement of the required monitoring.

[d] Emission units with post-control PTE ≥ 100 percent of the amount classifying the source as a major source (i.e., Large PSEU) must collect four or more values per hour to be averaged. A reduced data collection frequency may be approved in limited circumstances. Other emission units must collect data at least once per 24 hour period.

CAM MONITORING APPROACH CRITERIA

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide monitoring data and information for EACH indicator selected for EACH PSEU in order to meet the monitoring design criteria specified in 40 CFR §64.3 and §64.4. if more than two indicators are being selected for a PSEU or if additional space is needed, attach and label accordingly with the appropriate PSEU designation, pollutant, and indicator numbers.

4a) PSEU Designation: Unit 2	**4b) Pollutant:** PM	**4c) [a] Indicator No. 1:** Opacity	**4d) [a] Indicator No. 2:** Opacity
5a) GENERAL CRITERIA Describe the MONITORING APPROACH used to measure the indicators:		Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.	Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.
[b] Establish the appropriate INDICATOR RANGE or the procedures for establishing the indicator range which provides a reasonable assurance of compliance:		Opacity data has been collected during Method 5 particulate emission testing. The plan will incorporate existing test data along with CAM stack testing to verify a conservative indicator range. The proposed upper threshold value of the indicator range is a 3-hour block average opacity value greater than 10% Opacity	Excess short duration opacity increases occurring during any calendar quarter are not to exceed 5% of the total operating time.
5b) PERFORMANCE CRITERIA Provide the SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, such as detector location, installation specifications, and minimum acceptable accuracy:		The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.	The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.
[c] For new or modified monitoring equipment, provide VERIFICATION PROCEDURES, including manufacturer's recommendations, TO CONFIRM THE OPERATIONAL STATUS of the monitoring:		N/A	N/A
Provide QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES that are adequate to ensure the continuing validity of the data, (i.e., daily calibrations, visual inspections, routine maintenance, RATA, etc.):		QA/QC is performed in accordance with 40 CFR 75.	QA/QC is performed in accordance with 40 CFR 75.
[d] Provide the MONITORING FREQUENCY:		Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)	Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)
Provide the DATA COLLECTION PROCEDURES that will be used:		Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.	Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.
Provide the DATA AVERAGING PERIOD for the purpose of determining whether an excursion or exceedance has occurred:		The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase).	The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase) and the total operating time of the units.

[a] Describe all indicators to be monitored which satisfies 40 CFR §64.3(a). Indicators of emission control performance for the control device and associated capture system may include measured or predicted emissions (including visible emissions or opacity), process and control device operating parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities.

[b] Indicator Ranges may be based on a single maximum or minimum value or at multiple levels that are relevant to distinctly different operating conditions, expressed as a function of process variables, expressed as maintaining the applicable indicator in a particular operational status or designated condition, or established as interdependent between more than one indicator. For CEMS, COMS, or PEMS, include the most recent certification test for the monitor.

[c] The verification for operational status should include procedures for installation, calibration, and operation of the monitoring equipment, conducted in accordance with the manufacturer's recommendations, necessary to confirm the monitoring equipment is operational prior to the commencement of the required monitoring.

[d] Emission units with post-control PTE ≥ 100 percent of the amount classifying the source as a major source (i.e., Large PSEU) must collect four or more values per hour to be averaged. A reduced data collection frequency may be approved in limited circumstances. Other emission units must collect data at least once per 24 hour period.

RATIONALE AND JUSTIFICATION

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide rationale and justification for the selection of EACH indicator and monitoring approach and EACH indicator range in order to meet the submittal requirements specified in 40 CFR §64.4.

6a) PSEU Designation:	6b) Regulated Air Pollutant:
Unit 1	PM

7) **INDICATORS AND THE MONITORING APPROACH**: Provide the rationale and justification for the selection of the indicators and the monitoring approach used to measure the indicators. Also provide any data supporting the rationale and justification. Explain the reasons for any differences between the verification of operational status or the quality assurance and control practices proposed, and the manufacturer's recommendations. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

Wheeling Power believes that the continuous opacity monitoring system (COMS) data is the most appropriate and readily available indicator for continuously evaluating the performance and operations of the electrostatic precipitator and thereby assessing compliance with the applicable particulate emission rate limitation between periodic 40 CFR Part 60, Method 5 compliance testing. Monitoring of other ESP operating parameters such as TR set voltage and current levels may be beneficial in evaluating ESP performance trends on a short term basis as well, however, these are not continuous nor are they direct indicators of conditions in the stack prior to release of the flue gas. For these reasons, a specific corrective action plan has been developed based upon opacity monitoring. This corrective action plan will be implemented at any time there is a short duration or a sustained duration increase in opacity above the upper threshold value of the indicator range.

Monitoring: The permittee shall monitor and maintain 6-minute opacity averages measured by a continuous opacity monitoring system, operated and maintained pursuant to 40 C.F.R. Part 75, including the minimum data requirements, in order to determine 3-hour block average opacity values. The 6-minute opacity averages shall be used to calculate 3-hour block average opacity values. The COM QA/QC procedures shall be equivalent to the applicable requirements of 40 C.F.R. Part 75. Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, but not limited to, calibration checks and required zero and span adjustments), the opacity shall be continuously monitored (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs and QA/QC activities shall not be used for purposes of 40 C.F.R. Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement. Data availability shall be at least of 50% of the operating time in the 3-hour block to satisfy the data requirements to calculate the 3-hour average opacity. The number of invalid 3-hour blocks shall not exceed 15% of the total 3-hour blocks during unit operation for a quarterly reporting period.

Recordkeeping: Records of the block 3-hour COMS opacity averages and corrective actions taken during excursions of the CAM plan indicator range shall be maintained on site and shall be made available to the Director or his duly authorized representative upon request. COMS performance data will be maintained in accordance with 40 C.F.R. Part 75 recordkeeping requirements. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 C.F.R. §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 C.F.R. Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

Reporting: The permittee shall submit semiannual monitoring reports to the DAQ. A report for monitoring under 40 C.F.R. 64 shall include, at a minimum, the following information: (a) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions and the corrective actions taken; (b) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks); and (c) A description of the actions taken to implement a quality improvement plan (QIP) during the reporting period as specified in 40 C.F.R. §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

For purposes of this corrective action plan:
A **short duration increase in opacity** is defined as an increase in opacity that persists for at least a block three-hour period (30 consecutive 6-minute periods), and which measure greater than the upper threshold value of the indicator range.
A **sustained increase in opacity (or an excursion)** is defined as an increase in opacity that persists for two consecutive 3-hour block periods (two consecutive short duration opacity increase periods), and which measure greater than the upper threshold value of the indicator range.

This plan outlines specific corrective action procedures to be implemented by plant personnel for the following scenarios:

Case A: Upon alarm of a Short duration increase in opacity.
Case B: Upon alarm of a sustained increase in opacity.

These corrective action procedures do not apply to opacity increases that occur during exempt periods. Assignment of personnel to carry out each step of this plan will be the sole responsibility of Plant Management and may change based upon specific conditions.

Case A: (Short duration increase in opacity.)
Plant personnel will continue to observe the COMS data and at the same time initiate a review of other available information (such as: TR set status, voltage, current, operating parameters, etc.) in order to validate and/or identify the cause of the opacity increase.

1. If the opacity does not return to and remain at normal operating levels within (within 180 minutes), further corrective action may become necessary.
1. If the cause of the opacity increase is not already known, unit-operating data will be collected for the purpose of determining the cause of the opacity increase.
1. If the opacity increase occurs after normal working hours, on weekends, or holidays; the unit-operations data may be collected the following working day.
1. Once the cause of the opacity increase is determined, plant personnel will take necessary steps to mitigate the unit operating condition or equipment failure that is found to be causing the short duration opacity increase.

B. Case B: (Sustained increase in opacity.)

1. Upon detecting an excursion or exceedance, the permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.
2. If the opacity does not return and remain at normal operating levels within a short duration (within 180 minutes), and the cause of the opacity increase is not already known, further analysis of the unit, and auxiliary operating data will be analyzed and recorded for the purpose of determining the cause of the opacity increase.
3. If the opacity increase occurs after normal working hours, on weekends, or holidays, off-shift personnel may be required to determine the cause of the opacity increase and initiate appropriate corrective actions.
4. Plant personnel will initiate the following corrective actions as necessary to reduce stack opacity to normal operating levels:
   a. Any individual TR sets that are out-of-service or not operating at normal power levels shall be repaired and/or adjusted as appropriate.
   b. ESP rapping procedures may be initiated and/or adjusted as necessary.
   c. Flue gas conditioning systems will be placed in service or adjusted as necessary.
   d. Depending on the specific events found to be the cause of the opacity increase, other corrective actions will be implemented as necessary to reduce the opacity to normal operating levels.

If five (5) percent or greater of the block three (3) hour average COMS opacity values indicate excursions of the 10% opacity threshold during a calendar quarter, the permittee shall develop and implement a QIP. The Director may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to permit condition 3.3.1.

If the opacity level continues to exceed the upper threshold value of the indicator range Opacity after the corrective actions as outlined above for Case B are implemented, plant personnel will contact appropriate management staff to obtain necessary approvals to reduce load, or in extreme cases, commence a unit shutdown in order to remediate the cause of the opacity increase.

Based on the results of a determination of actions taken by the permittee, the Administrator or the Director may require the permittee to develop and implement a QIP. If a QIP is required, then it shall be developed, implemented, and modified as required according to 40 C.F.R. §§ 64.8(b) through (e).

8) **INDICATOR RANGES**: Provide the rationale and justification for the selection of the indicator ranges. The rationale and justification shall indicate how **EACH** indicator range was selected by either a COMPLIANCE OR PERFORMANCE TEST, a TEST PLAN AND SCHEDULE, or by ENGINEERING ASSESSMENTS. Depending on which method is being used for each indicator range, include the specific information required below for that specific indicator range. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- COMPLIANCE OR PERFORMANCE TEST (Indicator ranges determined from control device operating parameter data obtained during a compliance or performance test conducted under regulatory specified conditions or under conditions representative of maximum potential emissions under anticipated operating conditions. Such data may be supplemented by engineering assessments and manufacturer's recommendations). The rationale and justification shall INCLUDE a summary of the compliance or performance test results that were used to determine the indicator range, and documentation indicating that no changes have taken place that could result in a significant change in the control system performance or the selected indicator ranges since the compliance or performance test was conducted.

- TEST PLAN AND SCHEDULE (Indicator ranges will be determined from a proposed implementation plan and schedule for installing, testing, and performing any other appropriate activities prior to use of the monitoring). The rationale and justification shall INCLUDE the proposed implementation plan and schedule that will provide for use of the monitoring as expeditiously as practicable after approval of this CAM plan, except that in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval.

- ENGINEERING ASSESSMENTS (Indicator Ranges or the procedures for establishing indicator ranges are determined from engineering assessments and other data, such as manufacturers' design criteria and historical monitoring data, because factors specific to the type of monitoring, control device, or PSEU make compliance or performance testing unnecessary). The rationale and justification shall INCLUDE documentation demonstrating that compliance testing is not required to establish the indicator range.

RATIONALE AND JUSTIFICATION:

The indicator is based upon an opacity/mass relationship of the emissions unit at full load operation. It is anticipated that the 0.05 lb/mmBTU particulate emissions limit will not be exceeded when 3-hour block opacity values remain at or below 10% opacity. Accordingly, the Mitchell Plant can demonstrate a reasonable assurance of compliance with the particulate mass emission limit as long as the 3-hour block average stack (duct) opacity is maintained below the upper threshold value of 10%. opacity.

Wheeling Power Company is proposing that the opacity/mass relationship be verified using existing baseline mass particulate emission test results and additional full load “CAM Testing”. Based on previous compliance or performance testing of the electrostatic precipitator using 40 CFR Part 60 methods, Wheeling Power Company believes that compliance with the upper threshold value of 10% opacity for the 3-hour block average periods will provide reasonable assurance of compliance with the particulate emission standard. The 10% threshold was chosen for two reasons: first, the historic particulate emission test data that has been collected over the past few years shows this source to be in compliance with the 0.05 lb/mmBTU particulate limit by a good margin when stack opacity is less than 10% and second, we presume that DAQ established the 10% 45 CSR 2 opacity SIP limit at a level that DAQ believes sources will likely be in compliance with the mass SIP limit to provide a conservative reasonable assurance of compliance with the mass emission limit. The 3-hour block averaging time period was chosen to provide adequate time to make operational corrections to comply with the particulate mass emission standard.

Historic baseline test data collected in the past recent years and submitted to WV DEP is summarized below:

Test Date	Measured Emission Rate	Average Opacity
8/21/2000	0.0180 lb/mmBtu	7.0
8/5/2003	0.0147 lb/mmBtu	3.3
7/14/2006	0.0134 lb/mmBtu	3.2
4/7/2009	0.0195 lb/mmBtu	5.1
1/24/2012	0.0337 lb/mmBtu	3.7
12/14/2012	0.0037 lb/mmBtu	6.1
3/18/2014	0.0033 lb/mmBtu	7.6
3/3/2016	0.0030 lb/mmBtu	3.9
12/12/2018	0.0026 lb/mmBtu	6.2
6/17/2021	0.0040 lb/mmBtu	6.8

No changes have been made that would significantly impact ESP performance. Data collected during future periodic 45CSR2 mass emissions tests will be used to supplement the existing data set in order to verify the continuing appropriateness of the 10% indicator range value.

While the above compliance test data has been used as baseline confirmation of mass emission compliance at full load, additional full load testing was also conducted to supplement the data set with data points collected while operating at or near the 10% opacity threshold. These points were established by “de-tuning” the electrostatic precipitator (making adjustments to operating parameters of the precipitator) and/or making other operational adjustments to the unit to increase the particulate mass loading and opacity downstream of the precipitator. The data set used to establish the opacity/mass relationship and the indicator verification consist of the particulate mass emissions compliance test data and the data collected during the CAM testing program. The CAM testing at elevated opacity levels was performed for one 2-hour test run (as opposed to a full 6-hour time period typical of a compliance test). Limiting the data collection to 2-hours minimized the environmental impacts of operating the particulate control equipment under less than normal operating conditions. Nevertheless, it was understood that more than one run under specific unit operating conditions may be necessary.

RATIONALE AND JUSTIFICATION	
Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide rationale and justification for the selection of EACH indicator and monitoring approach and EACH indicator range in order to meet the submittal requirements specified in 40 CFR §64.4.	
6a) PSEU Designation: Unit 2	6b) Regulated Air Pollutant: PM

7) **INDICATORS AND THE MONITORING APPROACH**: Provide the rationale and justification for the selection of the indicators and the monitoring approach used to measure the indicators. Also provide any data supporting the rationale and justification. Explain the reasons for any differences between the verification of operational status or the quality assurance and control practices proposed, and the manufacturer's recommendations. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

Wheeling Power believes that the continuous opacity monitoring system (COMS) data is the most appropriate and readily available indicator for continuously evaluating the performance and operations of the electrostatic precipitator and thereby assessing compliance with the applicable particulate emission rate limitation between periodic 40 CFR Part 60, Method 5 compliance testing. Monitoring of other ESP operating parameters such as TR set voltage and current levels may be beneficial in evaluating ESP performance trends on a short term basis as well, however, these are not continuous nor are they direct indicators of conditions in the stack prior to release of the flue gas. For these reasons, a specific corrective action plan has been developed based upon opacity monitoring. This corrective action plan will be implemented at any time there is a short duration or a sustained duration increase in opacity above the upper threshold value of the indicator range.

Monitoring: The permittee shall monitor and maintain 6-minute opacity averages measured by a continuous opacity monitoring system, operated and maintained pursuant to 40 C.F.R. Part 75, including the minimum data requirements, in order to determine 3-hour block average opacity values. The 6-minute opacity averages shall be used to calculate 3-hour block average opacity values. The COM QA/QC procedures shall be equivalent to the applicable requirements of 40 C.F.R. Part 75. Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, but not limited to, calibration checks and required zero and span adjustments), the opacity shall be continuously monitored (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs and QA/QC activities shall not be used for purposes of 40 C.F.R. Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement. Data availability shall be at least of 50% of the operating time in the 3-hour block to satisfy the data requirements to calculate the 3-hour average opacity. The number of invalid 3-hour blocks shall not exceed 15% of the total 3-hour blocks during unit operation for a quarterly reporting period.

Recordkeeping: Records of the block 3-hour COMS opacity averages and corrective actions taken during excursions of the CAM plan indicator range shall be maintained on site and shall be made available to the Director or his duly authorized representative upon request. COMS performance data will be maintained in accordance with 40 C.F.R. Part 75 recordkeeping requirements. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 C.F.R. §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 C.F.R. Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

Reporting: The permittee shall submit semiannual monitoring reports to the DAQ. A report for monitoring under 40 C.F.R. 64 shall include, at a minimum, the following information: (a) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions and the corrective actions taken; (b) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks); and (c) A description of the actions taken to implement a quality improvement plan (QIP) during the reporting period as specified in 40 C.F.R. §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

For purposes of this corrective action plan:
A **short duration increase in opacity** is defined as an increase in opacity that persists for at least a block three-hour period (30 consecutive 6-minute periods), and which measure greater than the upper threshold value of the indicator range.
A **sustained increase in opacity (or an excursion)** is defined as an increase in opacity that persists for two consecutive 3-hour block periods (two consecutive short duration opacity increase periods), and which measure greater than the upper threshold value of the indicator range.

This plan outlines specific corrective action procedures to be implemented by plant personnel for the following scenarios:

Case A: Upon alarm of a Short duration increase in opacity.
Case B: Upon alarm of a sustained increase in opacity.

These corrective action procedures do not apply to opacity increases that occur during exempt periods. Assignment of personnel to carry out each step of this plan will be the sole responsibility of Plant Management and may change based upon specific conditions.

Case A: (Short duration increase in opacity.)
Plant personnel will continue to observe the COMS data and at the same time initiate a review of other available information (such as: TR set status, voltage, current, operating parameters, etc.) in order to validate and/or identify the cause of the opacity increase.

1. If the opacity does not return to and remain at normal operating levels within (within 180 minutes), further corrective action may become necessary.
3. If the cause of the opacity increase is not already known, unit-operating data will be collected for the purpose of determining the cause of the opacity increase.
3. If the opacity increase occurs after normal working hours, on weekends, or holidays; the unit-operations data may be collected the following working day.
4. Once the cause of the opacity increase is determined, plant personnel will take necessary steps to mitigate the unit operating condition or equipment failure that is found to be causing the short duration opacity increase.

B. Case B: (Sustained increase in opacity.)
1. Upon detecting an excursion or exceedance, the permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.
2. If the opacity does not return and remain at normal operating levels within a short duration (within 180 minutes), and the cause of the opacity increase is not already known, further analysis of the unit, and auxiliary operating data will be analyzed and recorded for the purpose of determining the cause of the opacity increase.
3. If the opacity increase occurs after normal working hours, on weekends, or holidays, off-shift personnel may be required to determine the cause of the opacity increase and initiate appropriate corrective actions.
4. Plant personnel will initiate the following corrective actions as necessary to reduce stack opacity to normal operating levels:
    a. Any individual TR sets that are out-of-service or not operating at normal power levels shall be repaired and/or adjusted as appropriate.
    b. ESP rapping procedures may be initiated and/or adjusted as necessary.
    c. Flue gas conditioning systems will be placed in service or adjusted as necessary.
    d. Depending on the specific events found to be the cause of the opacity increase, other corrective actions will be implemented as necessary to reduce the opacity to normal operating levels.

If five (5) percent or greater of the block three (3) hour average COMS opacity values indicate excursions of the 10% opacity threshold during a calendar quarter, the permittee shall develop and implement a QIP. The Director may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to permit condition 3.3.1.

If the opacity level continues to exceed the upper threshold value of the indicator range Opacity after the corrective actions as outlined above for Case B are implemented, plant personnel will contact appropriate management staff to obtain necessary approvals to reduce load, or in extreme cases, commence a unit shutdown in order to remediate the cause of the opacity increase.

Based on the results of a determination of actions taken by the permittee, the Administrator or the Director may require the permittee to develop and implement a QIP. If a QIP is required, then it shall be developed, implemented, and modified as required according to 40 C.F.R. §§ 64.8(b) through (e).

8) **INDICATOR RANGES**: Provide the rationale and justification for the selection of the indicator ranges. The rationale and justification shall indicate how **EACH** indicator range was selected by either a COMPLIANCE OR PERFORMANCE TEST, a TEST PLAN AND SCHEDULE, or by ENGINEERING ASSESSMENTS. Depending on which method is being used for each indicator range, include the specific information required below for that specific indicator range. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- COMPLIANCE OR PERFORMANCE TEST (Indicator ranges determined from control device operating parameter data obtained during a compliance or performance test conducted under regulatory specified conditions or under conditions representative of maximum potential emissions under anticipated operating conditions. Such data may be supplemented by engineering assessments and manufacturer's recommendations). The rationale and justification shall INCLUDE a summary of the compliance or performance test results that were used to determine the indicator range, and documentation indicating that no changes have taken place that could result in a significant change in the control system performance or the selected indicator ranges since the compliance or performance test was conducted.

- TEST PLAN AND SCHEDULE (Indicator ranges will be determined from a proposed implementation plan and schedule for installing, testing, and performing any other appropriate activities prior to use of the monitoring). The rationale and justification shall INCLUDE the proposed implementation plan and schedule that will provide for use of the monitoring as expeditiously as practicable after approval of this CAM plan, except that in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval.

- ENGINEERING ASSESSMENTS (Indicator Ranges or the procedures for establishing indicator ranges are determined from engineering assessments and other data, such as manufacturers' design criteria and historical monitoring data, because factors specific to the type of monitoring, control device, or PSEU make compliance or performance testing unnecessary). The rationale and justification shall INCLUDE documentation demonstrating that compliance testing is not required to establish the indicator range.

RATIONALE AND JUSTIFICATION:

The indicator is based upon an opacity/mass relationship of the emissions unit at full load operation. It is anticipated that the 0.05 lb/mmBTU particulate emissions limit will not be exceeded when 3-hour block opacity values remain at or below 10% opacity. Accordingly, the Mitchell Plant can demonstrate a reasonable assurance of compliance with the particulate mass emission limit as long as the 3-hour block average stack (duct) opacity is maintained below the upper threshold value of 10%. opacity.

Wheeling Power Company is proposing that the opacity/mass relationship be verified using existing baseline mass particulate emission test results and additional full load "CAM Testing". Based on previous compliance or performance testing of the electrostatic precipitator using 40 CFR Part 60 methods, Wheeling Power Company believes that compliance with the upper threshold value of 10% opacity for the 3-hour block average periods will provide reasonable assurance of compliance with the particulate emission standard. The 10% threshold was chosen for two reasons: first, the historic particulate emission test data that has been collected over the past few years shows this source to be in compliance with the 0.05 lb/mmBTU particulate limit by a good margin when stack opacity is less than 10% and second, we presume that DAQ established the 10% 45 CSR 2 opacity SIP limit at a level that DAQ believes sources will likely be in compliance with the mass SIP limit to provide a conservative reasonable assurance of compliance with the mass emission limit. The 3-hour block averaging time period was chosen to provide adequate time to make operational corrections to comply with the particulate mass emission standard.

Historic baseline test data collected in the past recent years and submitted to WV DEP is summarized below:

Test Date	Measured Emission Rate	Average Opacity
8/21/2000	0.0180 lb/mmBtu	7.0
8/5/2003	0.0147 lb/mmBtu	3.3
7/14/2006	0.0134 lb/mmBtu	3.2
4/8/2009	0.0099 lb/mmBtu	5.9
1/26/2012	0.0421 lb/mmBtu	6.2
12/13/2012	0.0038 lb/mmBtu	6.1
3/20/2014	0.0035 lb/mmBtu	7.2
3/2/2016	0.0031 lb/mmBtu	5.9
12/13/2018	0.0045 lb/mmBtu	8.5
6/16/2021	0.0039 lb/mmBtu	8.7

No changes have been made that would significantly impact ESP performance. Data collected during future periodic 45CSR2 mass emissions tests will be used to supplement the existing data set in order to verify the continuing appropriateness of the 10% indicator range value.

While the above compliance test data has been used as baseline confirmation of mass emission compliance at full load, additional full load testing was also conducted to supplement the data set with data points collected while operating at or near the 10% opacity threshold. These points were established by "de-tuning" the electrostatic precipitator (making adjustments to operating parameters of the precipitator) and/or making other operational adjustments to the unit to increase the particulate mass loading and opacity downstream of the precipitator. The data set used to establish the opacity/mass relationship and the indicator verification consist of the particulate mass emissions compliance test data and the data collected during the CAM testing program. The CAM testing at elevated opacity levels was performed for one 2-hour test run (as opposed to a full 6-hour time period typical of a compliance test). Limiting the data collection to 2-hours minimized the environmental impacts of operating the particulate control equipment under less than normal operating conditions. Nevertheless, it was understood that more than one run under specific unit operating conditions may be necessary.

Attachment I
Existing Applicable Permits

West Virginia Department of Environmental Protection

Earl Ray Tomblin
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Class I Administrative Update Permit

R13-2608E

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:

AEP Generation Resources, Inc.
Mitchell Plant
051-00005

William F. Dunham
Deputy Director

Issued: May 12, 2014

This permit will supercede and replace Permit R13-2608D.

Facility Location:	State Route 2 Cresap/Moundsville, Marshall County, West Virginia
Mailing Address:	Mitchell Plant P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generating Plant
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Permit Type:	Administrative Update
Description of Change:	This update is to correctly codify the term of the limited use for Boiler Aux-1 in the terms as defined in the Subpart DDDDD of Part 63 of Chapter 40 and correctly define the compliance path for Aux-1 under Subpart Db of Part 60 in Chapter 40.

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	Design Capacity	Control Device
1S - Limestone Material Handling				
BUN-1		Limestone Unloading Crane	1,000 TPH	None
RH-1		Limestone Unloading Hopper	60 Tons	WS/PE
VF-1		Limestone Unloading Feeder	750 TPH	FE
BC-1		Limestone Dock/Connecting Conveyor	750 TPH	PE
TH-1		Limestone Transfer House #1	750 TPH	FE
BC-2		Limestone Storage Pile Stacking Conveyor	750 TPH	PE
LSSP		Limestone Active/Long-Term Stockpile	41,300 Tons	None
2S - Gypsum Material Handling				
BC-8		Vacuum Collecting Conveyor	200 TPH	PE
TH-3		Gypsum Transfer House #3	200 TPH	FE
BC-9		Connecting Conveyor	200 TPH	PE
TH-4		Gypsum Transfer House #4	200 TPH	FE
BC-10		Connecting Conveyor	200 TPH	PE
TH-5		Gypsum Transfer House #5	200 TPH	FE
BC-11		Connecting Conveyor	200 TPH	PE
TH-6		Gypsum Transfer House #6	200 TPH	FE
BC-12		Stacking Tripper Conveyor	200 TPH	PE
GSP		Gypsum Stockpile	15,600 Tons	FE
PSR-1		Traveling Portal Scraper Reclaimer	1,000 TPH	FE
BC-14		Reclaim Conveyor	1,000 TPH	PE
TH-7		Transfer House #7	1,000 TPH	FE
BC-13		Bypass Conveyor	200 TPH	PE
BC-15		Connecting Conveyor	1,000 TPH	PE
TH-1		Transfer House #1	1,000 TPH	FE
BC-16		Transfer Conveyor	1,000 TPH	PE
BL-1		Barge Loader	1,000 TPH	PE
BC-14		Reclaim Conveyor Extension	1,000 TPH	PE
TH-8		Transfer House #8	1,000 TPH	FE
BC-19		Transfer Conveyor	1,000 TPH	PE
TH-9		Transfer House #9	1,000 TPH	FE
BC-20		Transfer Conveyor	1,000 TPH	FE

Emission Unit ID	Emission Point ID	Emission Unit Description	Design Capacity	Control Device
TH-10		Transfer House #10	1,000 TPH	PE
BC-21		Transfer Conveyor to 21	1,000 TPH	FE
BUN-1		Clamshell Unloading Crane	1,000 TPH	
RH-4		Gypsum Unloading Hopper	30 tons	WSPE
RP-1		Gypsum Rotary Plow	750 TPH	FE
BC-17		Dock Connecting Conveyor	750 TPH	PE
TH-7		Transfer House #7	750 TPH	FE
BC-18		Bypass Conveyor	750 TPH	PE
TH-6		Transfer House #6	750 TPH	FE
3S		**Limestone Mineral Processing**		
VF-2		Limestone Reclaim Feeder 2	750 TPH	FE
VF-3		Limestone Reclaim Feeder 3	750 TPH	FE
BC-3		Limestone Tunnel Reclaim Conveyor	750 TPH	PE
FB-1		Emergency Limestone Reclaim Feeder/Breaker	750 TPH	None
TH-2		Limestone Transfer House 2	750 TPH	FE
BC-4		Limestone Silo A Feed Conveyor	750 TPH	PE
BC-5		Limestone Silo B Feed Conveyor	750 TPH	PE
BC-6		Limestone Silo C Feed Conveyor (future)	750 TPH	PE
LSB-1	6E	Limestone Silo A	900 tons	FF
LSB-2	7E	Limestone Silo B	900 tons	FF
LSB-3	8E	Limestone Silo C (future)	900 tons	FF
		Vibrating Bin Discharger (one per silo)	68.4 TPH	FE
LSWF-1 LSWF-2 LSWF-3		Limestone Weigh Feeder	68.4 TPH	FE
		Wet Ball Mill (one per silo)	68.4 TPH	FE
4S		**Dry Sorbent Material Handling**		
		Truck Unloading Connection (2)	25 TPH	FE
DSSB-1	10E	Dry Sorbent Storage Silo #1	500 Tons	FE/FF
DSSB-1	11E	Dry Sorbent Storage Silo #2	500 Tons	FE/FF
		Aeration Distribution Bins	4.6 TPH	FE
		De-aeration Bins	4.6 TPH	FE
		Rotary Feeder	4.6 TPH	FE
5S		**Coal Blending System**		

Emission Unit ID	Emission Point ID	Emission Unit Description	Design Capacity	Control Device
HTS-1		Transfer House #1	3,000 TPH	FE
HSC-1		Stacking Conveyor #1	3,000 TPH	PE
HTS-2A		Transfer House #2A	3,000 TPH	FE
HSC-2		Stacking Conveyor #2	3,000 TPH	PE
HTS-3		Transfer House #3	3,000 TPH	FE
HSC-3		Stacking Conveyor #3	3,000 TPH	PE
SH-1		Stacking Hopper SH-1 Transfer to SC-3 (receives coal from existing plant radial stacker R9)	3,000 TPH	FE
HSC-3 to High Sulfur Pile (CSA-2, existing)		Transfer from Stacking Conveyor HSC-3 to the High Sulfur Coal Pile located at existing North Yard Storage Area (CSA-2)	3,000 TPH	ST
HVF-1		Coal Reclaim Feeder 1	800 TPH	FE
HVF-2		Coal Reclaim Feeder 1	800 TPH	FE
HVF-3		Coal Reclaim Feeder 1	800 TPH	FE
HVF-4		Coal Reclaim Feeder 1	800 TPH	FE
HVF-1 through HVF-4 to HRC-1 (Transfer)_		Transfer from Vibrating Feeders HVF-1 through HVF-4 to Reclaim Conveyor HRC-1	1,600 TPH	FE
HRC-1		Coal Tunnel Reclaim Conveyor	1,600 TPH	PE
HTS-2B		Coal Transfer House #2B	1,600 TPH	FE
HRC-2		Reclaim Conveyor #2	1,600 TPH	PE
HTS-4		Coal Transfer House #4	1,600 TPH	FE
HRC-3		Reclaim Conveyor #3	1,600 TPH	PE
HTS-5		Coal Transfer House #5	1,600 TPH	FE
SB-1		Surge Bin #1	80 Tons	FE
HBF-1A		Belt Feeder 1A	800 TPH	PE
HBF-1B		Belt Feeder 1B	800 TPH	PE
HBF-1A/1B to BF-4E/4W (Transfer)		Transfer from Belt Feeders HBF-1A and HBF-1B to Existing Coal Conveyors 4E and 4W	1,600 TPH	FE
6S. 7S		**Emergency Quench Water System**		
6S	15E	Diesel Fired Engine for Quench Pump #1	60 Bhp	None
7S	16E	Diesel Fired Engine for Quench Pump #2	60 Bhp	None
9S		**Magnesium Hydroxide Material Handling System**		
MHM-1		Magnesium Hydroxide Mix Tank	1,000 Gallons	

Emission Unit ID	Emission Point ID	Emission Unit Description	Design Capacity	Control Device
MHM-2		Magnesium Hydroxide Mix Tank	1,000 Gallons	
11S		**Wastewater Treatment System Material Handling**		
		Truck Unloading Connection (2)	25 TPH	FE
		Lime Storage Silo #1	100 TPH	FE//FF
		Lime Storage Silo #2	100 TPH	FE//FF
		Wastewater Treatment Cake Stockpile	3,600 Tons	BE
FB-2		Filter Cake Feeder/Breaker	600 TPH	PE
BC-22		Transfer Conveyor 22	600 TPH	PE
TH-12		Transfer House #12	600 TPH	PE
		Fly Ash Handling System		
ME-1A	EP-1	Unit 1 Mechanical Exhauster		FF/Separator
ME-1B	EP-2	Unit 1 Mechanical Exhauster		FF/Separator
ME-1C	EP-3	Unit 1 Mechanical Exhauster		FF/Separator
ME-2A	EP-4	Unit 2 Mechanical Exhauster		FF/Separator
ME-2B	EP-5	Unit 2 Mechanical Exhauster		FF/Separator
ME-2C	EP-6	Unit 2 Mechanical Exhauster		FF/Separator
FAS-A	EP-7	Fly Ash Silo A	2,160 tons	FF Bin Vent
FAS-B	EP-8	Fly Ash Silo B	2,160 tons	FF Bin Vent
FAS-B	EP-8	Fly Ash Silo B	2,160 tons	FF Bin Vent
WFA-AA	F-1	Conditioned fly ash transfer from Silo A to Truck	360 TPH	MC
WFA-BA	F-2	Conditioned fly ash transfer from Silo B to Truck	360 TPH	MC
WFA-CA	F-3	Conditioned fly ash transfer from Silo C to Truck	360 TPH	MC
WFA-BA	F-4	Conditioned fly ash transfer from Silo A to Truck	360 TPH	MC
WFA-BB	F-5	Conditioned fly ash transfer from Silo B to Truck	360 TPH	MC
WFA-CB	F-6	Conditioned fly ash transfer from Silo C to Truck	360 TPH	MC
TC-A	EP-10	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
TC-B	EP-11	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
TC-C	EP-12	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
		Auxiliary Boiler		
Aux-1	Aux-ML-1	Auxiliary Boiler using Flue Gas Recirculation with Low NO_x Burners	663 MMBtu/hr	None
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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
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
C.F.R. ***or*** **CFR**	Code of Federal Regulations
CO	Carbon Monoxide
C.S.R. ***or*** **CSR**	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
dscm	Dry Standard Cubic Meter
FOIA	Freedom of Information Act
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr	Pounds per Hour
LDAR	Leak Detection and Repair
M	Thousand
MACT	Maximum Achievable Control Technology
MDHI	Maximum Design Heat Input
MM	Million
MMBtu/hr ***or*** **mmbtu/hr**	Million British Thermal Units per Hour
MMCF/hr ***or*** **mmcf/hr**	Million Cubic Feet per Hour
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 µm in diameter
PM_{10}	Particulate Matter less than 10µm in diameter
Ppb	Pounds per Batch
Pph	Pounds per Hour
Ppm	Parts per Million
Ppm_V or ppmv	Parts per Million by Volume
PSD	Prevention of Significant Deterioration
Psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
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;*

2.3.3. 45CSR19 – *Requirements for Pre-Construction Review, Determination of Emission Offsets for Proposed New or Modified Stationary Sources of Air Pollution and Emission Trading for Intrasource Pollutants.*

2.4. Term and Renewal

2.4.1. This permit supersedes and replaces previously issued Permit R13-2608D. 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 R13-2608, R13-2608A, R13-2608B, R13-2608C, R13-2608D, R13-2608E, 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.]

3.2. 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

4.1. Limitations and Standards

4.1.1. Limestone transferred across belt conveyor BC-1 to Transfer House #1 [TH-1] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.

4.1.2 Limestone transferred across belt conveyor BC-3 to Transfer House #2 [TH-2] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.

4.1.3. Gypsum transferred across belt conveyor BC-9 to Transfer House #4 [TH-4] shall be limited to a maximum transfer rate of 200 tons per hour and 1,700,000 tons per year.

4.1.4. Gypsum and wastewater treatment system cake transferred across belt conveyor BC-14 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,912,000 tons per year.

4.1.5. Gypsum transferred across belt conveyor BC-17 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 750 tons per hour and 1,200,000 tons per year.

4.1.6. Gypsum transferred across belt conveyor BC-19 to Transfer House #9 [TH-9] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,700,000 tons per year.

4.1.7. Coal transferred across belt conveyor HSC-1 shall be limited to a maximum transfer rate of 3,000 tons per hour and 5,732,544 tons per year.

4.1.8. Dry Sorbent (Trona or Hydrated Lime) for SO_3 mitigation shall be delivered to the facility at a maximum annual rate of 81,000 tons per year.

4.1.9. Liquid magnesium hydroxide shall be delivered to the facility at a maximum annual rate of 6,600,000 gallons per year.

4.1.10. Hydrated lime for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 3,200 tons per year.

4.1.11. Ferric Chloride for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 110,000 gallons per year.

4.1.12. Acid (hydrochloric or sulfuric) for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 170,000 gallons per year.

4.1.13. Polymer and organosulfide for the FGD wastewater treatment facility shall be delivered to the facility at a maximum annual rate of 13,500 gallons per year.

4.1.14. The diesel-fired engines [6S and 7S] used to power the emergency quench water system shall be limited to a total maximum combined annual operating schedule of 200 hours per year.

4.1.15. Compliance with all annual operating limits shall be determined using a twelve month rolling total. A twelve month rolling total shall mean the sum of the quantified operating data at any given time during the previous twelve (12) consecutive calendar months.

4.1.16. The permittee shall maintain a water truck on site and in good operating condition, and shall utilize same to apply water as often as is necessary in order to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads and other work areas where mobile equipment is used. The spraybar shall be equipped with spray nozzles, of sufficient size and number, so as to provide adequate coverage to the area being treated.

The pump delivering the water shall be of sufficient size and capacity so as to be capable of delivering to the spray nozzle(s) an adequate quantity of water and at a sufficient pressure, so as to assure that the treatment process will minimize the atmospheric entrainment of fugitive particulate emissions generated from the haulroads and work areas where mobile equipment is used.

4.1.17. Additionally, at least three times per year the permittee shall apply a mixture of water and an environmentally acceptable dust control additive hereafter referred to as solution to all unpaved haul roads. The solution shall have a concentration of dust control additive sufficient to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads.

4.1.18. The permittee shall not cause, suffer, allow or permit any source of fugitive particulate matter to operate that is not equipped with a fugitive particulate matter control system. This system shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter.

4.1.19. The installation and operation of the proposed Limestone Processing equipment [3S] shall be applicable to the limits and requirements set forth by 40CFR60 - Subpart OOO, "Standards of performance for non-metallic mineral processing plants."

a. The material transfers across the conveyors within the enclosed transfer stations and ball mill within the processing building will be limited to the opacity emissions from the building or building vents. The buildings will be limited to emissions of no visible opacity per 40CFR60.672(e)(1), and the vents from the buildings will be limited to an opacity of 7% and particulate emissions of 0.022 grains per dry standard cubic foot, per 40CFR60.672(e)(2).

b. The emissions from the baghouse on each of the limestone day bins will be limited to 7% opacity per 40CFR60.672(f).

c. All material transfer points outside of the buildings will be limited to a maximum 10% opacity per 40CFR60.672(b).

d. In order to comply with the emission and opacity limitations of this Subpart, the permittee shall employ dust suppression methods to minimize particulate emissions from the limestone processing equipment. In order to demonstrate compliance, in accordance to the requirements of the regulation, the applicant shall conduct performance testing and monitoring activities as set forth by this Subpart.

4.1.20. The maximum amount of fly ash handled by the fly ash handling system shall not exceed 800,000 tons per year on a dry (1% moisture) basis (i.e 980,000 tons per year at 20% moisture). Compliance with the throughput limit shall be determined using a rolling yearly total. A rolling yearly total shall mean the sum of the fly ash transferred for the previous twelve (12) consecutive calendar months.

4.1.21. PM emissions from Mechanical Exhausters ME-1A, ME-1B and ME-1C shall not exceed 0.16 lb/hr and 0.69 tpy individually nor 0.32 lb/hr and 1.38 tons per year combined.

4.1.22. PM emissions from Mechanical Exhausters ME-2A, ME-2B and ME-2C shall not exceed 0.15 lb/hr and 0.65 tpy individually nor 0.30 lb/hr and 1.30 tons per year combined.

4.1.23. PM emissions from Bin Vent Filters BVF-A, BVF-B and BVF-C shall not exceed 0.75 lb/hr nor 3.25 tpy combined.

4.1.24. PM emissions from the transfer of conditioned fly ash from the silos to trucks (WFA-AA, WFA-AB, WFA-BA, WFA-BB, WFA-CA, and WFA-CB) shall not exceed 0.07 pounds per hour nor 0.09 tons per year combined.

4.1.25. **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. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.1. and 4.1.2. of this permit, the permittee shall monitor the hourly and annual limestone transfer rates across belt conveyor BC-1 to Transfer House #1 [TH-1] and across belt conveyor BC-3 to Transfer House #2 [TH-2].

4.2.2. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.3., 4.1.4., 4.1.5. and 4.1.6. of this permit, the permittee shall monitor the hourly and annual gypsum and wastewater treatment cake transfer rates across belt conveyors BC-9 to Transfer House #4 [TH-4], BC-14 to Transfer House #7 [TH-7], BC-17 to the Transfer House #7 Extension, and BC-19 to Transfer House #9 [TH-9].

4.2.3. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.7. of this permit, the permittee shall monitor the hourly and annual coal transfer rates across belt conveyor HSC-1 to Transfer Station #2A.

4.2.4. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the SO_3 mitigation system, as set forth by Section 4.1.8. and 4.1.9. of this permit, the permittee shall monitor the on-site delivery of dry sorbent (including trona and hydrated lime) and liquid magnesium hydroxide.

4.2.5. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the FGD wastewater treatment system, as set forth by Sections 4.1.10. through 4.1.13. of this permit, the permittee shall monitor the on-site delivery of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide.

4.2.6. For the purpose of determining compliance with the operating limits set forth by Section 4.1.14. of this permit, the permittee shall monitor the operating schedule of the diesel-fired engine [6S and 7S] used to power the emergency quench water system.

4.2.7. For the purpose of determining compliance with the limits associated with disposal of dry fly ash, as set forth by Section 4.1.20 of this permit, the permittee shall monitor and record the amount of dry fly ash disposed of.

4.2.8. For the purpose of determining compliance with the operating limits set forth by Section 4.1.17. of this permit, the permittee shall monitor and record the date that chemical solution is applied to the haulroads along with the amount and concentration of the solution applied.

4.3. Testing Requirements

4.3.1. For the purpose of determining compliance with the performance testing requirements of 40 C.F.R. Part 60, Subpart OOO, as set forth by Section 4.1.19. of this permit, the permittee shall conduct compliance testing of the permitted facility within 180 days of the equipment start-up. These tests will be used to determine the particulate matter emissions generated from the open transfer points and processing operations. The testing methods to be employed are as follows:

Pollutant	USEPA Test Method*
Determination of the Opacity of Emissions	9

* Per 40CFR60, Appendix A

The permittee shall submit to the Director of the DAQ a test protocol detailing the proposed test methods, date, and time testing is to take place, testing locations, and any other relevant information. The test protocol must be received by the Director no less than thirty (30) days prior to the date the testing is to take place. The Director shall be notified at least fifteen (15) days in advance of the actual dates and times during which the tests will be conducted. The results of emissions testing shall be submitted to the DAQ within thirty (30) days of completion of testing.

4.3.2. Within 120 days of startup of the dry ash handling system, the permittee shall perform or have performed EPA approved tests (or other methods as approved by WVDAQ) to determine maximum PM emissions from any one of the Silo Bin Vent Filters (BVF-A, BVF-B or BVF-C).

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 the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.1. of this permit, the permittee shall maintain monthly records of the amount of limestone transferred across the monitored belt conveyors.

4.4.5. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.2. of this permit, the permittee shall maintain monthly records of the amount of gypsum and wastewater treatment cake transferred across the monitored belt conveyors.

4.4.6. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.3. of this permit, the permittee shall maintain monthly records of the amount of coal transferred across the monitored belt conveyor.

4.4.7. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.4. of this permit, the permittee shall maintain monthly records of the amount of dry sorbent (trona and hydrated lime) and liquid magnesium hydroxide delivered to the facility via truck.

4.4.8. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.5. of this permit, the permittee shall maintain monthly records of the amount of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide delivered to the facility via truck.

4.4.9. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.6. of this permit, the permittee shall maintain monthly records of the hours of operation of the diesel-fired engines [6S and 7S].

4.4.10. For the purposes of determining compliance with Section 4.1.16., 4.1.17., and 4.1.18. of this permit, the permittee shall maintain records of the amount of dust control additive used at the facility and the dates the solution was applied.

4.4.11. All records produced in accordance to the requirements set forth by Section 4.4. of this permit shall be maintained on-site for a period of no less than five (5) years and made available to the Director or his duly authorized representative upon request. At a time prior to being submitted to the Director, all records shall be certified and signed by a "Responsible Official" or a duly authorized representative, utilizing the attached Certification of Data Accuracy statement.

4.4.12. For the purposes of determining compliance with the maximum throughput limit set forth in Condition 4.1.20 above, the facility shall maintain monthly (and calculated rolling yearly total) records of the amount of fly ash handled by the Units 1 and 2 fly ash system.

5.0. Source-Specific Requirements for the Auxiliary Boiler (Aux-1)

5.1. Limitations and Standards

5.1.1. The following conditions and requirements are specific to the Boiler Aux-1:

a. Emissions from the boiler shall not exceed the following limits:

Pollutant	lb/hr	tpy
SO_2	39.78*	17.42
NO_x	99.45	43.56
CO	206.86	90.60
VOC	0.95	0.41
PM (filterable +condensable.)	15.63	6.85
PM_{10} (filterable +condensable)	10.90	4.77
$PM_{2.5}$ (filterable +condensable)	7.34	3.22
CO_2	105,606.4	46,255.6
N_2O	0.88	0.38
CH_4	4.38	1.92
CO_{2e} (Total)	105,971.18	46,413.72
Formaldehyde	0.29	0.13
Benzene	0.01	0.01
Ethylbenzene	0.01	0.01
Toluene	0.03	0.02
Xylene	0.01	0.01
Naphthalene	0.01	0.01

* This limit makes 40 CFR §60.42b(k)(2) applicable and excludes the unit from limitations of 40 CFR §60.42b(k)(1). This limit satisfies the limitation in 45 CSR §10-3.1.b.

b. Boiler Aux-1 shall be fitted with Low NO_x burners and shall utilize Flue Gas Recirculation.

c. The permittee shall limit the annual capacity of the boiler to no more than 10 percent by limiting the annual average heat input of the boiler to 580,788 MMBtu per year. Compliance with this limit shall be satisfied though compliance with the annual fuel usage limit in item d of this condition.
[40 CFR §60.44b(c) and §63.7575; and 45 CSR §2-8.4.a.1.]

d. For the purpose of complying with the SO_2 limits in item a of this condition, the Boiler Aux-1 shall not consume more than 4,736 gallons of fuel oil (distillate oil) per hour nor more than 4,148,736 gallons per year. Such fuel oil can not contain more than 600 ppm or 0.06 % of

sulfur, which makes the sulfur dioxide potential for this unit at no greater than 0.06 lb/MMBtu.
[40 CFR §60.42.b(k)(2), §60.43b(h)(5), and §60.48b(j)(2); and 45 CSR §10-10.2]

e. Opacity from boiler shall not exceed 20% based on a 6-minute average, except for one 6-minute period per hour of not more than 27% opacity, except during periods of startup, shutdown, or malfunction.
[40 CFR §§60.43b(f) & (g)]

f. Visible emissions from the boiler shall not exceed 10 percent opacity based on a six minute block average, except during periods of startup, shutdown, or malfunction.
[45 CSR §2-3.1, and §2-9.1.]

g. The permittee shall conduct an initial tune-up of the unit before January 31, 2016 (40 CFR §63.7510(e)) and subsequent tune-ups once every 5 years thereafter in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. Subsequent tune-ups shall be conducted no later than 61 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 72 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 (you 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 maintain;

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]

5.1.2. **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.]

5.2. Monitoring Requirements

5.2.1. In order to determine compliance with Condition 5.1.1.d of this permit, the permittee shall monitor and record the amount of fuel oil combusted by Boiler Aux-1 on a monthly basis. Compliance with fuel usage limitations in item d will constitute compliance with the emission limitations of item a. of Condition 5.1.1. Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.49b(d)(2); and 45 CSR §2-8.3c., §§10-8.2.c.3., and 8.3.c.]

5.2.2. The permittee shall obtain records indicating the fuel oil received at the facility for Boiler Aux I meets the specification of distillate oil as defined in 40 CFR §60.41b and sulfur content stated in item d. of Condition 5.1.1. from the fuel supplier. Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.49b(r)(1) and 45 CSR §§10-8.2.c.3.]

5.2.3. The permittee shall conduct subsequent visible emission observations of the emission point for Boiler Aux-1 at least once every 12 months from the date of the most recent observation. Such observations be conducted using Method 9 of Appendix A-4 of Part 60. If visible emissions are observed, the permittee must follow the subsequent observation schedule in 40 CFR §60.48b(a)(1)(ii) through (iv) as applicable. Record of Method 9 observation shall contain the following:

a. Dates and time intervals of all opacity observation periods;

b. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

c. Copies of all visible emission observer opacity field data sheets;

If the most recent observation is less than 10 percent opacity, the permittee may use Method 22 of Appendix A-7 of Part 60 to demonstrate compliance in lieu of using Method 9. The use of Method 22 observations must be in accordance with the length of observation and frequency as outline in 40 CFR §60.48b(a)(2)(i) through (ii) as applicable. Record of Method 9 observation shall contain the following

a. Dates and time intervals of all visible emissions observation periods;

b. Name and affiliation for each visible emission observer participating in the performance test;

c. Copies of all visible emission observer opacity field data sheets; and

d. Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

Records of observations shall be maintained in accordance with Condition 3.4.1.
[40 CFR §§60.48b(a) and 60.49b(f); and 45 CSR §2-8.1(a)]

5.3. Testing Requirements

[Reserved]

5.4. Recordkeeping Requirements

5.4.1. **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.

5.4.2. **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.

5.4.3. **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.

5.4.4. The permittee shall keep the following records in accordance with 40CFR§63.7555. This includes but not limited to the following information during the tune up as required in Condition 4.1.1.g. and 40 CFR §63.7540:

a. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater. If concentrations of NO_x were taken during the tune-up of the unit, record of such measurements shall be included;

b. A description of any corrective actions taken as a part of the tune-up; and.
[40 CFR §§63.7540(a)(10)(vi) and 63.7555]

5.5. Reporting Requirements

5.5.1. The permittee shall submit a "Notification of Compliance Status" for Boiler Aux-1 to the Director before the close of business on the sixtieth (60th) day after completion of the initial compliance demonstration as required in 40 CFR §63.7530(f). Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the information specified in 40 CFR §§63.7545(e)(1), and (8), which included a statement the initial tune-up for boiler was completed.
[40CFR§63. 7530(d), and §63. 7545(e)]

5.5.2. The permittee shall submit "5- year Compliance Reports" to the Director for Boiler Aux-1 with the first report being submitted by no later than January 31, 2016, and subsequent reports are due every 5 years from 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 biennial 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)]

5.5.3. The permittee shall report any observation made in accordance with Condition 5.2.3. that indicate visible emissions in excess of either items e and/or f of Condition 5.1.1. made during January 1 to June 30 in the facility's Title V Semi Annual Compliance Report or July 1 to December 31 as part of the facility's Title V Annual Compliance Report. Such report shall include the record of the recorded observation in accordance with Condition 5.2.3. and measures taken as result of the observation. This reporting requirement can be satisfied by including the results of the exceeded observation(s) with the facility's quarterly opacity report and list the exceedance in the facility's Title V annual compliance certification report.
[40 CFR §60.49b(h) and 45 CSR §2-8.3b.]

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.

west virginia department of environmental protection
Division of Air Quality

Phase II Acid Rain Permit

Plant Name: **Mitchell Power Station**		Permit #: **R33-3948-2027-6**
Affected Unit(s): **1, 2**		
Operator: **Kentucky Power Company**		ORIS Code: **3948**
Effective Date	From: **January 1, 2023**	To: **December 31, 2027**

Contents:

1. Statement of Basis.

2. SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3. Comments, notes and justifications regarding permit decisions and changes made to permit application forms during the review process, and any additional requirements or conditions.

4. The permit application forms submitted for this source, as corrected by the West Virginia Division of Air Quality. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

---

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with W. Va. Code §22-5-4(a)(16) and Titles IV and V of the Clean Air Act, the West Virginia Department of Environmental Protection, Division of Air Quality issues this permit pursuant to 45CSR33 and 45CSR30.

Permit Approval

Laura M. Crowder Digitally signed by: Laura M. Crowder DN: CN = Laura M. Crowder email = Laura.M.Crowder@wv.gov C = US O = West Virginia Department of Environmental Protection OU = Division of Air Quality Date: 2022.12.19 12:21:39 -05'00'

Laura M. Crowder, Director
Division of Air Quality

December 19, 2022
Date

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No. **1**

SO_2 Allowances	**Year**				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	18995	18995	18995	18995	18995
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A
The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).					

NO_X Requirements	**2023**	**2024**	**2025**	**2026**	**2027**
NO_X Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50
Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers. In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.					

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No. **2**

SO_2 Allowances	Year				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	19656	19656	19656	19656	19656
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A
The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).					

NO_X Requirements	2023	2024	2025	2026	2027
NO_X Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50
Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers. In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.					

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/3 /202

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☑ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Mitchell (WV)	West Virginia	3948

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
   (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
   (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
   (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
   (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
   (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
   (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
   (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
   (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, a Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision o the Act, including the provisions o title I o the Act relating to applicable National Ambient Air Quality Standards o State Implementation Plans;

(2) Limiting the number o allowances a source can hold; provided, that the number o allowances held by the source shall not affect the source's obligation o comply with any other provisions o the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, o limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date.

am authorized o make this submission o behalf o the owners and operators o the affected source o affected units for which the submission is made. certify under penalty o law that have personally examined, and am familiar with, the statements and information submitted this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best o my knowledge and belief true, accurate, and complete. am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Scott A. Weaver	
Signature Scott A Weaver	Date 4/7/2022

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

Page 1

This submission is: ☐ New ☑ Revised

STEP 1
Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

Plant Name	State	Plant Code
Mitchell	WV	3948

STEP 2

Identify each affected Group 1 and Group 2 boiler using the unit IDs from the current Certificate of Representation covering the facility. Also indicate the boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom, and select the compliance option for each unit by making an 'X' in the appropriate row and column.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	X	X				
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)						
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)						
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)						
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						

STEP 2, cont'd

Plant Name (From Step 1)	Mitchell

	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(i) NO_X Averaging Plan (include NO_X Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_X Averaging (check the NO_X Averaging Plan box and include NO_X Averaging Form))						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						

STEP 3: Identify the first calendar year in which this plan will apply.

January 1, 2019

STEP 4: Read the special provisions and certification, enter the name of the designated representative, sign and date.

Special Provisions

General. This source is subject to the standard requirements in 40 CFR 72.9. These requirements are listed in this source's Acid Rain Permit.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Scott A. Weaver	
Signature	Scott A Weaver	Date 12-18-18

West Virginia Department of Environmental Protection
Joe Manchin, III
Governor
Division of Air Quality
Randy C. Huffman
Cabinet Secretary

Class II General Permit
G60-C Registration to Modify

for the
Prevention and Control of Air Pollution in regard to the
Construction, Modification, Relocation, Administrative Update and
Operation of Emergency Generators

The permittee identified at the facility listed below is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of General Permit G60-C.

G60-C057A

Issued to:
AEP Generation Resources Inc.
Mitchell Plant
051-00005

William F. Durham
Director

Issued: August 8, 2014

This Class II General Permit Registration will supercede and replace G60-C057.

Facility Location:	State Route 2, Moundsville, Marshall County, West Virginia
Mailing Address:	P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generation Facility
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Registration Type:	Modification
Description of Change:	Installation of two additional generators (EG-1 and EG-2) to black start the facility.

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 or registration 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.

Unless otherwise stated WVDEP DAQ did not determine whether the permittee is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart ZZZZ.

All registered facilities under Class II General Permit G60-C are subject to Sections 1.0, 2.0, 3.0, and 4.0.

The following sections of Class II General Permit G60-C apply to the registrant:

Section 5	Reciprocating Internal Combustion Engines (R.I.C.E.)	X
Section 6	Tanks	X
Section 7	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40CFR60 Subpart IIII)	X
Section 8	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (40CFR60 Subpart JJJJ)	X

Emission Units

Emission Unit ID	Emission Unit Description (Make, Model, Serial No.)	Year Installed	Design Capacity (Bhp/rpm)
LPG	Generac SG080, 127 BHP Engine (Spark Ignition Engine)	2013	127/1,800
EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	2014	3,717/1,800
EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	2014	3,004/1,800

Emission Limitations

Source ID#	Nitrogen Oxides		Carbon Monoxide		Volatile Organic Compounds	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
LPG	0.74	0.19	21.75	5.44	0.22	0.06
EG-1	59.9	14.98	7.66	1.92	0.94	0.24
EG-2	36.4	9.1	4.85	1.21	1.18	0.03
TOTAL	97.04	24.27	34.26	8.57	2.34	0.33

West Virginia Department of Environmental Protection

Austin Caperton
Cabinet Secretary

Class II General Permit
G60-D

for the
Prevention and Control of Air Pollution in regard to the
Construction, Modification, Relocation, Administrative Update and
Operation of Emergency Generators

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45CSR13 — Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation.

William F. Durham
Director, Division of Air Quality

Issued: May 9, 2018

Class II General Permit G60-D supersedes and replaces General Permit G60-C issued on May 21, 2009.

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.

General Permit G60-D authorizes the construction, modification, administrative update and/or operation of emergency generators.

Table of Contents

1.0. Emission Units

1.1. General Permit Registration

1.1.1. All emission units covered by this permit are listed on the issued G60-D Registration.

2.0. General Conditions

2.1. Purpose

The purpose of this Class II General Permit is to authorize the construction, modification, administrative update, relocation, and operation of eligible emergency generators through a Class II General Permit registration process. The requirements, provisions, standards and conditions of this Class II General Permit address the prevention and control of regulated pollutants from the operation of emergency generator(s).

2.2. Authority

This permit is issued in accordance with West Virginia air pollution control law W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.2.1. 45 CSR 13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation.*

2.3. Applicability

2.3.1. All emergency generators installed for the purpose of allowing key systems to continue to operate without interruption during times of utility power outages, including emergency generators installed at Title V(major) facilities and other facilities having additional point sources of emissions, are eligible for Class II General Permit registration except for:

a. Any emergency generator which is a major source as defined in 45CSR14, 45CSR19 or 45CSR30;
b. Any emergency generator subject to the requirements of 45CSR14, 45CSR15, 45CSR19, 45CSR25, 45CSR27, 45CSR30, 45CSR34;
c. Any emergency generator whose estimated hours of operation exceeds 500 hours per year;
d. Any emergency generator located in or which may significantly impact an area which has been determined to be a nonattainment area. Unless otherwise approved by the Secretary.
e. Any emergency generator which will require an individual air quality permit review process and/or individual permit provisions to address the emission of a regulated pollutant or to incorporate regulatory requirements other than those established by General Permit G60-D.
f. Any emergency generator which is/are part of an emergency demand response program.

2.3.2. For the purposes of General Permit G60-D, *emergency generator* means a generator whose purpose is to allow key systems to continue to operate without interruption during times of utility power outages.

2.3.3. The West Virginia Division of Air Quality reserves the right to reopen this permit or any authorization issued under this permit if the area in which the affected facility is located is federally designated as non-attainment for specified pollutants. If subsequently any proposed construction, modification and/or operation does not demonstrate eligibility and/or compliance with the requirements, provisions, standards and conditions of this General Permit, this General

Permit registration shall be denied and an individual permit for the proposed activity shall be required.

2.3.4. Except for emergency diesel generators, all emission units covered by this permit, unless they are classified as De Minimis Sources in 45CSR13 Table 45-13B, must be fueled with pipeline-quality natural gas, field gas, propane gas, or equivalent with a maximum sulfur content of 20 grains of sulfur per 100 standard cubic feet and a maximum H_2S content of 0.25 grains per 100 cubic feet of gas (maximum allowed to have in natural gas sold for delivery through the interstate pipeline system).
[45CSR§13-5.11]

2.4. Definitions

2.4.1. 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.

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

2.4.3. "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.

2.4.4. The terms established in applicable definitions codified in the Code of Federal Regulations including 40 CFR Part 60 NSPS Subparts A, IIII and JJJJ or 40 CFR Part 63 MACT Subparts A and ZZZZ shall also apply to those sections of General Permit G60-D where these subparts are incorporated or otherwise addressed.

2.5. Acronyms

CAAA	Clean Air Act Amendments	NO_x	Nitrogen Oxides
CBI	Confidential Business Information	NSCR	Non Selective Catalytic Reduction
CEM	Continuous Emission Monitor	NSPS	New Source Performance Standards
CES	Certified Emission Statement		
CFR	Code of Federal Regulations	PM	Particulate Matter
CO	Carbon Monoxide	$PM_{2.5}$	Particulate Matter less than 2.5 µm in diameter
CSR	Code of State Rules		
DAQ	Division of Air Quality	PM_{10}	Particulate Matter less than 10 µm in diameter
DEP	Department of Environmental Protection	ppm	Parts per million
FOIA	Freedom of Information Act	ppm_v	Parts per million by Volume
HAP	Hazardous Air Pollutant	PSD	Prevention of Significant Deterioration
HP	Horsepower		
lb/hr	Pounds per hour	psi	Pounds per square inch
LDAR	Leak Detection and Repair	RICE	Reciprocating Internal Combustion Engine
M or m	Thousand		
MACT	Maximum Achievable Control Technology	SCR	Selective Catalytic Reduction
		SIC	Standard Industrial Classification
MDHI	Maximum Design Heat Input		
MM or mm	Million	SIP	State Implementation Plan
MMBTU/hr	Million British Thermal Units Per Hour	SO_2	Sulfur Dioxide
		TAP	Toxic Air Pollutant
MMCF/hr	Million Cubic Feet per Hour	TPY	Tons per year

N/A	Not Applicable	TSP	Total Suspended Particulate
NAAQS	National Ambient Air Quality Standards	USEPA	United States Environmental Protection Agency
NESHAPS	National Emissions Standards for Hazardous Air Pollutants	UTM	Universal Transverse Mercator
		VEE	Visual Emissions Evaluation
LAT	Latitude	VOC	Volatile Organic Compounds
LON	Longitude	VRU	Vapor Recovery Unit

2.6. Permit Expiration and Renewal

2.6.1. This Class II General 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.

2.6.2. General Permit registrations granted by the Secretary shall remain valid, continuous and in effect unless suspended or revoked by the Secretary. If the Class II General Permit registration is subject to action or change, existing registrations will continue to be authorized and subject to the previously established permit conditions. **[45CSR§13-10.2, 45CSR§13-10.3]**

2.6.3. The Secretary shall review and may renew, reissue or revise this Class II General Permit for cause. The Secretary shall define the terms and conditions under which existing General Permit registrations will be eligible for registration under a renewed, reissued, or revised General Permit and provide written notification to all General Permit registrants (or applicants). This notification shall also describe the registrant's (or applicant's) duty or required action and may include a request for additional information that may be required by any proposed general permit renewal, reissuance or revision.

2.7. Administrative Update to General Permit Registration

2.7.1. The registrant may request an administrative update to their General Permit registration as defined in and according to the procedures specified in 45CSR§13-4.
[45CSR§13-4.]

2.8. Modification to General Permit Registration

2.8.1. The registrant may request a minor permit modification to their General Permit registration as defined in and according to the procedures specified in 45CSR§13-5. **[45CSR§13-5.]**

2.9. Duty to Comply

2.9.1. The registered affected facility shall be constructed and operated in accordance with the information filed in the General Permit Registration Application and any amendments thereto. The Secretary may suspend or revoke a General Permit registration if the plans and specifications upon which the approval was based are not adhered to.

2.9.2. The registrant must comply with all applicable conditions of this Class II General Permit. Any General Permit noncompliance constitutes a violation of the West Virginia Code, and/or the Clean Air Act, and is grounds for enforcement action by the Secretary or USEPA.

2.9.3. Violation of any of the applicable requirements, provisions, standards or conditions contained in this Class II General Permit, or incorporated herein by reference, may subject the registrant 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.

2.9.4. Registration under this Class II General Permit does not relieve the registrant 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.

2.10. Inspection and Entry

2.10.1. The registrant 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 enter upon the registrant'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 Class II General 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 this Class II General Permit;

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.

2.11. Need to Halt or Reduce Activity not a Defense

2.11.1. It shall not be a defense for a registrant in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Class II General 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.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonably 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 this Class II General 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. In any enforcement proceeding, the registrant seeking to establish the occurrence of an emergency has the burden of proof.

2.12.3. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Federally-Enforceable Requirements

2.13.1. All terms and conditions in this permit are enforceable by the Secretary, USEPA, and citizens under the Clean Air Act.

2.13.2. Those provisions specifically designated in the permit as "State-enforceable only" shall become "Federally-Enforceable" requirements upon SIP approval by the USEPA.

2.14. Duty to Provide Information

2.14.1. The registrant shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this Class II General Permit Registration or to determine compliance with this General Permit. Upon request, the registrant shall also furnish to the Secretary copies of records required to be kept by the registrant. For information claimed to be confidential, the registrant 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 registrant shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 CFR Part 2.

2.15. Duty to Supplement and Correct Information

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

2.16. Credible Evidence

2.16.1. Nothing in this Class II General 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 defenses otherwise available to the registrant including but not limited to any challenge to the credible evidence rule in the context of any future proceeding.

2.17. Severability

2.17.1. The provisions of this Class II General Permit are severable. If any provision of this Class II General Permit, or the application of any provision of this Class II General Permit to any circumstance is held invalid by a court of competent jurisdiction, the remaining Class II General Permit terms and conditions or their application to other circumstances shall remain in full force and effect.

2.18. Property Rights

2.18.1. Registration under this Class II General Permit does not convey any property rights of any sort or any exclusive privilege.

2.19. Notification Requirements

2.19.1. The registrant shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit except as required under section 1.1.3 (e.g. 15 days after alternative operating scenario startup).

2.20. Suspension of Activities

2.20.1. In the event the registrant should deem it necessary to suspend, for a period in excess of one (1) year, all operations authorized by this permit, the registrant shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the one (1) year of the suspension period.

2.21. Transferability

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

3.0. Facility-Wide Requirements

3.1. Siting Criteria

3.1.1. All persons submitting a Class II General Permit Registration Application to construct, modify or relocate an emergency generator shall be subject to the following siting criteria:

a. No emission unit shall be constructed, located or relocated within 300 feet of any occupied dwelling, business, public building, school, church, community building, institutional building or public park. An owner of an occupied dwelling or business may elect to waive the 300 foot siting criteria.

b. Any person proposing to construct, modify or relocate any emission unit(s) within 300 feet of any occupied dwelling, business, public building, school, church, community, institutional building or public park may elect to apply for an individual permit pursuant to 45CSR13.

3.2. Limitations and Standards

3.2.1. **Open burning.** The open burning of refuse by any person is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.2.2. **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 or allow 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.]

3.2.3. **Asbestos.** The registrant 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 CFR § 61.145, 40 CFR § 61.148, and 40 CFR § 61.150. The registrant, 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 registrant is subject to the notification requirements of 40 CFR § 61.145(b)(3)(i). USEPA, the Division of Water and Waste Management (DWWM), and the Department of Health and Human Resources (DHHR) – Office of Environmental Health Services (OEHS) require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.2.4. **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]***

3.2.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one, twelve (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. *This requirement does not apply to emergency generator(s) permitted to operate only 500 hours per year.*
[45CSR§13-10.5.]

3.2.6. **Standby plan for reducing emissions.** When requested by the Secretary, the registrant 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.]

3.3. Monitoring Requirements

See Section 4.2.

3.4. Testing Requirements

3.4.1. **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 registrant shall conduct test(s) to determine compliance with the emission limitations set forth in this Class II General Permit and/or established or set forth in underlying documents. The Secretary, or their duly authorized representative, may at his/her option witness or conduct such test(s). Should the Secretary exercise his/her 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 CFR 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 Class II General 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 require, approve or specify additional testing or alternative testing to the test methods specified in the Class II General 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 3.4.1.a. of this general 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 Class II General Permit shall be conducted in accordance with an approved test protocol. 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 registrant 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 registrant 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 and any operating parameters required to be monitored. The report shall include the following: the certification described in paragraph 3.6.1; 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]

3.5. Recordkeeping Requirements

3.5.1. **Retention of records.** The registrant 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. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Said records shall be maintained on site or in a readily accessible off-site location maintained by the registrant for a period of five (5) years. Said records shall be readily available to the Secretary of the Division of Air Quality or his/her duly authorized representative for expeditious inspection and review. Any records submitted to the agency pursuant to a requirement of this permit or upon request by the Secretary shall be certified by a responsible official. Where appropriate, the registrant may maintain records electronically.

3.5.2. **Odors.** For the purposes of 45CSR4, the registrant 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.*]**

3.6. Reporting Requirements

3.6.1. **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.

3.6.2. **Confidential information.** A registrant 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.

3.6.3. **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, e-mailed 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 SE
Charleston, WV 25304-2345
-or-
DEPAirQualityReports@wv.gov
(preferred)

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

3.6.4. **Emission inventory.** At such time(s) as the Secretary may designate, the registrant 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 DAQ. 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.

3.6.5. **Operating Fee**

The registrant will be subject to (a) or (b) below dependent on the source status of the facility:

(a) In accordance with 45CSR22 – Air Quality Management Fee Program, the registrant shall not operate nor cause to operate the permitted facility or other associated facilities on the same or contiguous sites comprising the plant without first obtaining and having in current effect a Certificate to Operate (CTO). Such Certificate to Operate (CTO) shall be renewed annually, shall be maintained on the premises for which the certificate has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

(b) 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.

4.0. Source-Specific Requirements

4.1. Limitations and Standards

4.1.1. *Operation and Maintenance of Air Pollution Control Equipment and Emission Reduction Devices.* The registrant shall, to the extent practicable, install, maintain, and operate all pollution control equipment and emission reduction devices listed in the issued General Permit Registration and associated monitoring equipment to comply with limits set forth in this General Permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary. **[45CSR§13-5.11.]**

4.1.2. *Applicability of State and Federal Regulations.* The registrant is subject to the provisions of the following State Rules and Federal Regulations, to the extent applicable based on its registration:

a. 45CSR13 - Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, and Procedures for Evaluation
b. 45CSR16 - Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60
c. 45CSR22 - Air Quality Management Fee Program
d. 45CSR30 – Requirements for Operating Permits
e. 40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
f. 40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
g. 40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

4.2. Recordkeeping Requirements

4.2.1. *Monitoring information.* The registrant 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.

4.2.2. *Record of Maintenance of Air Pollution Control Equipment and Emission Reduction Devices.* For all pollution control equipment and emission reduction devices listed in the General Permit Registration, the registrant shall maintain accurate records of all required pollution control equipment and emission reduction devices inspection and/or preventative maintenance procedures specifically required in this General Permit.

4.2.3. *Record of Malfunctions of Air Pollution Control Equipment and Emission Reduction Devices.* For all air pollution control equipment and emission reduction devices listed in the General Permit Registration, the registrant shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment and emission reduction devices during which excess emissions above the applicable permit limit 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.

5.0. Source-Specific Requirements [Reciprocating Internal Combustion Engine(s) (RICE)]

5.1. Limitations and Standards

5.1.1. For the purposes of General Permit G60-D, *emergency generator* means a generator whose purpose is to allow key systems to continue to operate without interruption during times of utility power outages.

5.1.2. *Regulated Pollutant Limitation.* The registrant shall not cause, suffer, allow or permit emissions of any regulated pollutant listed in the General Permit Registration to exceed the emission limit (pounds per hour and tons per year) recorded with the registrant's General Permit Registration. The registrant may request a modification or administrative update to these emission limits.

5.1.3. *Maximum Hourly Limitation.* The maximum hours of operation for any registered emergency generator listed in the General Permit Registration application shall not exceed 500 hours per year. Compliance with the Maximum Yearly Hourly Operation Limitation shall be determined using a twelve-month rolling total. A twelve-month rolling total shall mean the sum of the hours or operation at any given time during the previous twelve consecutive calendar months.

5.1.4. The applicable emergency generator(s) shall be operated and maintained as follows:

a. In accordance with the manufacturer's recommendations and specifications or in accordance with a site specific maintenance plan; and,
b. In a manner consistent with good operating practices.

5.1.5. Requirements for Use of Catalytic Reduction Devices

a. Rich-burn engine(s) equipped with non-selective catalytic reduction (NSCR) air pollution control devices shall be fitted with a closed-loop, automatic air/fuel ratio controller to ensure emissions of regulated pollutants do not exceed the emission limit listed in the General Permit Registration for any engine/NSCR combination under varying load. The closed-loop, automatic air/fuel ratio controller shall control a fuel metering valve to ensure a fuel-rich mixture and a resultant exhaust oxygen content of less than or equal to 2%.

b. Lean-burn engine(s) equipped with selective catalytic reduction (SCR) air pollution control devices shall be fitted with a closed-loop automatic feedback controller to ensure emissions of regulated pollutants do not exceed the emission limit listed in the General Permit Registration for any engine/SCR combination under varying load. The closed-loop automatic feedback controller shall provide proper and efficient operation of the engine, ammonia injection and SCR device, monitor emission levels downstream of the catalyst element and limit ammonia slip to less than 10 ppm_v.

c. Lean-burn engine(s) equipped with oxidation catalyst air pollution control devices shall be fitted with a closed-loop automatic air/fuel ratio feedback controller to ensure emissions of regulated pollutants do not exceed the emission limit listed in the General Permit Registration for any engine/oxidation catalyst combination under varying load. The closed-loop, automatic air/fuel ratio controller shall control a fuel metering valve to ensure a lean-rich mixture.

d. For engine(s) equipped with a catalyst, the registrant shall monitor the temperature to the inlet of the catalyst and in accordance with manufacturer's specifications; a high temperature alarm shall shut off the engine before thermal deactivation of the catalyst occurs. If the engine shuts off due to high temperature, the registrant shall also check for thermal deactivation of the catalyst before normal operations are resumed.

e. The registrant shall follow a written operation and maintenance plan that provides the periodic and annual maintenance requirements.

5.1.6. The registrant shall comply with all applicable NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

5.1.7. The emission limitations specified in section 5.1.2 shall apply at all times except during periods of start-up and shut-down provided that the duration of these periods does not exceed 30 minutes per occurrence. The registrant shall operate the engine in a manner consistent with good air pollution control practices for minimizing emissions at all times, including periods of start-up and shut-down. The emissions from start-up and shut-down shall be included in the twelve (12) month rolling total of emissions. The registrant shall comply with all applicable start-up and shut-down requirements in accordance with 40 CFR Part 60, Subparts IIII, JJJJ and 40 CFR Part 63, Subpart ZZZZ.

5.2. Monitoring Requirements

5.2.1. Catalytic Reduction Devices

a. The registrant shall regularly inspect, properly maintain and/or replace catalytic reduction devices and auxiliary air pollution control devices to ensure functional and effective operation of the engine's physical and operational design. The registrant shall ensure proper operation, maintenance and performance of catalytic reduction devices and auxiliary air pollution control devices by:

1. Maintaining proper operation of the automatic air/fuel ratio controller or automatic feedback controller.

2. Following the catalyst manufacturer emissions related operating and maintenance recommendations, or develop, implement, or follow a site-specific maintenance plan.

5.3. Recordkeeping Requirements

5.3.1. To demonstrate compliance with general permit condition 5.1.3, the registrant shall maintain records of the hours of operation of the emergency generator(s) on a monthly basis.

5.3.2. To demonstrate compliance with general permit section 5.1.4, the registrant shall maintain records of the maintenance performed on each emergency generator.

5.3.3. To demonstrate compliance with general permit sections 5.2.1, the registrant shall maintain a copy of the site specific maintenance plan or manufacturer maintenance plan.

5.3.4. The registrant shall comply with all applicable recordkeeping requirements under NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

5.3.5. All records required by this section shall be maintained in accordance with section 3.5.1 of this general permit.

5.4. Testing Requirements

5.4.1. The registrant shall comply with all applicable testing requirements under NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

5.4.2. To demonstrate compliance with general permit section 5.1.5(a), the registrant shall verify that the closed-loop, automatic air/fuel ratio controller shall control a fuel metering valve to ensure a fuel-rich mixture and a resultant exhaust oxygen content of less than or equal to 2% during any performance testing.

5.5. Reporting Requirements

5.5.1. The registrant shall comply with all applicable notification requirements under NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

6.0. Source-Specific Requirements (Tanks)

6.1. Limitations and Standards

6.1.1. All tanks in the General Permit Registration application will be listed in Section 1.0 (the emission unit table) of the issued registration. Tanks are to be used for fuel storage for the emergency generators only.

6.2. Monitoring Requirements

6.2.1. See Facility-Wide Monitoring Requirements.

6.3. Testing Requirements

6.3.1. See Facility-Wide Testing Requirements.

6.4. Recordkeeping Requirements

6.4.1. See Facility-Wide Recordkeeping Requirements.

6.5. Reporting Requirements

6.5.1. See Facility-Wide Reporting Requirements.

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.

Attachment K
45 CSR 2/10 Monitoring Plan

45 CSR 2 and 45 CSR 10
Monitoring and Recordkeeping Plan

Mitchell Plant

<u>Facility Information:</u>

Facility Name: Mitchell Plant

Facility Address: P.O. Box K
State Route 2
Moundsville, WV 26041

Facility Environmental Contact: Mr. G. M. (Matt) Palmer
–Plant Environmental Coordinator

A. Facility Description:

Mitchell Plant is a coal-fired electric generating facility with two main combustion units (Units 1 and 2) discharging through a common stack shell that utilizes two separate stack discharge flues. Mitchell plant also has an auxiliary boiler (Aux. 1) that discharges through an independent auxiliary stack (aux 1). Unit 1, Unit 2, and Aux. Boiler 1 each have a design heat input greater than 10 mmBTU/hr making both 45 CSR 2A (Interpretive Rule for 45 CSR 2) and 45 CSR 10A (Interpretive Rule for 45 CSR 10) applicable to these sources.

I. 45 CSR 2 Monitoring Plan:

In accordance with Section 8.2.a of 45 CSR 2, following is the proposed plan for monitoring compliance with opacity limits found in Section 3 of that rule:

A. Main Stack (CS012)

1. Applicable Standard:

   45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method(s):

   45 CSR 2, §3.2 …*Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emissions control.*

45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

a. Primary Monitoring Method: While a Continuous Opacity Monitoring System (COMS) would not be required on a wet scrubbed fuel burning unit, Mitchell Plant has chosen to employ COMS on each of the fuel burning units upstream of the wet scrubbers and located in plant ductwork. As such, the primary method of monitoring opacity at Mitchell Plant will be Continuous Opacity Monitors (COMS). The COMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75.

b. Other Credible Monitoring Method(s): While Mitchell Plant will use COMS as the primary method of monitoring opacity of the fuel burning units, we are also reserving the right to use other appropriate method that would produce credible data. These "other monitoring methods" will generally be used in the absence of COMS data or as other credible evidence used in conjunction with COMS data.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned**

45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

The applicable paragraphs for Mitchell Plant are the following:

§7.1.a.2: *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

§7.1.a.4: *For fuel burning unit(s) which burn only coal, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a daily basis and an ash and BTU analysis for each shipment.*

§7.1.a.6: *For fuel burning unit(s) which burn a combination of fuels, the owner or operator shall comply with the applicable Recordkeeping requirements of paragraph 7.1.a.1 through 7.1.a.5 for each fuel burned.*

The date and time of each startup and shutdown of Units 1 and 2 will be maintained. The quantity of coal burned on a daily basis as well as the ash and Btu content will also be maintained. From a fuel oil perspective, the quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

b. **Record Maintenance**

45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.

4. Exception Reporting:

a. **Particulate Mass Emissions:**

45 CSR 2A, §7.2.a. *With respect to excursions associated with measured emissions under Section 4 of 45CSR2, compliance with the reporting and testing requirements under the Appendix to 45CSR2 shall fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45CSR2.*

Mitchell Plant will comply with the reporting and testing requirements specified under the Appendix to 45 CSR 2.

b. **Opacity:**

45 CSR 2A, §7.2.b. *COMS – In accordance with the provisions of this subdivision, each owner or operator employing COMS as the method of monitoring compliance with opacity limits shall submit a "COMS Summary Report" and/or an "Excursion and COMS Monitoring System Performance Report" to the Director on a quarterly basis; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the* *fuel burning unit(s). All reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter. The COMS Summary Report shall contain the information and be in the format shown in Appendix B unless otherwise specified by the Director.*

45 CSR 2A, §7.2.b.1. *If the total duration of excursions for the reporting period is less than one percent (1%) of the total operating time for the reporting period and monitoring system downtime for the reporting period is less than five percent (5%) of the total operating time for the reporting period, the COMS Summary Report shall be submitted to the Director; the Excursion and COMS Monitoring System Performance report shall be maintained on-site and shall be submitted to the Director upon request.*

45 CSR 2A, §7.2.b.2. *If the total duration of excursions for the reporting period is one percent (1%) or greater of the total operating time for the reporting period or the total monitoring system downtime for the reporting period is five percent (5%) or greater of the total operating time for the reporting period, the COMS Summary Report and the Excursion and COMS Monitoring System Performance Report shall both be submitted to the Director.*

45 CSR 2A, §7.2.b.3. *The Excursion and COMS Monitoring System Performance Report shall be in a format approved by the Director and shall include, but not be limited to, the following information:*

45 CSR 2A, §7.2.b.3.A. *The magnitude of each excursion, and the date and time, including starting and ending times, of each excursion.*

45 CSR 2A, §7.2.b.3.B. *Specific identification of each excursion that occurs during start-ups, shutdowns, and malfunctions of the facility.*

45 CSR 2A, §7.2.b.3.C. *The nature and cause of any excursion (if known), and the corrective action taken and preventative measures adopted (if any).*

45 CSR 2A, §7.2.b.3.D. *The date and time identifying each period during which quality- controlled monitoring data was unavailable, except for zero and span checks, and the reason for data unavailability and the nature of the repairs or adjustments to the monitoring system.*

45 CSR 2A, §7.2.b.3.E. *When no excursions have occurred or there were no periods of quality-controlled data unavailability, and no monitoring systems were inoperative, repaired, or adjusted, such information shall be stated in the report.*

Attached, as Appendices A and B are sample copies of a typical COMS "Summary Report" and "Excess opacity and COM downtime report" that we plan on using to fulfill the opacity reporting requirements. The COMS "Summary Report" will satisfy the conditions under 45 CSR 2A, §7.2.b for the "COMS Summary Report" and will be submitted to the Director according to its requirements. The "Excess opacity and COM downtime report" satisfies the conditions under 45 CSR 2A, §7.2.b.3. for the "Excursion and COMS Monitoring System Performance Report". The "Excess opacity and COM downtime report" shall be submitted to the Director following the conditions outlined in 45 CSR 2A, §7.2.b.1. and §7.2.b.2.

To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

B. **<u>Aux. Stack (aux 1)</u>**

1. Applicable Standard:

45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method:

45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

45 CSR 2, §8.4.a. *The owner or operator of a fuel burning unit(s) may petition for alternatives to testing, monitoring, and reporting requirements prescribed pursuant to this rule for conditions, including, but not limited to, the following:*

45 CSR 2, §8.4.a.1. *Infrequent use of a fuel burning unit(s)*

Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack. Based on limited operating hours, the requirement for COMS installation per Section 6.2.a of interpretive rule 45 CSR 2A was determined to be overly-burdensome and sufficient reason for the granting of alternative monitoring methods. The alternative monitoring method based on USEPA Method 9 visible emission readings is described below.

- Primary Monitoring Method: As an alternative to COMS monitoring, a Method 9 reading will be conducted one time per month provided the following conditions are met: 1) The auxiliary boiler has operated at normal, stable load conditions for at least 24 consecutive hours and 2) weather/lighting conditions are conducive to taking proper Method 9 readings. Since the Mitchell auxiliary boiler does not utilize post-combustion particulate emissions controls, operating parameters of control equipment are nonexistent and therefore unable to be monitored.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned**

45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

The applicable paragraph for the Mitchell Plant auxiliary boilers follows:

> **§7.1.a.2:** *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

As such, the date and time of each startup and shutdown of the auxiliary boiler will be maintained. The quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

b. **Record Maintenance**

45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. In the case of the auxiliary boilers, strip chart recordings, etc. are generally not available.

4. Exception Reporting:

Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack.

a. **Particulate Mass Emissions –** As an alternative to the testing and exception reporting requirements for particulate mass emissions from the auxiliary boiler, the following was previously proposed and approved. Based on an average heat content of approximately 139,877 Btu/gallon (calendar year 2000 data) and an AP-42 based particulate mass emissions emission factor of 2 lbs/thousand gallons, the calculated particulate mass emissions of the auxiliary boiler are 0.01 lb/mmBTU. As such, the fuel analysis records maintained under the fuel quality analysis and recordkeeping section of this plan provide sufficient evidence of compliance with the particulate mass emission limit. For the purpose of meeting exception reporting requirements, any fuel oil analysis indicating a heat content of less than 25,000 Btu per gallon will be reported to the OAQ to fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45 CSR 2 – 45 CSR 2A, §7.2.a. A heat content of 25,000 Btu/gal and a particulate emissions factor of 2 lbs/thousand gallons would result in a calculated particulate mass emissions of approximately 90% of the applicable 45 CSR 2 standard.

b. **Opacity –** As an alternative to the exception reporting requirements for opacity emissions from the auxiliary boiler, the following was previously proposed and approved. We will maintain a copy of each properly conducted (correct weather/lighting conditions, etc.) Method 9 evaluation performed. Any properly conducted Method 9 test which indicates an exceedance shall be submitted to the OAQ on a quarterly basis (within 30 days of the end of the quarter) along with an accompanying description of the excursion cause, any corrective action taken, and the beginning and ending times for the excursion.

   To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

If no exceptions have occurred during the quarter, then a report will be submitted to the OAQ stating so. This will identify periods in which no method 9 tests were conducted (e.g. unit out of service) or when no fuel oil was received.

II. <u>45 CSR 10 Monitoring Plan:</u>

In accordance with Section 8.2.c of 45 CSR 10, following is the proposed plan for monitoring compliance with the sulfur dioxide weight emission standards expressed in Section 3 of that rule:

A. Main Stack (CS012)

1. Applicable Standard:

   45 CSR 10, §3.1.b. *For fuel burning units of the Mitchell Plant of Ohio Power Company, located in Air Quality Control Region I, the product of 7.5 and the total actual operating heat inputs for such units discharging through those stacks in million BTU's per hour.*

   45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

   A new SO_2 limit will likely be established as a result of the installation of the flue gas desulfurization system/new stack configuration and the subsequent NAAQS compliance demonstration modeling. Assuming that revised SO2 limit is more stringent than the current limit expressed in 45 CSR 10, Mitchell Plant SO_2 emissions will be regulated by the more stringent of the two limits.

2. Monitoring Method:

   45 CSR 10, §8.2.c.1. *The installation, operation and maintenance of a continuous monitoring system meeting the requirements 40 CFR Part 60, Appendix B, Performance Specification 2 (PS2) or Performance Specification 7 (PS7) shall be deemed to fulfill the requirements of a monitoring plan for a fuel burning unit(s), manufacturing process source(s) or combustion source(s). CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS2.*

   a. Primary Monitoring Method: The primary method of monitoring SO_2 mass emissions from the two new stack flues (located within one stack shell) will be Continuous Emissions Monitors (CEMS). Data used in evaluating the performance of the Mitchell Units with the applicable standard will be unbiased, unsubstituted data as specified in definition 45 CSR 10A, §6.1.b.1. Data capture of more than 50% constitutes sufficient data for the daily mass emissions to be considered valid. The CEMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75. Because Units 1 and 2 will discharge through separate flues and both units are "Type a" fuel burning units as defined in 45 CSR 10, the plant-wide limit is calculated by summing the limits from the two flues.

   b. Other Credible Monitoring Method(s): While Mitchell Plant will use CEMS as the primary method of monitoring SO_2 mass emissions from the two flues, we are also reserving the right to use other appropriate methods that would produce credible data. These "other monitoring methods" will generally be used in the absence of CEMS data or as other credible evidence used in conjunction with CEMS data.

3. Recordkeeping:

   a. **Operating Schedule and Quality/Quantity of Fuel Burned:**

      45 CSR 10A, §7.1.a. *Fuel burning units - The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule and the quality or quantity of fuel burned in each unit…*

      45 CSR 10A, §7.1.c. *The owner or operator of a fuel burning unit or combustion source which utilizes CEMS shall be exempt from the provisions of subdivision 7.1.a. or 7.1.b, respectively.*

      As such, Mitchell plant will not maintain records of the operating schedule and the quality and quantity of fuel burned in each unit for purposes of meeting the requirements for a monitoring plan under 45 CSR 10. While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

   b. **Record Maintenance**

      45 CSR 10A, §7.1.d. *For fuel burning units, manufacturing process sources, and combustion sources, records of all required monitoring data as established in an approved monitoring plan and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

      As such, CEMS records at Mitchell Plant will be maintained for at least five years.

4. Exception Reporting:

   45 CSR 10A, §7.2.a. *CEMS - Each owner or operator employing CEMS for an approved monitoring plan, shall submit a "CEMS Summary Report" and/or a "CEMS Excursion and Monitoring System Performance Report" to the Director quarterly; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the source. All reports shall be postmarked no later than forty-five (45) days following the end of each calendar quarter. The CEMS Summary Report shall contain the information and be in the format shown in Appendix A unless otherwise specified by the Director.*

45 CSR 10A, §7.2.a.1. *Submittal of 40 CFR Part 75 data in electronic data (EDR) format to the Director shall be deemed to satisfy the requirements of subdivision 7.2.a.*

As such, Mitchell Plant will submit the 40 CFR 75 quarterly electronic data reports (EDRs) to the OAQ to meet the requirements for a CEMS Summary Report and the CEMS Excursion and Monitoring System Performance Report. The EDR reports will be submitted to the OAQ no later than 45 days following the end of the quarter.

When no excursions of the 24-hour SO_2 standard have occurred, such information shall be stated in the cover letter of the EDR submittal.

B. Aux. Stack (aux 1)

1. Applicable Standard:

45 CSR 10, §3.1.e. *For type 'b' and Type 'c' fuel burning units, the product of 3.1 and the total design heat inputs for such units discharging through those stacks in million BTU's per hour.*

45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

2. Monitoring, Recordkeeping, Exception Reporting Requirements:

45 CSR 10, §10.3. *The owner or operator of a fuel burning unit(s) which combusts natural gas, wood or distillate oil, alone or in combination, shall be exempt from the requirements of section 8.*

As such, the Mitchell Plant auxiliary boiler (auxiliary stack) is exempt from Testing, Monitoring, Recordkeeping, and Reporting requirements found in 45 CSR 10, Section 8 because the fuel burning source combusts only distillate oil. 45 CSR 10, Section 8 also contains the requirement for the development of a monitoring plan. The simple nature of burning distillate oil results in an SO2 emission rate well below the standard.

While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

Revisions of Monitoring Plan:

Mitchell Plant reserves the right to periodically revise the conditions of this monitoring plan. Any revised plan will become effective only after approval by the OAQ.

Implementation of Revised Monitoring Plan:

Implementation of this revised monitoring plan will occur in concurrence with the installation and operation of the new stack for Units 1 and 2 at Mitchell Plant.

Attachment L
Suggested Title V Permit Language

Wheeling Power suggests that the following changes be made to the Title V Permit Equipment Table to reflect recent additions, not impacting Title V permit language.

Emission Point ID[1]	Control Device[1]	Emission Unit ID[1]	Emission Unit Description	Design Capacity	Year Installed/ Modified
Tank #64	N/A	Tank #64	Bioreactor Nutrient Tank	12,575 Gal.	2024
Tank #65	N/A	Tank #65	Bioreactor Hydrochloric Acid Tank	6,000 Gal.	2024
Tank #66	N/A	Tank #66	WW Pond Sulfuric Acid Tank	14,500 Gal.	2023
Tank #67	N/A	Tank #67	WW Pond Sodium Hydroxide Tank	20,300 Gal.	2023
Tank #68	N/A	Tank #68	WW Pond Organosulfide Tank	6,400 Gal.	2023
Tank #69	N/A	Tank #69	WW Pond Polymer Tank	1,360 Gal.	2023

Wheeling Power suggests the following administrative revisions to the Title V permit that will improve the functionality of the permit for plant staff.

4.0 Main Boilers [Em. Unit IDs *Unit 1* and *Unit 2* – Em. Pt. IDs *1E* and *2E*]

Permit Condition 4.1.4.a: Historically, Mitchell Plant has conducted particulate matter compliance testing on both units (Unit 1 & Unit 2) during the same 7 day operational period, per the 7 day requirement listed in 45CSR2-Appendix §§ 4.1.b. Due to unit availability, scheduling and performing these tests on both units within the same 7 day period can be difficult at times, and neither 45CSR2-Appendix §§ 4.1.b. or the Title V permit specifies an individual or combined unit testing requirement within the same 7 day period. Wheeling Power is suggesting that additional language be added to this section clarifying if both units have to be tested within the same 7 day period, or if each unit has its own 7 day testing period.

6.0 Material Handling [Emission point IDs identified in Equipment Table subsection 1.1.]

Permit Condition 6.1.13: Polymer and organosulfide for the FGD wastewater treatment facility delivered to the facility via paved roadway(s) has an existing maximum annual rate of 13,500 gallons per year. Wheeling Power requests that this maximum annual rate be increased to 25,000 gallons per year to simplify the ordering and delivery process for plant staff and vendor(s).

Wheeling Power suggests the following language revisions to the Title V permit associated with the Unit 1 and Unit 2 Emergency Diesel Driven Fire Pump replacements.

7.0 Emergency Quench Water Pump Diesel-fired Engines [emission unit IDs: 6S, 7S; emission point IDs: 15E, 16E] and Emergency Diesel-Driven Fire Pumps [emission unit IDs: 17S, 18S; emission point IDs: 17E, 18E]

Sections 7.1, 7.4, and 7.5: The previous emergency diesel driven fire pump engines (17S, 18S) were subject to the requirements in 40 CFR 63 Subpart ZZZZ, and the new replacement diesel driven fire pump engines are subject to 40 CFR 63 Subpart IIII. Suggested language referring to these requirements is provided in Attachment S of this Title V Renewal Application, as Attachment I in the Minor Modification package associated with fire pump engine 18S (the Minor Modification application associated with fire pump engine 17S was previously submitted on 8/25/2023).

Attachment S
Title V Permit Revision Application

	WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION **DIVISION OF AIR QUALITY** **601 57th Street, SE** **Charleston, WV 25304** **(304) 926-0475** www.dep.wv.gov/daq

TITLE V PERMIT REVISION APPLICATION

PLEASE CHECK TYPE OF TITLE V PERMIT REVISION:	**TITLE V PERMIT NUMBER:**
☐ **ADMINISTRATIVE AMENDMENT** ☑ **MINOR MODIFICATION** ☐ **SIGNIFICANT MODIFICATION** ☐ **OFF-PERMIT CHANGE** ☐ **OPERATIONAL FLEXIBILITY [502(B)(10) CHANGES]** ☐ **REOPENING**	**R30-** 05100005-2019 (MM01) **WHEN DID OR WHEN WILL THE CHANGES OCCUR?** MM/DD/YYYY : 06/2024 **SIC CODES: PRIMARY:** 4911 **SECONDARY:**

Refer to "Title V Revision Guidance" (Appendix A, "Title V Permit Revision Flowchart"), for type of revision, and to Section 7 of this Application for Application Completeness and Ability to Operate information

Section 1: General Information

a. Name of Applicant ***(As registered with the WV Secretary of State's Office)***:	**b. Facility Name or Location:**
Wheeling Power Company	Mitchell Plant

b. Contact Information		
Responsible Official: Joshua D. Snodgrass		Title: Plant Manager
Street or P.O. Box: P.O. Box K		
City: Moundsville	State: WV	Zip:
Telephone Number: (304) 843 - 6005	Fax Number: (304) 843 - 6080	E-mail: jdsnodgrass@aep.com
Environmental Contact: G. M. (Matt) Palmer		Title: Plant Environmental Coordinator
Street or P.O. Box: P.O. Box K		
City: Moundsville	State: WV	Zip: 26041
Telephone Number: (304) 843 - 6048	Fax Number: (304) 843 - 6080	E-mail: gmpalmer@aep.com
Application Preparer: Brandon T. Belcher		Title: Environmental Specialist
Company: AEP Service Corp.		
Street or P.O. Box: 1 Riverside Plaza, 21st Floor		
City: Columbus	State: OH	Zip: 43215
Telephone Number: (304) 541 - 7437	Fax Number: ( ) -	E-mail: btbelcher@aep.com
Person to contact if we have questions regarding this Application: Brandon T. Belcher		
All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.		

Section 2: Revision Information

a. Description of Changes Associated with this Permit Revision

Provide a general description of changes to the facility.

This change involves the replacement of an emergency diesel driven fire pump and fuel tank associated with Unit 2 at the Mitchell Plant. The new diesel driven fire pump is identical to the one installed in 2023 for Unit 1.

b. Business Confidentiality Claims

Does this application include confidential information (per 45CSR31)? ☐ Yes ☑ No

If Yes, identify each segment of information on each page that is submitted as confidential, and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's ***"PRECAUTIONARY NOTICE-CLAIMS OF CONFIDENTIALITY"*** guidance as **ATTACHMENT A.**

c. Provide a **Plot Plan(s**) if new emission points were added since latest revision, e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the new/modified stationary source(s) is located as **ATTACHMENT B.** For instructions, refer to "***Plot Plan - Guidelines***"**.**

d. Provide a detailed **Process Flow Diagram(s)** if new emission points were added since latest revision, showing each new/modified process or emissions unit as **ATTACHMENT C.** Process Flow Diagrams should show all emission units, control equipment, emission points, and their relationships.

e. Emission Units Table

Fill out the **Emission Units Table** for new and/or modified equipment and provide it as **ATTACHMENT D**.

f. Emission Units Form(s)

For each new and/or modified emission unit(s) with applicable requirement(s) listed in the **Emission Units Table**, fill out and provide an **Emission Unit Form(s)** as **ATTACHMENT E**.

Are you in compliance with all facility-wide applicable requirements? ☑ Yes ☐ No

For each new and/or modified emission unit not in compliance with an applicable requirement, fill out a **Schedule of Compliance Form** as **ATTACHMENT F**.

g. Control Devices

For each new and/or modified control device listed in the **Emission Units Table**, fill out and provide an **Air Pollution Control Device Form(s)** as **ATTACHMENT G**.

For any control device that is required on an emission unit in order to meet a standard or limitation for which the potential pre-control device emissions of an applicable regulated air pollutant is greater than or equal to the Part 70 Major Source Threshold level, refer to the **Compliance Assurance Monitoring (CAM) Form(s)** for CAM applicability. If applicable, please check appropriate box in Section 3(a) below, fill out and provide these forms for each Pollutant Specific Emission Unit (PSEU) as **ATTACHMENT H**.

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Section 3: New Applicable Requirements

a. New Applicable Requirements Summary	
Mark all applicable requirements associated with the changes involved with this permit revision:	
☐ SIP	☐ FIP
☐ Minor source NSR (45CSR13)	☐ PSD (45CSR14)
☐ NESHAP (45CSR34)	☐ Nonattainment NSR (45CSR19)
☑ Section 111 NSPS (Subpart(s) IIII)	☑ Section 112(d) MACT standards (Subpart(s) ZZZZ)
☐ Section 112(g) Case-by-case MACT	☐ 112(r) RMP
☐ Section 112(i) Early reduction of HAP	☐ Consumer/commercial prod. reqts., section 183(e)
☐ Section 129 Standards/Reqts.	☐ Stratospheric ozone (Title VI)
☐ Tank vessel reqt., section 183(f)	☐ Emissions cap 45CSR§30-2.6.1
☐ NAAQS, increments or visibility (temp. sources)	☐ 45CSR27 State enforceable only rule
☐ 45CSR4 State enforceable only rule	☐ Acid Rain (Title IV, 45CSR33)
☐ Emissions Trading and Banking (45CSR28)	☐ Compliance Assurance Monitoring (40CFR64)
☐ CAIR NO_x Annual Trading Program (45CSR39)	☐ CAIR NO_x Ozone Season Trading Program (45CSR26)
☐ CAIR SO_2 Trading Program (45CSR41)	

b. Non Applicability Determinations

List all requirements, which the source has determined not applicable to this permit revision and for which a permit shield is requested. The listing shall also include the rule citation and a rationale for the determination.

N/A

☐ **Permit Shield Requested** *(not applicable to Minor Modifications, Off-Permit Changes, or for Operational Flexibility)*

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

c. Suggested Title V Draft Permit Language
Provide **Suggested Title V Draft Permit language** for the proposed Title V Permit revision (including all applicable requirements associated with the permit revision and any associated monitoring /recordkeeping/ reporting requirements), OR attach a marked up pages of current Title V Permit as **ATTACHMENT I**. Please include appropriate citations (Permit or Consent Order number, condition number and/or rule citation (e. g. 45CSR§7-4.1)) for those requirements being added / revised.
See Attachment I

d. Active NSR Permits/Permit Determinations/Consent Orders Associated With This Permit Revision

Permit or Consent Order Number	Date of Issuance (MM/DD/YYYY)	Permit/Consent Order Condition Number
Installation did not trigger Reg 13 modification thresholds		

e. Inactive NSR Permits/Obsolete Permit or Consent Orders Conditions Associated With This Revision

Permit Number	Date of Issuance (MM/DD/YYYY)	Permit/Consent Order Condition Number

Section 4: Change in Potential Emissions

Pollutant	Change in Potential Emissions (+ or -), TPY	For Off-Permit Changes: Provide Total Aggregated Emissions Increase Since Last Permit/Modification
NOx	0.34	Note: The estimated emissions
CO	0.16	listed do not take into account the
NMHC	0.009	reduction in emissions related to
SO2	0.128	the replacement of the original fire
Particulate Matter	0.015	pump engine.

Provide **Supporting Emission Calculations/Estimations** as **ATTACHMENT J**.

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Section 5: Certification of Information

a. Certification For Use Of Minor Modification Procedures ***(Required Only for Minor Modification Requests)***	
Note:	*This certification must be signed by a responsible official. Applications without a signed certification will be returned as incomplete. The criteria for allowing the use of Minor Modification Procedures are as follows:*

i. Proposed changes do not violate any applicable requirement;

ii. Proposed changes do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

iii. Proposed changes do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient air quality impacts, or a visibility increment analysis;

iv. Proposed changes do not seek to establish or change a permit term or condition for which there is no underlying applicable requirement and which permit or condition has been used to avoid an applicable requirement to which the source would otherwise be subject (synthetic minor). Such terms and conditions include, but are not limited to a federally enforceable emissions cap used to avoid classification as a modification under any provision of Title I or any alternative emissions limit approved pursuant to regulations promulgated under § 112(j)(5) of the Clean Air Act;

v. Proposed changes do not involve preconstruction review under Title I of the Clean Air Act or 45CSR14 and 45CSR19;

vi. Proposed changes are not required under any rule of the Director to be processed as a significant modification;

Notwithstanding subparagraph 45CSR§30-6.5.a.1.A. (items i through vi above), minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in rules of the Director which are approved by the U.S. EPA as a part of the State Implementation Plan under the Clean Air Act, or which may be otherwise provided for in the Title V operating permit issued under 45CSR30.

Pursuant to 45CSR§30-6.5.a.2.C., the proposed modification contained herein meets the criteria for use of Minor permit modification procedures as set forth in Section 45CSR§30-6.5.a.1.A. The use of Minor permit modification procedures are hereby requested for processing of this application.

(Signed):	[signature] *(Please use blue ink)*	Date:	5 / 9 / 24 *(Please use blue ink)*
Named (typed):	Joshua D. Snodgrass	Title:	Plant Manager

b. **Certification of Truth, Accuracy and Completeness and Certification of Compliance** ***(Required For All Revision Requests)***

Note:	*This Certification must be signed by a responsible official. Applications without a signed certification will be returned as incomplete.*

Certification of Truth, Accuracy and Completeness

I certify that I am a responsible official (as defined at 45CSR§30-2.38) and am accordingly authorized to make this submission on behalf of the owners or operators of the source described in this document and its attachments. I certify under penalty of law that I have personally examined and am familiar with the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine and/or imprisonment.

Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

Responsible official (type or print)

Name: Joshua D. Snodgrass	Title: Plant Manager

Responsible official's signature:

Signature: ______________ *(Please use blue ink)* Signature Date: 5/9/24 *(Please use blue ink)*

Section 6: Attachments

Note: Please check all applicable attachments included with this permit application:	
☐	ATTACHMENT A: Business Confidentiality Claims
☑	ATTACHMENT B: Plot Plan(s)
☑	ATTACHMENT C: Process Flow Diagram(s)
☑	ATTACHMENT D: Emission Units Table
☑	ATTACHMENT E: Emission Unit Form(s)
☐	ATTACHMENT F: Schedule of Compliance Form(s)
☐	ATTACHMENT G: Air Pollution Control Device Form(s)
☐	ATTACHMENT H: Compliance Assurance Monitoring Form(s)
☑	ATTACHMENT I: Suggested Title V Draft Permit Language
☑	ATTACHMENT J: Supporting Emission Calculations/Estimations

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

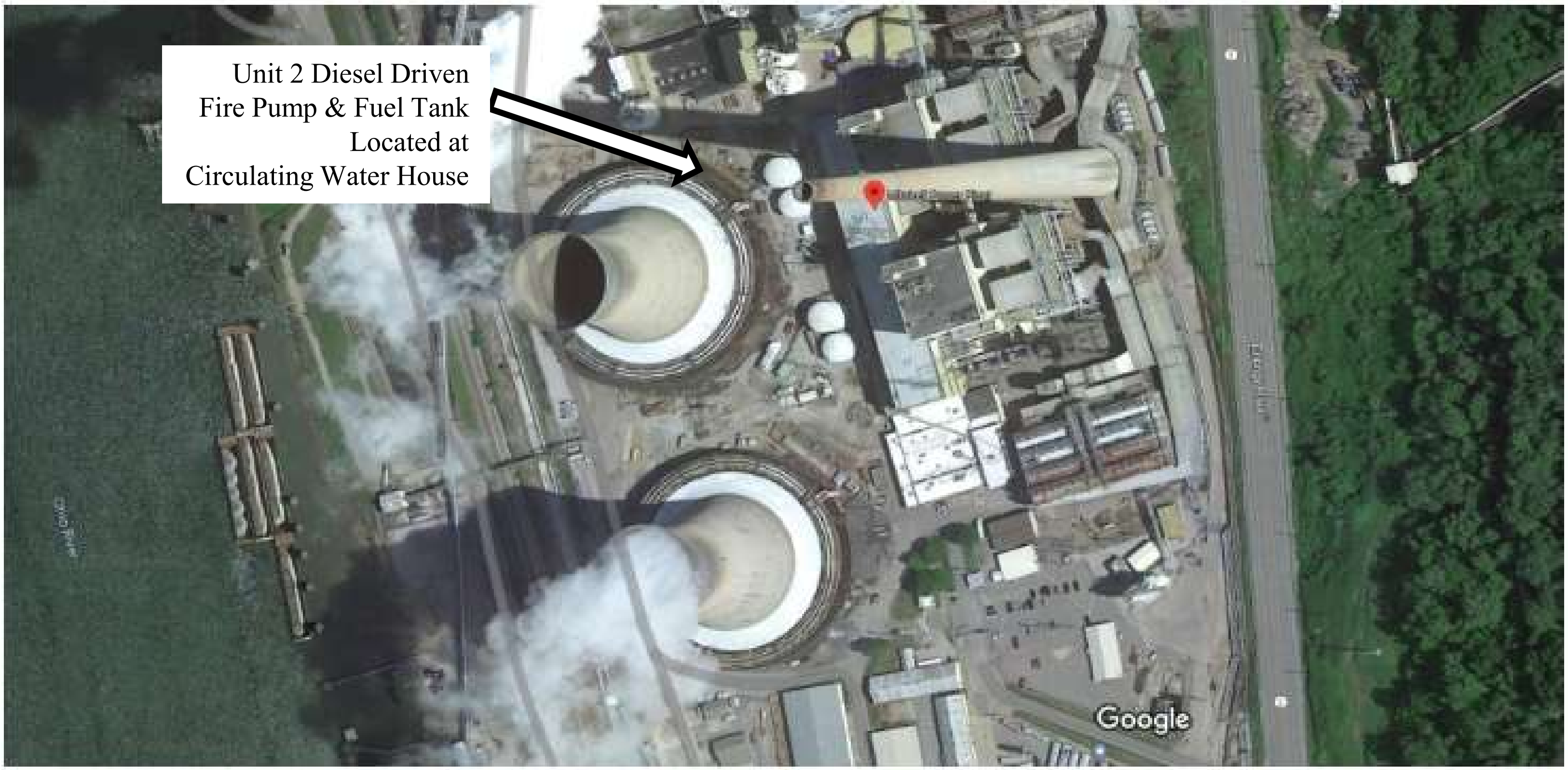
Section 7: Application Completeness and Ability to Operate information for different types of Title V Permit revisions

(Refer to "Title V Revision Guidance" for more information)

Type of Revision	Application/Notification Requirements	Ability to Operate
Administrative Amendment	☐ Description of change ☐ Supplemental information (rationale) ☐ Certification of application and compliance (Section 5(b))	Upon submittal of the application
Minor Modification	☑ Description of change ☑ Associated change in emissions ☑ Sample Calculations/estimations for determining emissions ☑ List of new applicable requirements associated with changes ☑ List of R13/R14 permits associated with the changes ☑ Suggested draft permit language ☑ Certification for use of Minor Modification (Section 5(a)) ☑ Certification of application and compliance (Section 5(b)) ***No Permit Shield***	After seven (7) days from the submittal of the application, or upon issuance of the R13/R14 permit (if any), whichever is later
Significant Modification	☐ Description of change ☐ Associated change in emissions ☐ Sample Calculations/estimations for determining emissions ☐ List of R13/R14 permits associated with the changes ☐ List of new applicable requirements associated with changes ☐ Request for permit shield ☐ Updated drawings, plot plans, process flow diagrams, etc. ☐ Certification of application and compliance (Section 5(b))	Upon issuance of the modified Title V permit (if changes either conflict with, or are prohibited by existing Title V Permit terms/ conditions), OR upon obtaining of proper R13/ R14 Permit for first 12 months (if changes neither conflict with, nor are prohibited by existing Title V Permit terms/conditions)
Off-Permit Changes	☐ Notification/application to DAQ and U.S.E.P.A. within 2 business days of the change ☐ Description of the change ☐ The date on which the change will occur or has occurred ☐ Pollutants and amounts emitted ☐ Sample Calculations/estimations for determining emissions ☐ Any new applicable requirements that will apply to changes ☐ Certification of application and compliance (Section 5(b)) ***No Permit Shield***	After two (2) days from the submittal of the application
Operational Flexibility	☐ Notification/application submitted to DAQ and U.S.E.P.A. in advance (7 days prior to making changes) ☐ Description of the change ☐ The date on which the change is to occur ☐ Permit terms and conditions affected by the change ☐ Certification of application and compliance (Section 5(b)) ***No Permit Shield***	After seven (7) days from the submittal of the application/notification to DAQ and EPA
Reopening	☐ Description of change ☐ List of new applicable requirements associated with changes ☐ Suggested draft permit language ☐ Certification of application and compliance (Section 5(b))	Ability to operate is not reflected by the changes

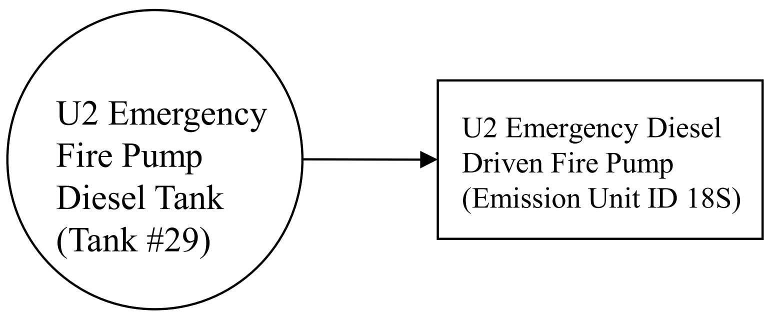
All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Attachment B: Mitchell Plant



Imagery ©2023 Airbus, Maxar Technologies, USDA/FPAC/GEO, Map data ©2023 100 ft

Attachment C:
Mitchell Plant Unit 2 Emergency Diesel Driven Fire Pump



ATTACHMENT D - Title V Equipment Table
(includes all emission units at the facility except those designated as insignificant activities in Section 4, Item 24 of the General Forms)

Emission Unit ID[1]	Emission Point ID[1]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Control Device[1]
18S	18E	Unit 2 Emergency Diesel Driven Fire Pump	2024	249 BHP	
Tank #29	Tank #29	Diesel Fire Pump Fuel Tank - U2	2024	300 gal	

[1]For 45CSR13 permitted sources, the numbering system used for the emission points, control devices, and emission units should be consistent with the numbering system used in the 45CSR13 permit. For grandfathered sources, the numbering system should be consistent with registrations or emissions inventory previously submitted to DAQ. For emission points, control devices, and emissions units which have not been previously labeled, use the following 45CSR13 numbering system: 1S, 2S, 3S,... or other appropriate description for emission units; 1C, 2C, 3C,... or other appropriate designation for control devices; 1E, 2E, 3E, ... or other appropriate designation for emission points.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	Emission unit name:	List any control devices associated with this emission unit:
18S	Unit 2 Emergency Diesel Driven Fire Pump	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Emergency diesel driven fire pump that will replace existing unit associated with Unit 2 at the plant. 249 BHP diesel engine.

Manufacturer:	Model number:	Serial number:
Cummins	CFP7E-F60 Fire Pump / QSB6.7 Engine	
Construction date: MM/DD/YYYY 06/2024	**Installation date:** MM/DD/YYYY 06/2024	**Modification date(s):** MM/DD/YYYY 06/2024

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Approx. 14 gal/hr, 249 BHP

Maximum Hourly Throughput:	Maximum Annual Throughput:	Maximum Operating Schedule:
Approx. 14 gal/hr	7,000 gal/yr	Assumed 500 hr/yr, but not limited during emergency

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No	If yes, is it? ☐ Indirect Fired ☑ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 249 BHP	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15 ppm sulfur.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		Approx. 137,030 btu/gal

Page 1 of 3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.65	0.16
Nitrogen Oxides (NO_X)	1.36	0.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.06	0.015
Particulate Matter (PM_{10})	0.06	0.015
Total Particulate Matter (TSP)	0.06	0.015
Sulfur Dioxide (SO_2)	0.51	0.128
Volatile Organic Compounds (VOC)	0.63	0.16
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY
CO2	286.35	71.59

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, PM, and CO. AP-42 used for SO2, CO2, and VOC.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L.

Requirements currently captured in Title V permit:
R30-05100005-2019 (MM01) Section 7.1.

☐ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L.

Requirements currently captured in Title V permit:
R30-05100005-2019 (MM01) Sections 7.2 through 7.5.

Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Attachment I

Summary of Requirements[1]

40 CFR part 60, subpart IIII

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

For fire pump engines with a displacement of less than 30 liters/cyl, manufactured during or after the model year that applies to your fire pump engine power rating in Table 3 of 40 CFR part 60, subpart IIII.

NOTE: To refer directly to the regulatory text, please go to Subpart IIII (scroll down to almost the end of the page).

Temporary Engines:

Per 60.4200(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

Emission Standards: 60.4205(c), Table 4

60.4205(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

Per 60.4215(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205. Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the emission standards in 60.4215(c).

Special requirements apply to engines used in Alaska. Please refer to 60.4216 for the specific requirements and provisions that apply to engines that are located in areas of Alaska not accessible by the FAHS.

[1]Disclaimer: The content provided in this software tool is intended solely as assistance for potential reporters to aid in assessing requirements for compliance under the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60 Subpart IIII. Any variation between the rule and the information provided in this tool is unintentional, and, in the case of such variations, the requirements of the rule govern. Use of this tool does not constitute an assessment by EPA of the applicability of the rule to any particular facility. In any particular case, EPA will make its assessment by applying the law and regulations to the specific facts of the case.

Fuel Requirements: 60.4207(a), (b), (e)

60.4207(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Per 60.4215(b) stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in 40 CFR 60.4207.

Special requirements apply to engines used in Alaska. Please refer to 60.4216 for the specific requirements and provisions that apply to engines that are located in areas of Alaska not accessible by the FAHS.

Per 60.4217 Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

Importing/Installing Requirements: 60.4208(h), (i)

60.4208(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

Monitoring Requirements: 60.4209(a); If your engine is equipped with a diesel particulate filter: 60.4209(b)

60.4209(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

If your engine is equipped with a diesel particulate filter: 60.4209(b)

60.4209 (b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements: 60.4206, 60.4211(a), (c), (f), (g)

60.4206 Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

60.4211(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(f) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

Testing Requirements: 60.4212

60.4212 Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

Notification, Reports, and Records Requirements: 60.4214(b); If equipped with DPF: 60.4214(c); If >100 HP and > 15 hrs/yr for emergency DR: 60.4214(d)

60.4214(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in Table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

If your engine is equipped with a diesel particulate filter: 60.4214(c)

60.4214(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

If your engine is greater than 100 HP and used more than 15 hours a year for emergency demand response:

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

General Provisions (40 CFR part 60): Table 8

Attachment J:

Cummins QSB6.7 Emergency Diesel Driven Fire Pump Emission Calculations

Max Power	249 BHP		
Fuel Use:	14 gal/hr	1.92	MMBtu/hr
	7,000 gal/yr assuming 500 hours operation.	959.21	MMBtu/yr
	137,030 Btu/gal (diesel heat content)		

Hourly Emissions:

	Emission Factor*	Emissions	Emissions	Note:
	Grams/kWh	lb/hr	lb/24hr	
NOx	2.475 Grams/bhp-hr	1.36	32.61	
CO	1.193 Grams/bhp-hr	0.65	15.72	
NMHC	0.062 Grams/bhp-hr	0.03	0.82	* NOx, CO, and NMHC EF's based on Cummins QSB6.7 Spec Sheet.
SO2	0.00205 lb/HP-hr	0.51	12.25	* SO2 estimated using Chapter 3.3 of AP-42 for diesel industrial engines.
PM=PM10=PM2.5	0.111 Grams/bhp-hr	0.06	1.46	* All PM assumed to be less than 1 um
CO2	1.15 lb/HP-hr	286.35	6872.40	* CO2 estimated using AP-42 CO2 EF for diesel industrial engines.
VOC (used TOC)	0.0025141 lb/HP-hr	0.63	15.02	*TOC estimated using AP-42 TOC EF's for exhaust and crankcase emissions for diesel industrial engines.
Formaldehyde	0.00118 lb/MMBtu	0.00226	0.0543	* Formaldehyde estimated using AP-42 Formaldehyde EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Benzene	0.000933 lb/MMBtu	0.0018	0.043	* Benzene estimated using AP-42 Benzene EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Propylene	0.00258 lb/MMBtu	0.005	0.12	* Propylene estimated using AP-42 1,3 Butadiene EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Toluene	0.000409 lb/MMBtu	0.0008	0.019	* Toluene estimated using AP-42 Toluene EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Xylenes	0.000285 lb/MMBtu	0.00055	0.013	* Xylenes estimated using AP-42 Xylenes EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).

Acetaldehyde	0.000767 lb/MMBtu	0.00147	0.0353	*Acetaldehyde estimated using AP-42 Acetaldehyde EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Acrolein	0.0000925 lb/MMBtu	0.000177	0.00426	*Acrolein estimated using AP-42 Acrolein EF for diesel industrial engines. Assuming 1.4gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Napthalene	0.0000848lb/MMBtu	0.00016	0.004	*Naphthalene estimated using AP-42 Naphthalene EF for diesel industrial engines. Assuming 1.9 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Total HAPS		0.007	0.17	

Typical Annual Emissions - **(Assume 500 hrs/yr)**

	Emissions
	tons/yr
NOx	0.34
CO	0.16
HC	0.009
SO2	0.1276
PM	0.015
CO2	71.59
VOC	0.16
Formaldehyde	0.000566
Benzene	0.00045
Propylene	0.0012
Toluene	0.00020
Xylenes	0.00014
Acetaldehyde	0.000368
Acrolein	0.0000444
Napthalene	0.00004
Total HAPS	0.0028

Division of Air Quality Permit Application Submittal

Please find attached a permit application for : Wheeling Power Company; Mitchell Plant

[Company Name; Facility Location]

- DAQ Facility ID (for existing facilities only): 03-054-05100005
- Current 45CSR13 and 45CSR30 (Title V) permits associated with this process (for existing facilities only): R30-05100005-2019 (MM01)

- Type of NSR Application (check all that apply):
  - ☐ Construction
  - ☐ Modification
  - ☐ Class I Administrative Update
  - ☐ Class II Administrative Update
  - ☐ Relocation
  - ☐ Temporary
  - ☐ Permit Determination

- Type of 45CSR30 (TITLE V) Application:
  - ☐ Title V Initial
  - ☑ Title V Renewal
  - ☐ Administrative Amendment**
  - ☑ Minor Modification**
  - ☐ Significant Modification**
  - ☐ Off Permit Change

****If the box above is checked, include the Title V revision information as ATTACHMENT S to the combined NSR/Title V application.**

- Payment Type:
  - ☐ Credit Card (Instructions to pay by credit card will be sent in the Application Status email.)
  - ☑ Check (Make checks payable to: WVDEP – Division of Air Quality)

    Mail checks to:
    WVDEP – DAQ – Permitting
    Attn: NSR Permitting Secretary
    601 57th Street, SE
    Charleston, WV 25304

Please wait until DAQ emails you the Facility ID Number and Permit Application Number. Please add these identifiers to your check or cover letter with your check.

- If the permit writer has any questions, please contact (all that apply):
  - ☐ Responsible Official/Authorized Representative
    - Name: Joshua D. Snodgrass
    - Email: jdsnodgrass@aep.com
    - Phone Number: 304-843-6005
  - ☑ Company Contact
    - Name: G. M.(Matt) Palmer
    - Email: gmpalmer@aep.com
    - Phone Number: 304-843-6048
  - ☑ Consultant
    - Name: Brandon T. Belcher
    - Email: btbelcher@aep.com
    - Phone Number: 304-541-7437

Roberts, Daniel P <daniel.p.roberts@wv.gov>

Fwd: [Wheeling Power Company; Mitchell Plant] Title V Permit Renewal Application
1 message

Air Quality Permitting, DEP <depairqualitypermitting@wv.gov> Thu, May 9, 2024 at 3:38 PM
To: Stephanie R Mink <stephanie.r.mink@wv.gov>
Cc: Daniel P Roberts <daniel.p.roberts@wv.gov>

Stephanie,

Please assign this renewal to Dan as R30-05100005-2024.

Thanks,
Carrie
---------- Forwarded message ---------
From: **Brandon T Belcher** <btbelcher@aep.com>
Date: Thu, May 9, 2024 at 10:09 AM
Subject: [Wheeling Power Company; Mitchell Plant] Title V Permit Renewal Application
To: DEPAirQualityPermitting@wv.gov <DEPAirQualityPermitting@wv.gov>
Cc: Joshua D Snodgrass <jdsnodgrass@aep.com>, G M Palmer <gmpalmer@aep.com>, Danielle R Roski <drroski@aep.com>, Tim Lohner <twlohner@aep.com>

Dear Ms. Crowder,

In accordance with Condition 2.3 for the subject permit, enclosed is an electronic copy of a signed Title V Permit Renewal Application for Wheeling Power Company's Mitchell Plant. The subject application is for the Steam Electric Generating Facility located near Moundsville, WV in Marshall County. The existing permit expires on November 26, 2024. A completed DAQ email cover letter for this application submittal is also enclosed.

Should you have any questions, please let me know.

Sincerely,

Brandon

AMERICAN ELECTRIC POWER
BRANDON T BELCHER | ENVIRONMENTAL SPECIALIST SR
BTBELCHER@AEP.COM | A:8.200.1800 | C:304.541.7437
1 RIVERSIDE PLAZA, COLUMBUS, OH 43215

2 attachments

Email Cover Letter-ML Title V Permit Renewal 2024_final.pdf
553K

Final - Title V Renewal Permit Application 20240509.pdf
20897K

American Electric Power
1 Riverside Plaza
Columbus, OH 43215
aep.com

May 9, 2024

Ms. Laura M. Crowder, Director (electronically via DEPAirQualityPermitting@wv.gov)
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, West Virginia 25304

RE: 45 CSR 30 Permit Renewal Application
Plant ID# 051-00005

Dear Ms. Crowder:

In accordance with Condition 2.3 for the subject permit, enclosed is an electronic copy (via email) of a signed Title V Permit Renewal Application for Wheeling Power Company's Mitchell Plant. The subject application is for the Steam Electric Generating Facility located near Moundsville, WV in Marshall County. The existing permit expires on November 26, 2024.

Please contact Brandon T. Belcher at (304) 541-7437 or G. M. (Matt) Palmer at (304) 843-6048 if you have any questions.

Sincerely,

Joshua D. Snodgrass
Plant Manager, Mitchell Plant

Re: 45 CSR 30 Permit Renewal Application
Plant ID# 051-00005

ec: T. W. Lohner / B. T. Belcher — Environmental Services
G. M. Palmer / D. R. Roski — Mitchell Plant

Enclosure: Mitchell Plant Title V Renewal Application Package

Wheeling Power Company
Mitchell Plant

Title V Permit Renewal Application
R30-05100005-2019 (MM01)

Prepared For:

Wheeling Power Company
Mitchell Plant
Moundsville, West Virginia

Prepared By:

American Electric Power
Environmental Services
1 Riverside Plaza
Columbus, Ohio 43215
May 2024

Wheeling Power Company
Mitchell Plant

Regulation 30 Permit Renewal Application

Table of Contents

WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY
601 57th Street SE
Charleston, WV 25304
Phone: (304) 926-0475
www.dep.wv.gov/daq

INITIAL/RENEWAL TITLE V PERMIT APPLICATION - GENERAL FORMS

Section 1: General Information

1. **Name of Applicant (As registered with the WV Secretary of State's Office):** Wheeling Power Company	**2. Facility Name or Location:** Mitchell Plant
3. DAQ Plant ID No.: 051-00005	**4. Federal Employer ID No. (FEIN):** 610247775

5. **Permit Application Type:**

- ☐ Initial Permit — When did operations commence? 1970
- ☑ Permit Renewal — What is the expiration date of the existing permit? 11/26/2024
- ☐ Update to Initial/Renewal Permit Application

6. Type of Business Entity: ☑ Corporation ☐ Governmental Agency ☐ LLC ☐ Partnership ☐ Limited Partnership	**7. Is the Applicant the:** ☐ Owner ☐ Operator ☑ Both If the Applicant is not both the owner and operator, please provide the name and address of the other party.
8. Number of onsite employees: Approx. 181	

9. Governmental Code:

- ☑ Privately owned and operated; 0
- ☐ Federally owned and operated; 1
- ☐ State government owned and operated; 2
- ☐ County government owned and operated; 3
- ☐ Municipality government owned and operated; 4
- ☐ District government owned and operated; 5

10. Business Confidentiality Claims

Does this application include confidential information (per 45CSR31)? ☐ Yes ☑ No

If yes, identify each segment of information on each page that is submitted as confidential, and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's *"PRECAUTIONARY NOTICE-CLAIMS OF CONFIDENTIALITY"* guidance.

11. Mailing Address		
Street or P.O. Box: P.O. Box K		
City: Moundsville	**State:** West Virginia	**Zip:** 26041
Telephone Number: (304) 843-6000	**Fax Number:** (304) 843-6080	

12. Facility Location (Physical Address)		
Street: State Route 2	**City:** Cresap/Moundsville	**County:** Marshall
UTM Easting: 516.00 km	**UTM Northing:** 4409.00 km	**Zone:** ☑ 17 or ☐ 18
Directions: From Charleston, WV, take I-77 N to Exit 179. Travel north on State Route 2 approximately 70 miles to Cresap, WV. Facility is located on State Route 2, approximately 9 miles south of Moundsville, WV.		
Portable Source? ☐ Yes ☑ No		
Is facility located within a nonattainment area? ☑ Yes ☐ No		**If yes, for what air pollutants?** Sulfur Dioxide
Is facility located within 50 miles of another state? ☑ Yes ☐ No		**If yes, name the affected state(s).** Ohio, Pennsylvania
Is facility located within 100 km of a Class I Area[1]? ☐ Yes ☑ No **If no, do emissions impact a Class I Area[1]?** ☑ Yes ☐ No		**If yes, name the area(s).**

[1] *Class I areas include Dolly Sods and Otter Creek Wilderness Areas in West Virginia, and Shenandoah National Park and James River Face Wilderness Area in Virginia.*

13. Contact Information		
Responsible Official: Joshua D. Snodgrass		**Title:** Plant Manager
Street or P.O. Box: P.O. Box K		
City: Moundsville	**State:** WV	**Zip:** 26041
Telephone Number: (304) 843-6005	**Cell Number:** (304) 972-7279	
E-mail address: jdsnodgrass@aep.com		
Environmental Contact: G. M. (Matt) Palmer		**Title:** Plant Environmental Coordinator
Street or P.O. Box: P.O. Box K		
City: Moundsville	**State:** WV	**Zip:** 26041
Telephone Number: (304) 843-6048	**Cell Number:** (304) 559-4538	
E-mail address: gmpalmer@aep.com		
Application Preparer: Brandon T. Belcher		**Title:** Environmental Specialist Sr.
Company: AEP Service Corporation		
Street or P.O. Box: 1 Riverside Plaza, 17th Floor		
City: Columbus	**State:** OH	**Zip:** 43215
Telephone Number: (614) 716-1800	**Cell Number:** (304) 541-7437	
E-mail address: btbelcher@aep.com		

14. Facility Description

List all processes, products, NAICS and SIC codes for normal operation, in order of priority. Also list any process, products, NAICS and SIC codes associated with any alternative operating scenarios if different from those listed for normal operation.

Process	Products	NAICS	SIC
Coal Fired Electric Generating Unit	Electricity	221112	4911

Provide a general description of operations.

The Mitchell Plant is a fossil fuel fired electric generation facility and operates under Standard Industrial Code (SIC) 4911. The facility consists of two coal-fired steam generators that provide a steam supply to turbine driven electrical generators, and an oil-fired auxiliary boiler that provides auxiliary steam services to the facility. The facility also includes various supporting operations including by not limited to coal handling, ash handling, gypsum handling, limestone handling, wastewater treatment system filter cake handling, and various tanks with insignificant emissions. The facility has the potential to operate seven days per week, twenty-four hours per day, and 52 weeks per year.

15. Provide an **Area Map** showing plant location as **ATTACHMENT A**.

16. Provide a **Plot Plan(s)**, e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is located as **ATTACHMENT B**. For instructions, refer to “Plot Plan - Guidelines.”

17. Provide a detailed **Process Flow Diagram(s)** showing each process or emissions unit as **ATTACHMENT C**. Process Flow Diagrams should show all emission units, control equipment, emission points, and their relationships.

Section 2: Applicable Requirements

18. Applicable Requirements Summary	
Instructions: Mark all applicable requirements.	
☑ SIP	☐ FIP
☑ Minor source NSR (45CSR13)	☐ PSD (45CSR14)
☑ NESHAP (45CSR34)	☐ Nonattainment NSR (45CSR19)
☑ Section 111 NSPS	☐ Section 112(d) MACT standards
☐ Section 112(g) Case-by-case MACT	☐ 112(r) RMP
☐ Section 112(i) Early reduction of HAP	☐ Consumer/commercial prod. reqts., section 183(e)
☐ Section 129 Standards/Reqts.	☐ Stratospheric ozone (Title VI)
☐ Tank vessel reqt., section 183(f)	☐ Emissions cap 45CSR§30-2.6.1
☐ NAAQS, increments or visibility (temp. sources)	☐ 45CSR27 State enforceable only rule
☑ 45CSR4 State enforceable only rule	☐ Acid Rain (Title IV, 45CSR33)
☐ Emissions Trading and Banking (45CSR28)	☐ **C**ompliance **A**ssurance **M**onitoring (40CFR64)
☐ Cross-State Air Pollution Rule (45CSR43)	

19. Non Applicability Determinations

List all requirements which the source has determined not applicable and for which a permit shield is requested. The listing shall also include the rule citation and the reason why the shield applies.

45 CSR 5: Pursuant to 45CSR5, if 45CSR2 is applicable to the facility, then the facility is exempt from 45CSR5. 45CSR2 is applicable to the facility.

45 CSR 17: Pursuant to 45CSR17, if 45CSR2 is applicable to the facility, then the facility is exempt from 45CSR17. 45CSR2 is applicable to the facility.

40 CFR 60 Subpart D: The fossil fuel fired steam generators potentially affected by this rule have not commenced construction or modification after August 17, 1971.

40 CFR 60 Subpart Da: The electric utility steam generating units potentially affected by this rule have not commenced construction or modification after September 18, 1978.

40 CFR 60 Subpart K: The facility doesn't include storage vessels that are used to store petroleum liquids (as defined in 40 CFR 60.111(b)) and have storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification commenced after June 11, 1973 and prior to May 19, 1978.

☐ Permit Shield

19. Non Applicability Determinations *(Continued)* - *Attach additional pages as necessary.*

List all requirements which the source has determined not applicable and for which a permit shield is requested. The listing shall also include the rule citation and the reason why the shield applies.

40 CFR 60 Subpart Ka: The facility does not include storage vessels that are used to store petroleum liquids (as defined in 40 CFR 60.111(b)) and that have a storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification was commenced after May 18, 1978 and prior to July 23, 1984.

40 CFR 60 Subpart Kb: Storage vessels potentially affected by this rule are exempted because they contain liquids with a maximum true vapor pressure of less than 3.5 kPa, have a storage capacity of less than 40 cubic meters, or have not commenced construction, reconstruction or modification after July 23, 1984.

40 CFR 60 Subpart Y: The coal handling equipment potentially affected by this rule has not been constructed or modified after October 24, 1974.

40 CFR 63 Subpart Q: This facility does not include industrial process cooling towers that have operated with chromium-based water treatment chemicals on or after September 8, 1994.

☐ Permit Shield

20. Facility-Wide Applicable Requirements

List all facility-wide applicable requirements. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*).

45CSR6-3, R30-05100005-2019 (MM01) Section 3.1.1 and 3.1.2 (Open Burning)

40CFR61, 45CSR34, and R30-05100005-2019 (MM01) Section 3.1.3 (Asbestos)

45CSR4, R30-05100005-2019 (MM01) Section 3.1.4 (Odor)

45CSR11-5.2, R30-05100005-2019 (MM01) Section 3.1.5 (Standby Plan)

WV Code 22-5-4(a)(14), R30-05100005-2019 (MM01) Section 3.1.6 (Emission Inventory)

40CFR82 Subpart F, R30-05100005-2019 (MM01) Section 3.1.7 (Ozone-depleting Substances)

45CSR2-5, 45CSR13, R13-2608, 4.1.18, and R30-05100005-2019 (MM01) Section 3.1.9 (Fugitive Particulate Matter Control)

40CFR97.406, , 45CSR43, and R30-05100005-2019 (MM01) Section 3.1.11 (CSAPR NOx Annual Trading Program)

☐ Permit Shield

For all facility-wide applicable requirements listed above, provide monitoring/testing / recordkeeping / reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number and/or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45CSR2, 45CSR10, and WV Code 22-5-4(a)(14-15), R30-05100005-2019 (MM01) Section 3.3.1 (Stack Testing)

45CSR30-5.1.c.2.A, R30-05100005-2019 (MM01) Section 3.4.1 (Monitoring Information)

45CSR30-5.1.c.2.B, R30-05100005-2019 (MM01) Section 3.4.2 (Retention of Records)

45CSR30-5.1.c, R30-05100005-2019 (MM01) Section 3.4.3 (Odors)

45CSR30-5.1.c, R30-05100005-2019 (MM01) Section 3.4.4 (Fugitive Particulate Matter Control)

45CSR30-4.4 and 5.1.c.3, R30-05100005-2019 (MM01) Sections 3.5.1-3.5.3 (Reporting Requirements)

45CSR30-8, R30-05100005-2019 (MM01) Section 3.5.4 (Certified Emissions Statement)

Are you in compliance with all facility-wide applicable requirements? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Page _____ of _____

20. Facility-Wide Applicable Requirements *(Continued)* - *Attach additional pages as necessary.*

List all facility-wide applicable requirements. For each applicable requirement, include the rule citation and/or permit with the condition number.

40CFR97.806, 45CSR43, and R30-05100005-2019 (MM01) Section 3.1.12 (CSAPR NOx Ozone Season Trading Program)

40CFR97.606, 45CSR43, and R30-05100005-2019 (MM01) Section 3.1.13 (CSAPR SO2 Group 1 Trading Program)

☐ Permit Shield

For all facility-wide applicable requirements listed above, provide monitoring/testing/recordkeeping/ reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number and/or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45CSR30-5.3.e, R30-05100005-2019 (MM01) Section 3.5.5 (Compliance Certification)

45CSR30-5.1.c.3.A, R30-05100005-2019 (MM01) Section 3.5.6 (Semi-Annual Monitoring Reports)

R30-05100005-2019 (MM01) Section 3.5.7 (Emergency Reporting)

45CSR30-5.1.c.3, R30-05100005-2019 (MM01) Section 3.5.8 (Deviation Reports)

45CSR30-4.3.h.1.B, R30-05100005-2019 (MM01) Section 3.5.9 (New Applicable Requirements)

Are you in compliance with all facility-wide applicable requirements? ☐ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

21. Active Permits/Consent Orders

Permit or Consent Order Number	Date of Issuance MM/DD/YYYY	List any Permit Determinations that Affect the Permit *(if any)*
	05/12/2004	PD04-042: No permit needed for SCR
	08/05/2004	PD04-064: No permit needed for FGD system
	08/24/2005	PD04-073: No permit needed for urea handling
R13-2608E	05/12/2014	Reg 13 Permit for FGD support equipment, Dry Fly Ash and Ash Landfill project, and Aux. Boiler rebuild project/capacity factor limit.
U.S. District Court Consent Decree regarding Civil Actions C2-99-1182, C2-05-360, and C2-04-1098	12/13/2007	Consent Decree for NSR lawsuits
R33-3948-2027-6	12/19/2022	Acid Rain Permit
G60-C057A	08/08/2014	Emergency Generator General Permit

22. Inactive Permits/Obsolete Permit Conditions

Permit Number	Date of Issuance MM/DD/YYYY	Permit Condition Number
R13-2608 through R13-2608D	Various	Permits were revised and replaced with subsequent versions.
G60-C057	10/11/2013	Permit was revised and replaced with subsequent version.

Page _____ of _____

Section 3: Facility-Wide Emissions

23. Facility-Wide Emissions Summary [Tons per Year]

Criteria Pollutants	Potential Emissions
Carbon Monoxide (CO)	4743.23
Nitrogen Oxides (NO_X)	36332.05
Lead (Pb)	3.643
Particulate Matter ($PM_{2.5}$)[1]	1096.2
Particulate Matter (PM_{10})[1]	3169.0
Total Particulate Matter (TSP)	5423.79
Sulfur Dioxide (SO_2)	89743.04
Volatile Organic Compounds (VOC)	559.82
Hazardous Air Pollutants[2]	Potential Emissions
Hydrogen Chloride	12337
Hydrogen Fluoride	1071
Selenium	48.45
Manganese	3.77
Nickel	1.69
Arsenic	5.62
Mercury Compounds	2.13
Beryllium	13.37
Chromium	2.00
Cobalt	0.74
Lead	3.65
Regulated Pollutants other than Criteria and HAP	Potential Emissions

[1]$PM_{2.5}$ and PM_{10} are components of TSP.
[2]For HAPs that are also considered PM or VOCs, emissions should be included in both the HAPs section and the Criteria Pollutants section.

Page _____ of _____

Section 4: Insignificant Activities

24. Insignificant Activities (Check all that apply)		
☑	1.	Air compressors and pneumatically operated equipment, including hand tools.
☑	2.	Air contaminant detectors or recorders, combustion controllers or shutoffs.
☑	3.	Any consumer product used in the same manner as in normal consumer use, provided the use results in a duration and frequency of exposure which are not greater than those experienced by consumer, and which may include, but not be limited to, personal use items; janitorial cleaning supplies, office supplies and supplies to maintain copying equipment.
☑	4.	Bathroom/toilet vent emissions.
☑	5.	Batteries and battery charging stations, except at battery manufacturing plants.
☑	6.	Bench-scale laboratory equipment used for physical or chemical analysis, but not lab fume hoods or vents. Many lab fume hoods or vents might qualify for treatment as insignificant (depending on the applicable SIP) or be grouped together for purposes of description.
☐	7.	Blacksmith forges.
☑	8.	Boiler water treatment operations, not including cooling towers.
☑	9.	Brazing, soldering or welding equipment used as an auxiliary to the principal equipment at the source.
☐	10.	CO_2 lasers, used only on metals and other materials which do not emit HAP in the process.
☑	11.	Combustion emissions from propulsion of mobile sources, except for vessel emissions from Outer Continental Shelf sources.
☑	12.	Combustion units designed and used exclusively for comfort heating that use liquid petroleum gas or natural gas as fuel.
☑	13.	Comfort air conditioning or ventilation systems not used to remove air contaminants generated by or released from specific units of equipment.
☑	14.	Demineralized water tanks and demineralizer vents.
☐	15.	Drop hammers or hydraulic presses for forging or metalworking.
☑	16.	Electric or steam-heated drying ovens and autoclaves, but not the emissions from the articles or substances being processed in the ovens or autoclaves or the boilers delivering the steam.
☐	17.	Emergency (backup) electrical generators at residential locations.
☑	18.	Emergency road flares.
☐	19.	Emission units which do not have any applicable requirements and which emit criteria pollutants (CO, NO_x, SO_2, VOC and PM) into the atmosphere at a rate of less than 1 pound per hour and less than 10,000 pounds per year aggregate total for each criteria pollutant from all emission units. Please specify all emission units for which this exemption applies along with the quantity of criteria pollutants emitted on an hourly and annual basis:

24. Insignificant Activities (Check all that apply)		
☐	20.	Emission units which do not have any applicable requirements and which emit hazardous air pollutants into the atmosphere at a rate of less than 0.1 pounds per hour and less than 1,000 pounds per year aggregate total for all HAPs from all emission sources. This limitation cannot be used for any source which emits dioxin/furans nor for toxic air pollutants as per 45CSR27. Please specify all emission units for which this exemption applies along with the quantity of hazardous air pollutants emitted on an hourly and annual basis:
☐	21.	Environmental chambers not using hazardous air pollutant (HAP) gases.
☑	22.	Equipment on the premises of industrial and manufacturing operations used solely for the purpose of preparing food for human consumption.
☐	23.	Equipment used exclusively to slaughter animals, but not including other equipment at slaughterhouses, such as rendering cookers, boilers, heating plants, incinerators, and electrical power generating equipment.
☑	24.	Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.
☑	25.	Equipment used for surface coating, painting, dipping or spray operations, except those that will emit VOC or HAP.
☑	26.	Fire suppression systems.
☑	27.	Firefighting equipment and the equipment used to train firefighters.
☐	28.	Flares used solely to indicate danger to the public.
☑	29.	Fugitive emission related to movement of passenger vehicle provided the emissions are not counted for applicability purposes and any required fugitive dust control plan or its equivalent is submitted.
☐	30.	Hand-held applicator equipment for hot melt adhesives with no VOC in the adhesive formulation.
☑	31.	Hand-held equipment for buffing, polishing, cutting, drilling, sawing, grinding, turning or machining wood, metal or plastic.
☐	32.	Humidity chambers.
☑	33.	Hydraulic and hydrostatic testing equipment.
☑	34.	Indoor or outdoor kerosene heaters.
☑	35.	Internal combustion engines used for landscaping purposes.
☐	36.	Laser trimmers using dust collection to prevent fugitive emissions.
☑	37.	Laundry activities, except for dry-cleaning and steam boilers.
☐	38.	Natural gas pressure regulator vents, excluding venting at oil and gas production facilities.
☑	39.	Oxygen scavenging (de-aeration) of water.
☑	40.	Ozone generators.

24. Insignificant Activities (Check all that apply)		
☑	41.	Plant maintenance and upkeep activities (e.g., grounds-keeping, general repairs, cleaning, painting, welding, plumbing, re-tarring roofs, installing insulation, and paving parking lots) provided these activities are not conducted as part of a manufacturing process, are not related to the source's primary business activity, and not otherwise triggering a permit modification. (Cleaning and painting activities qualify if they are not subject to VOC or HAP control requirements. Asphalt batch plant owners/operators must still get a permit if otherwise requested.)
☑	42.	Portable electrical generators that can be moved by hand from one location to another. "Moved by Hand" means that it can be moved without the assistance of any motorized or non-motorized vehicle, conveyance, or device.
☑	43.	Process water filtration systems and demineralizers.
☑	44.	Repair or maintenance shop activities not related to the source's primary business activity, not including emissions from surface coating or de-greasing (solvent metal cleaning) activities, and not otherwise triggering a permit modification.
☑	45.	Repairs or maintenance where no structural repairs are made and where no new air pollutant emitting facilities are installed or modified.
☑	46.	Routing calibration and maintenance of laboratory equipment or other analytical instruments.
☐	47.	Salt baths using nonvolatile salts that do not result in emissions of any regulated air pollutants. Shock chambers.
☐	48.	Shock chambers.
☐	49.	Solar simulators.
☑	50.	Space heaters operating by direct heat transfer.
☑	51.	Steam cleaning operations.
☑	52.	Steam leaks.
☐	53.	Steam sterilizers.
☑	54.	Steam vents and safety relief valves.
☑	55.	Storage tanks, reservoirs, and pumping and handling equipment of any size containing soaps, vegetable oil, grease, animal fat, and nonvolatile aqueous salt solutions, provided appropriate lids and covers are utilized.
☑	56.	Storage tanks, vessels, and containers holding or storing liquid substances that will not emit any VOC or HAP. Exemptions for storage tanks containing petroleum liquids or other volatile organic liquids should be based on size limits such as storage tank capacity and vapor pressure of liquids stored and are not appropriate for this list.
☐	57.	Such other sources or activities as the Director may determine.
☑	58.	Tobacco smoking rooms and areas.
☑	59.	Vents from continuous emissions monitors and other analyzers.

Section 5: Emission Units, Control Devices, and Emission Points

25. Equipment Table
Fill out the **Title V Equipment Table** and provide it as **ATTACHMENT D**.
26. Emission Units
For each emission unit listed in the **Title V Equipment Table**, fill out and provide an **Emission Unit Form** as **ATTACHMENT E**.
For each emission unit not in compliance with an applicable requirement, fill out a **Schedule of Compliance Form** as **ATTACHMENT F**.
27. Control Devices
For each control device listed in the **Title V Equipment Table**, fill out and provide an **Air Pollution Control Device Form** as **ATTACHMENT G**.
For any control device that is required on an emission unit in order to meet a standard or limitation for which the potential pre-control device emissions of an applicable regulated air pollutant is greater than or equal to the Title V Major Source Threshold Level, refer to the **Compliance Assurance Monitoring (CAM) Form(s)** for CAM applicability. Fill out and provide these forms, if applicable, for each Pollutant Specific Emission Unit (PSEU) as **ATTACHMENT H**.

Page _____ of _____

Section 6: Certification of Information

28. Certification of Truth, Accuracy and Completeness and Certification of Compliance

Note: This Certification must be signed by a responsible official as defined in 45CSR§30-2.38.

a. Certification of Truth, Accuracy and Completeness

I certify that I am a responsible official (as defined at 45CSR§30-2.38) and am accordingly authorized to make this submission on behalf of the owners or operators of the source described in this document and its attachments. I certify under penalty of law that I have personally examined and am familiar with the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine and/or imprisonment.

b. Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

Responsible official (type or print)

Name:	Title:
Joshua D. Snodgrass	Plant Manager

Responsible official's signature:

Signature: [signature] Signature Date: 5/9/24

(Must be signed and dated in blue ink or have a valid electronic signature)

Note: Please check all applicable attachments included with this permit application:

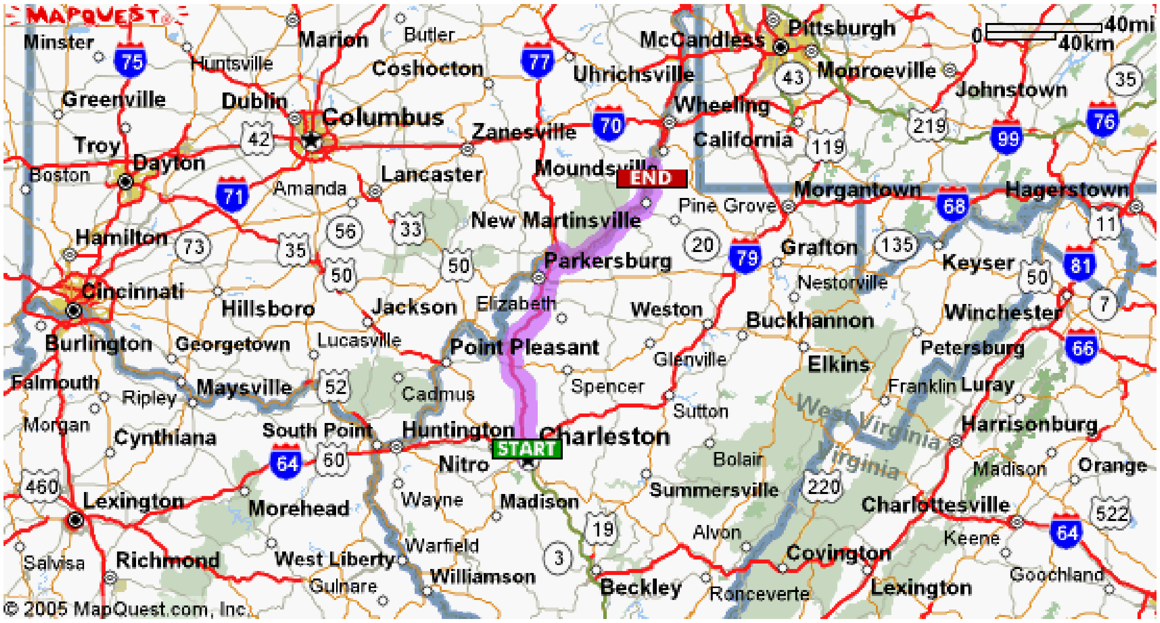
- ☑ ATTACHMENT A: Area Map
- ☑ ATTACHMENT B: Plot Plan(s)
- ☑ ATTACHMENT C: Process Flow Diagram(s)
- ☑ ATTACHMENT D: Equipment Table
- ☑ ATTACHMENT E: Emission Unit Form(s)
- ☐ ATTACHMENT F: Schedule of Compliance Form(s)
- ☑ ATTACHMENT G: Air Pollution Control Device Form(s)
- ☑ ATTACHMENT H: Compliance Assurance Monitoring (CAM) Form(s)

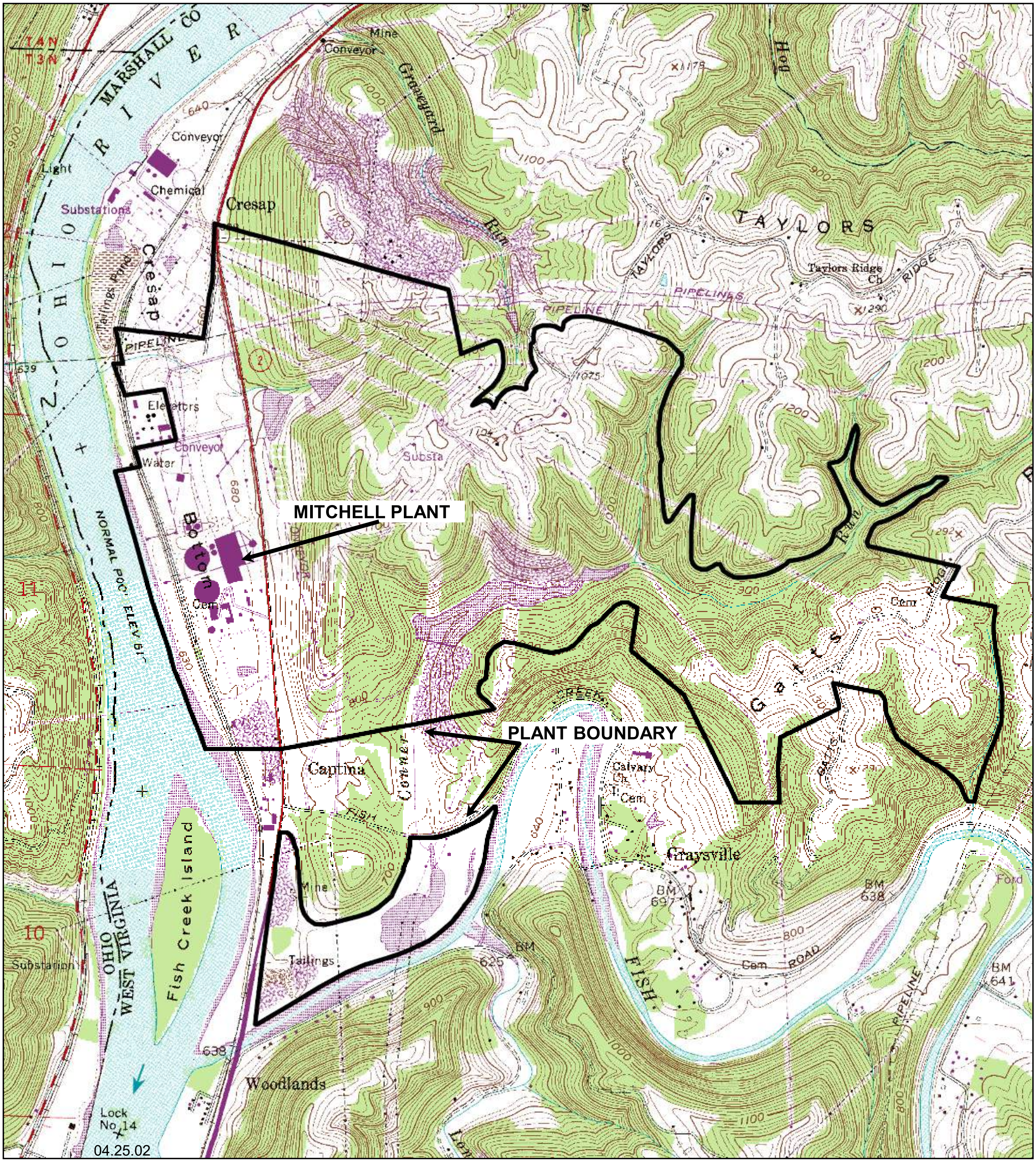
All of the required forms and additional information can be found and downloaded from, the DEP website at www.dep.wv.gov/daq, ***requested by phone (304) 926-0475, and/or obtained through the mail.***

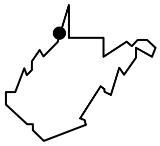
Attachment A

Area Map

Driving directions to Mitchell Plant: From Charleston, take Interstate 77 North to Exit 179. Travel north on State Route 2 approximately 70 miles to Cresap. Facility is located on Route 2 approximately nine miles south of Moundsville, WV.







N

Powhatan Point, W.VA. - OH
Quadrangle
USGS Topographic Map

0 ½ 1mi

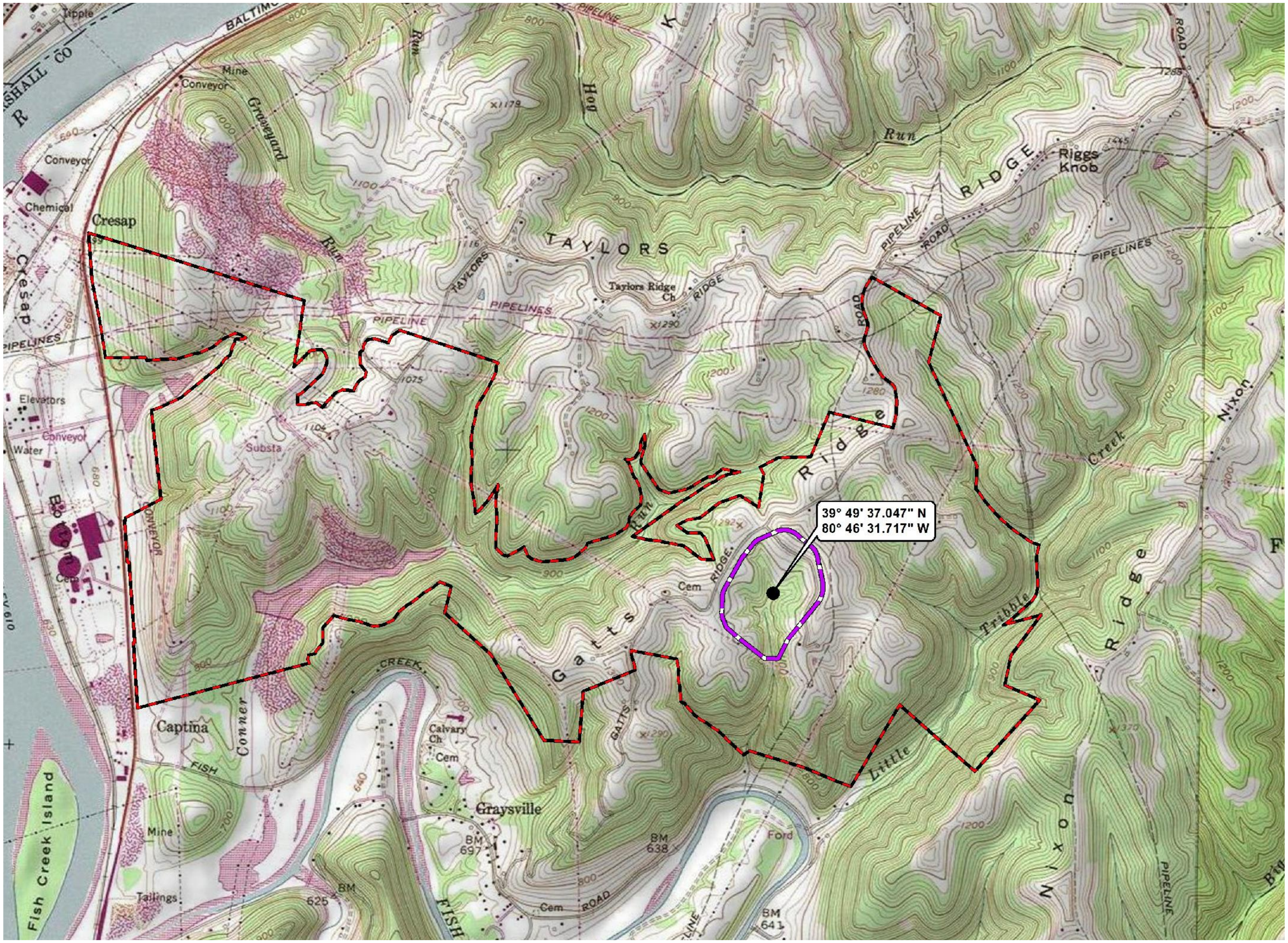
Plant Latitude 39° 49' 45"
Plant Longitude 80° 48' 59"

Wheeling Power Company
Mitchell Plant

Facility Boundary

Air Quality Services

Mitchell Plant Dry Fly Ash Landfill Boundary

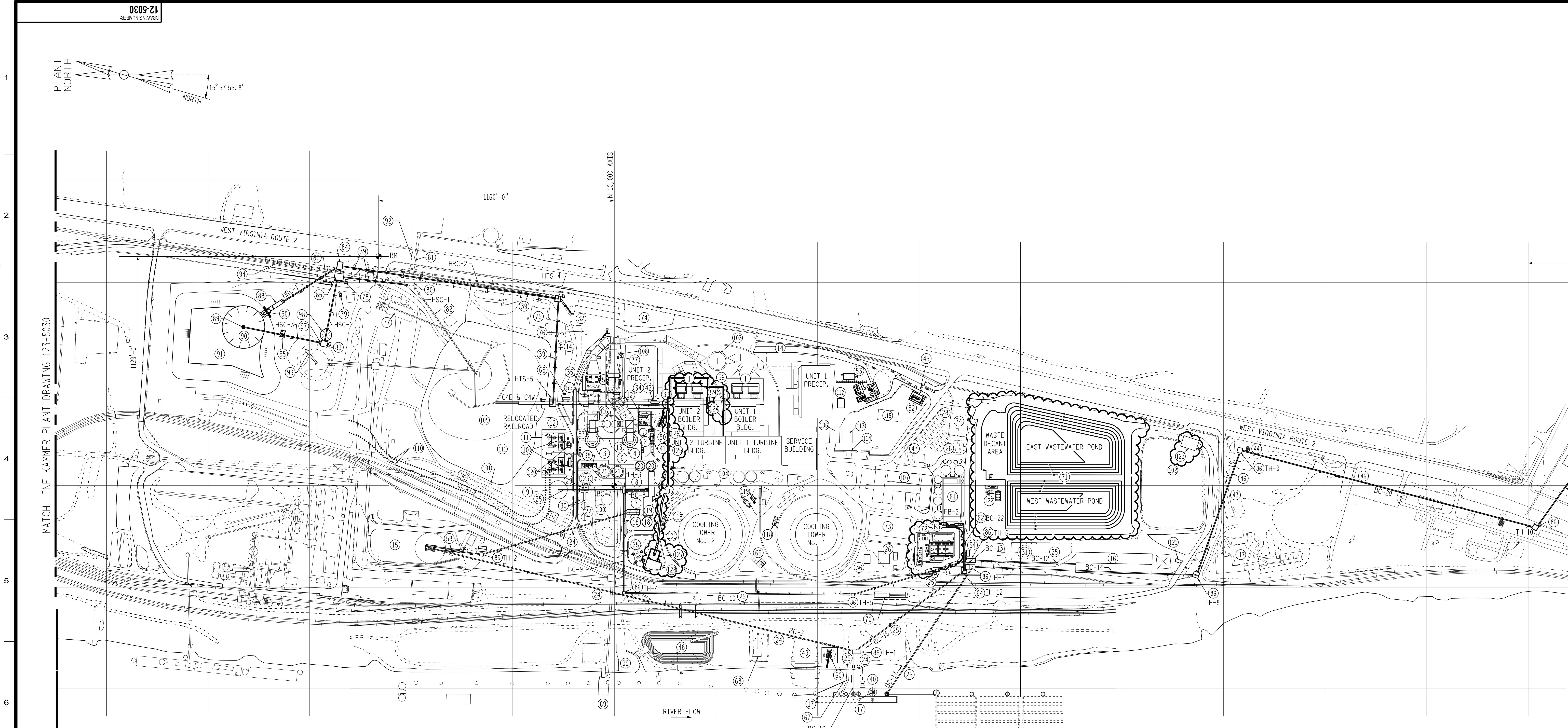


Attachment B

Plot Plan

GENERAL NOTES

1. WORK THIS DRAWING WITH KAMMER PLANT DRAWING 1-5030.



FOR CHANGES RELATED TO THE CCR AND ELG PROJECT, WORK THIS DRAWING WITH THE FOLLOWING REFERENCES:

12-507201	GENERAL ARRANGMENT POND AREA PLAN	1-507200	EQUIPMENT SETTING PLAN UNIT 1 BOTTOM ASH AREA
12-508200	GENERAL ARRANGMENT WASTEWATER TREATMENT BUILDING ENLARGED PLAN	1-507202	EQUIPMENT SETTING PLAN BOTTOM ASH BUNKER AREA
0-300004	POND CLOSURE AND REPURPOSING COVER SHEET AND DRAWING INDEX	2-507200	EQUIPMENT SETTING PLAN UNIT 2 BOTTOM ASH AREA

NOTES:

1. BACKGROUND SHOWN IS FROM EXISTING AERIAL SURVEY GEO ONE DRAWING 01-0340, SHEET 1 OF 1, DATED 4-13-01, TITLED AEP MITCHELL PLANT.

LEGEND:

1 SCR REACTORS
2 UREA TO AMMONIA SYSTEM
3 UNIT 1 FGD ABSORBER
4 UNIT 2 FGD ABSORBER
5 ID FANS
6 FGD BUILDING
7 LIMESTONE PREPARATION BUILDING
8 GYPSUM DEWATERING BUILDING
9 GYPSUM EMERGENCY STACKOUT PILE
10 FGD AUXILIARY TRANSFORMERS
11 FGD SUBSTATION
12 ELEVATED WET PRECIPITATORS (FUTURE)
13 CEMS BUILDINGS (IN STACK UNDER FLUES)
14 FUTURE MERCURY REMOVAL BAGHOUSE & BOOSTER FANS
15 LIMESTONE PILE
16 GYPSUM STORAGE BUILDING
17 1500 DWT BARGE
18 LIMESTONE SLURRY TANKS
19 LIMESTONE SILOS
20 RECLAIM WATER TANKS
21 HYDROCLONE FEED TANKS
22 SERVICE WATER TANKS
23 MAINTENANCE SLURRY STORAGE TANK
24 LIMESTONE CONVEYOR
25 GYPSUM CONVEYOR
26 RELOCATED WAREHOUSE (REPLACES EXISTING WAREHOUSE)
27 ADDITIONAL BARGE CELLS
28 OUTAGE TRAILERS AS REQUIRED
29 MAINTENANCE SLURRY BUILDING
30 EMERGENCY QUENCH PUMPS
31 METAL CLEANING TANK (EXISTING)
32 CONSTRUCTION FACILITIES BUILDING
33 PIPE BRIDGE TO UREA AREA
34 SCR SUBSTATION
35 ID FAN ELECTRICAL BUILDING
36 RELOCATED OIL STORAGE
37 RELOCATED ASKAREL COLLECTION TANK
38 FGD STATION SERVICE TRANSFORMERS
39 COAL BLENDING CONVEYOR
40 BARGE UNLOADING/LOADING FACILITY
41 UREA UNLOADING BUILDING
42 UREA ELECTRICAL BUILDING
43 TRUCK WEIGH SCALE (REED MINERALS)
44 LEACH FIELD
45 NEW TRUCK DELIVERY GATE-REMOTELY OPERATED FROM EXISTING GATE HOUSE
46 BELT CONVEYOR
47 OUTAGE TRAILER AREA SHOWER & RESTROOMS
48 CONTAINMENT POND
49 BARGE UNLOADING RAMP
50 BOILER MAINTENANCE CRANE
51 GYPSUM WALLBOARD STORAGE BUILDING
52 SPARE TRANSFORMERS
53 DRY S03 SORBENT INJECTION SYSTEM
54 MATERIALS HANDLING SUB-STATION #2
55 ID FAN OUTLET DUCT DAMPER SEAL AIR FANS
56 AUXILIARY BOILER STACK
57 13.5 kV BRIDGE
58 LIMESTONE RECLAIM TUNNEL
59 BOILER MODS OUTDOOR MCC
60 TEMPORARY CRANE FOR BARGE UNLOADING
61 CPS TREATMENT FACILITY
62 CPS WASTE CONVEYOR
63 CPS WASTE PILE & PAD
64 CPS WASTE TRANSFER HOUSE
65 CONVEYOR 4EW TUNNEL HEATING OIL TANK
66 HYDROGEN BULK STORAGE AND UNLOADING
67 EXISTING FUEL OIL UNLOADING
68 RIVER WATER MAKE-UP PUMP HOUSE
69 EXISTING COAL BARGE UNLOADER
70 EXISTING SEWAGE PLANT
71 WASTEWATER PONDS
72 WASTEWATER TREATMENT BUILDING
73 PRECIPITATOR PARTS WAREHOUSE
74 69KV FISH CREEK SUB-STATION
75 TRACTOR SHED
76 EXISTING DIESEL FUEL STORAGE TANK (BURIED)
77 HEAVY EQUIPMENT STORAGE BUILDING
78 DELUGE VALVE BUILDING
79 COAL BLENDING SYSTEM ELECTRICAL VAULT
80 EXISTING CONSOL TRANSFER STATION #1
81 EXISTING CONSOL CONVEYOR 31 (NOT IN USE)
82 EXISTING CONVEYOR 1 (NOT IN USE)
83 STATION HTS-3
84 STATION HTS-2B
85 STATION HTS-2A
86 TRANSFER HOUSE
87 COAL BLENDING SYSTEM ELECTRICAL ROOM
88 RECLAIM TUNNEL
89 ST-1 STACKING TUBE
90 HIGH SULFUR COAL SHORT-TERM ACTIVE PILE
91 HIGH SULFUR COAL LONG-TERM STORAGE
92 EXISTING CONSOL CONVEYOR C-3100
93 R-9 RADIAL STACKER
94 EXISTING CONVEYOR #64 TO KAMMER
95 HSC-3 DRIVE/ GTU TOWER
96 HFB-1 FEEDER/ BREAKER
97 FEED RECEIVER HOPPER
98 SCALE TEST PILE
99 STA. R1
100 FUEL OIL STORAGE TANKS
101 345 KV OVERHEAD LINES AND UNIT 2 TOWER
102 CLEARWELL POND
103 EXISTING STACK
104 CONDENSATE TANKS
105 FUTURE EXPANSION
106 UTILITY SHOWER BLDG.
107 WAREHOUSES
108 UNIT 2 OVERFLOW SUMP
109 ACTIVE COAL PILE
110 138 KV UNDERGROUND LINES FROM KAMMER
111 LOW SULFUR COAL LONG TERM STORAGE
112 UNIT 1 OVERFLOW SUMP
113 TRAINING CENTER
114 MAIN GATE HOUSE (GATE 3)
115 CONTROL ROOM SIMULATOR BUILDING
116 FGD STACK - ℄ @ N 10,015, E 10,304
117 BLACK BEAUTY PLANT
118 COOLING TOWER CHEMICAL INJECTION TANKS & PUMPS
119 UNIT 1&2 BLACK START DIESEL GENERATOR AND PDC BUILDING
120 FGD BLACK START DIESEL GENERATOR AND PDC BUILDING
121 GATE 4 GUARD HOUSE
122 POND ENHANCEMENT AREA
123 TEMPORARY TREATMENT AREA
124 UNIT 1 TRANSFER TOWER
125 UNIT 12 COMMON SICON CONVEYOR
126 UNIT 2 TRANSFER TOWER
127 UNIT 12 BOTTOM ASH BUNKER
128 UNIT 12 BOTTOM ASH BUNKER LOADING PAD

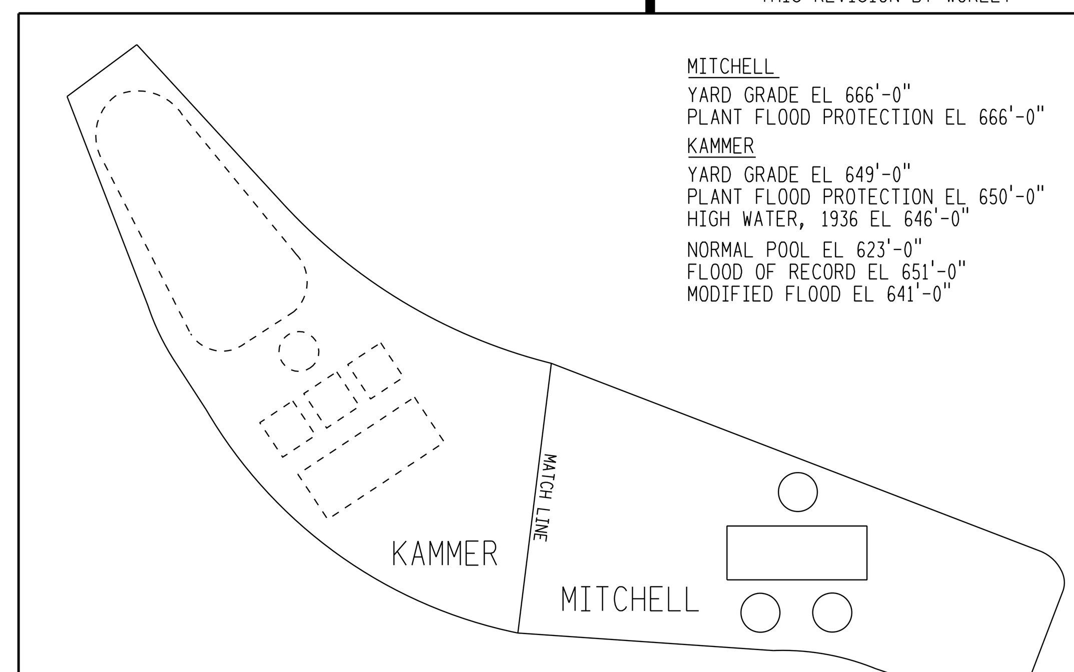
ISSUED FOR REVIEW
UPDATED FOR CCR/ELG PROJECT
(A6-C7, E8, F3-F5, H5-K4, J8)

REV	DATE	DRAWN	CHECKED	REVIEWED	LEAD DESIGNER	ENGINEER/ TECH SPEC	LEAD DISC ENGINEER	PROJ ENGR MANAGER
20B	11/18/21	MTM		CLS	MSC	KL	CLS	TMM

THIS REVISION BY WORLEY

DATE	NO.	DESCRIPTION	APPD.
	19	PER PROJECT ID MLP-0-MDI-16-103183: ADDED GATE 4 GUARD HOUSE (H, J9) (K5). QA/QC NO. MI-012017 TRA	TRA KFB DDS JAR TVR

REVISIONS



KEY PLAN

MITCHELL
YARD GRADE EL 666'-0"
PLANT FLOOD PROTECTION EL 666'-0"

KAMMER
YARD GRADE EL 649'-0"
PLANT FLOOD PROTECTION EL 650'-0"
HIGH WATER, 1936 EL 646'-0"

NORMAL POOL EL 623'-0"
FLOOD OF RECORD EL 651'-0"
MODIFIED FLOOD EL 641'-0"

THIS DRAWING IS CLASSIFIED AS:

AEP CONFIDENTIAL

REFERENCE AEP's CORPORATE INFORMATION SECURITY POLICY

OHIO POWER COMPANY

MITCHELL PLANT

CRESAP — WEST VIRGINIA

GENERAL ARRANGEMENT

PLOT PLAN
MITCHELL SITE

UNIT:	DRAWING NUMBER:	REV:
12	5030	20B

SCALE: 1"=200'-0" — MECHANICAL ENGINEERING

DR: ____
CH: ____
SUP: ____
ENG: ____
DATE: 8-31-67
APPROVED BY ____

AMERICAN ELECTRIC POWER

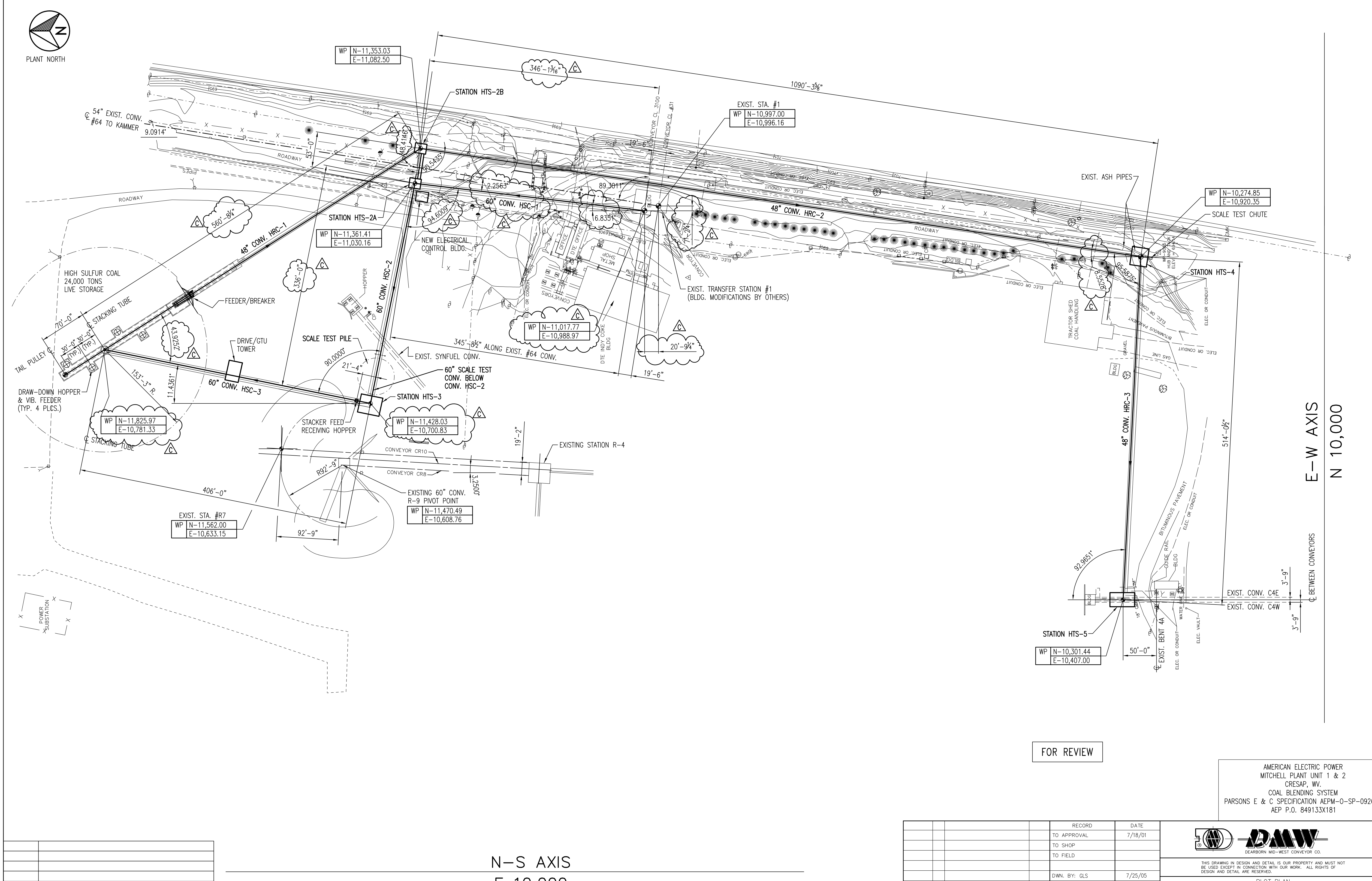
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

12-5030

PLOT DATE: 11/23/2021
PLOT TIME: 1:29:59 PM
BY: Marc.Miravalles

CROSS REFS:

DRAWING NUMBER 12-5030



FOR REVIEW

AMERICAN ELECTRIC POWER
MITCHELL PLANT UNIT 1 & 2
CRESAP, WV.
COAL BLENDING SYSTEM
PARSONS E & C SPECIFICATION AEPM-0-SP-092603
AEP P.O. 849133X181

DWG. NO.	REFERENCE DRAWING
L-003	DESIGN CRITERIA & GENERAL NOTES
L-002	FLOW DIAGRAM
L-000	TITLE SHEET & DRAWING LIST

DATE	No.	REVISION	BY
9/2/05	C	REVISED PER SITE VISIT 8/16/05 FOR FINAL CLIENT REVIEW	JLB
8/4/05	B	REVISED LAYOUT PER SITE VISIT	JLB
7/18/01	A	ISSUED FOR CLIENT REVIEW	JLB

RECORD	DATE
TO APPROVAL	7/18/01
TO SHOP	
TO FIELD	
DWN. BY: GLS	7/25/05
CHK. BY: CJS	7/26/05
APP. BY:	

JOB NO. 05-7680

DEARBORN MID-WEST CONVEYOR CO.

PLOT PLAN

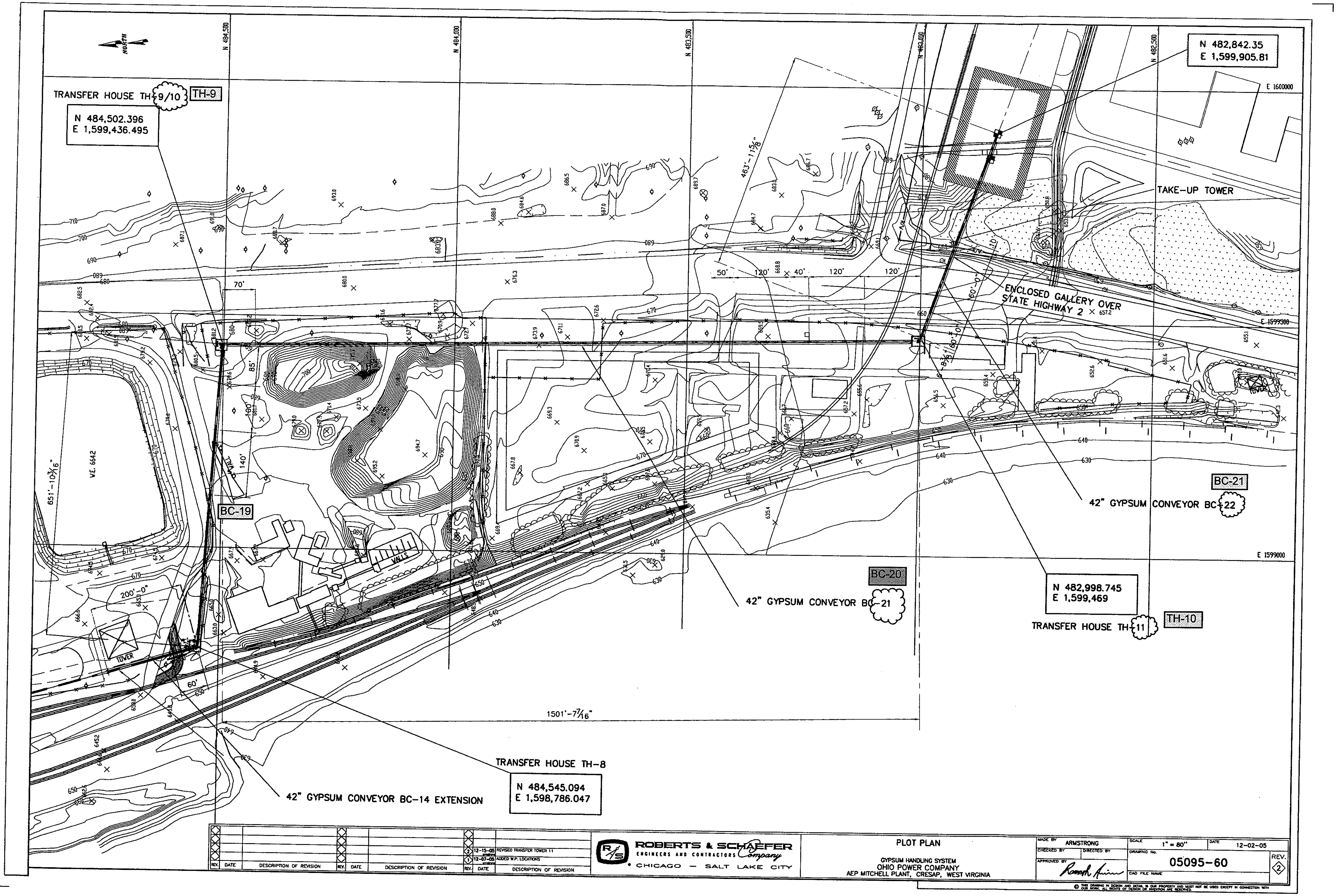
MITCHELL PLANT UNITS 1 & 2 – COAL BLENDING SYSTEM

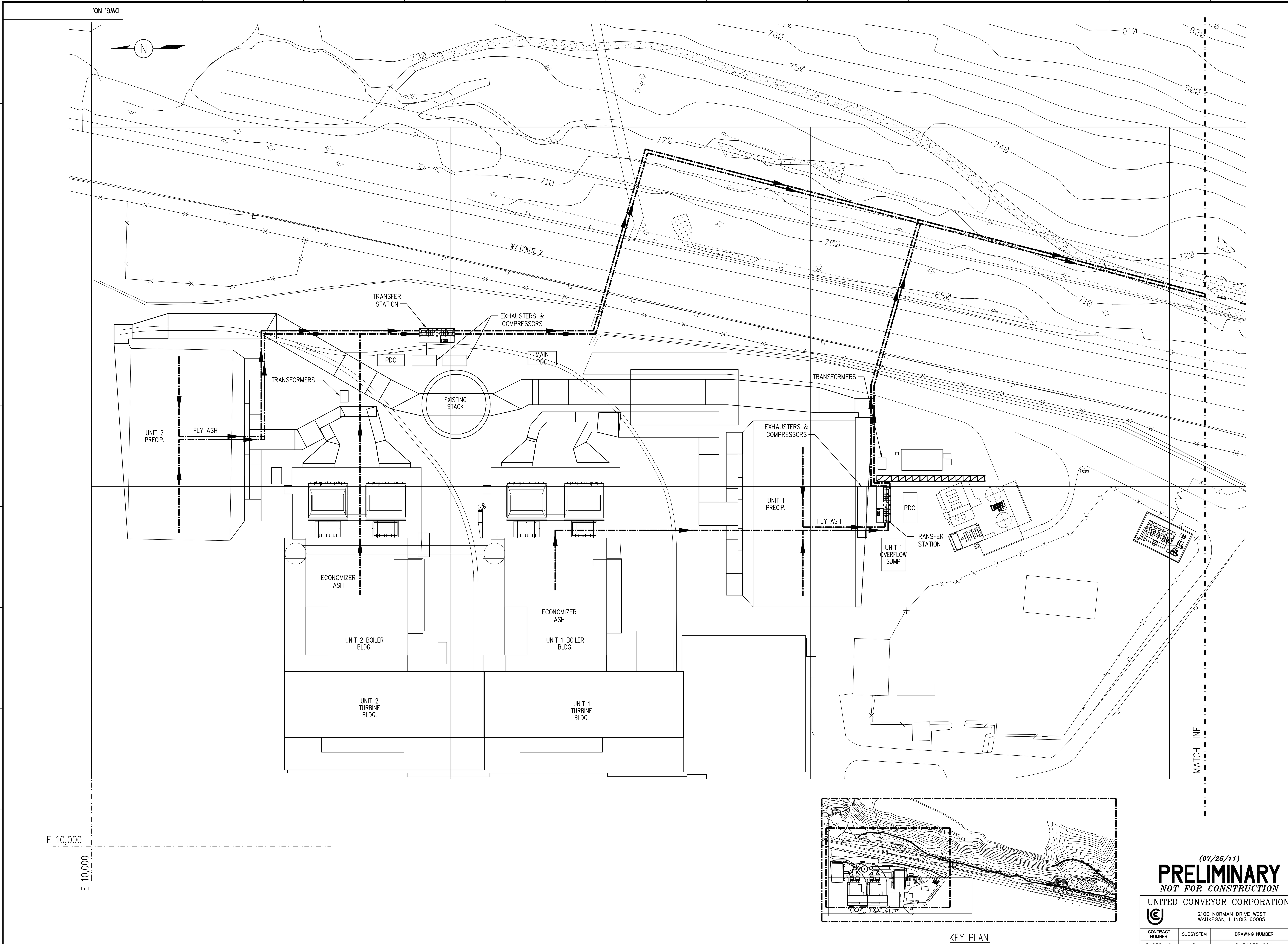
SCALE 1"=60'-0" | DWG. NO. L-001 | REV. NO. C

FILE NAME: G:\0521\L-001.dwg

PLOTTED: (JLB) 02-SEP-2005 13:01

PLOT SCALE:


NORTH
N 484,500
N 484,000
N 483,500
N 483,000
N 482,500
TRANSFER HOUSE TH-9/10
TH-9
N 484,502.396
E 1,599,436.495
N 482,842.35
E 1,599,905.81
E 1600000
TAKE-UP TOWER
463'-11⅝"
50'
120'
40'
120'
120'
70'
85'
180'
140'
60'
ENCLOSED GALLERY OVER
STATE HIGHWAY 2
E 1599500
651'-10¾"
200'-0"
BC-19
TOWER
BC-21
42" GYPSUM CONVEYOR BC-22
E 1599000
BC-20
42" GYPSUM CONVEYOR BC-21
N 482,998.745
E 1,599,469
TRANSFER HOUSE TH-11
TH-10
1501'-7⁷⁄₁₆"
TRANSFER HOUSE TH-8
N 484,545.094
E 1,598,786.047
42" GYPSUM CONVEYOR BC-14 EXTENSION
REV. DATE DESCRIPTION OF REVISION
2 12-15-05 REVISED TRANSFER TOWER 11
1 12-07-05 ADDED W.P. LOCATIONS
ROBERTS & SCHAEFER Company
ENGINEERS AND CONTRACTORS
CHICAGO — SALT LAKE CITY
PLOT PLAN
GYPSUM HANDLING SYSTEM
OHIO POWER COMPANY
AEP MITCHELL PLANT, CRESAP, WEST VIRGINIA
MADE BY ARMSTRONG
CHECKED BY
DIRECTED BY
APPROVED BY
SCALE 1" = 80'
DATE 12-02-05
DRAWING No. 05095-60
REV. 2
CAD FILE NAME



(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION

UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST
WAUKEGAN, ILLINOIS 60085

CONTRACT NUMBER	SUBSYSTEM	DRAWING NUMBER
54658–19	R	C–54658–004

DSGN	MAM	CHKD	–	APPD (ENGR)	–	APPD (PROJ)	–

GENERAL NOTES

REFERENCE DRAWINGS

07/25/11	A	ISSUED FOR CONCEPTUAL REVIEW	TMW

REVISIONS

OHIO POWER COMPANY

MITCHELL PLANT

CRESAP WEST VIRGINIA

DRY FLY ASH CONVERSION
UNIT 1 & 2
FLY ASH REMOVAL SYSTEM
SITE PLAN

DWG. NO.

SCALE: 1/32"=1'-0" MECHANICAL ENGINEERING DIVISION

DR: MAM
CH:
ENGR:
PROJ ENGR:
DATE: 7/23/2011
APPROVED BY

AMERICAN ELECTRIC POWER

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

IGS0700

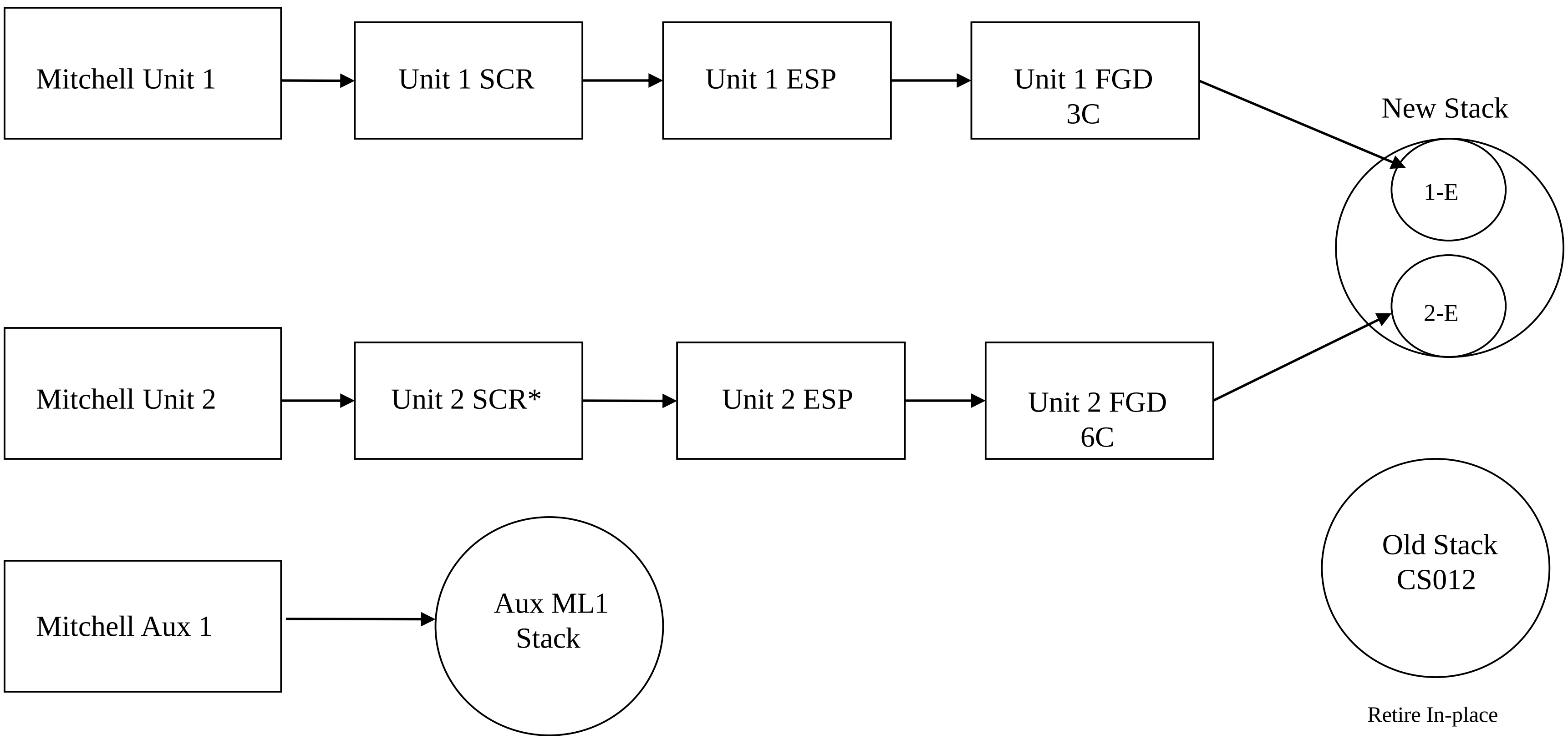
Rev. No: .
Plot Date: .
Plotted by: .


DWG. NO.
MATCH LINE
20' WIDE ACCESS ROAD
(6) 10" DIA FLY ASH REMOVAL PIPES = 10' WIDE
SERVICE BLDG
SILO #1
SILO #2
SILO #3
PROCESS STORAGE TANK
FIRE PUMP HOUSE
FIRE WATER STORAGE TANK
COLLECTION SUMP
CONTACT POND (IF NEEDED)
OUTBOUND TRUCK SCALE
INBOUND TRUCK SCALE
FENCE
WV STATE ROUTE NO 2
KEY PLAN
(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST WAUKEGAN, ILLINOIS 60085
CONTRACT NUMBER 54658-19
SUBSYSTEM R
DRAWING NUMBER C-54658-006
DSGN MAM
REVISIONS
" THIS DRAWING IS THE PROPERTY OF THE AMERICAN ELECTRIC POWER SERVICE CORP. AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT THE WRITTEN CONSENT OF THE AEP SERVICE CORP., OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST, AND IS TO BE RETURNED UPON REQUEST."
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP WEST VIRGINIA
DRY FLY ASH CONVERSION
UNIT 1 & 2
FLY ASH REMOVAL SYSTEM
SITE PLAN
SCALE: 1/32"=1'-0"
DR: MAM
DATE: 7/23/2011
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

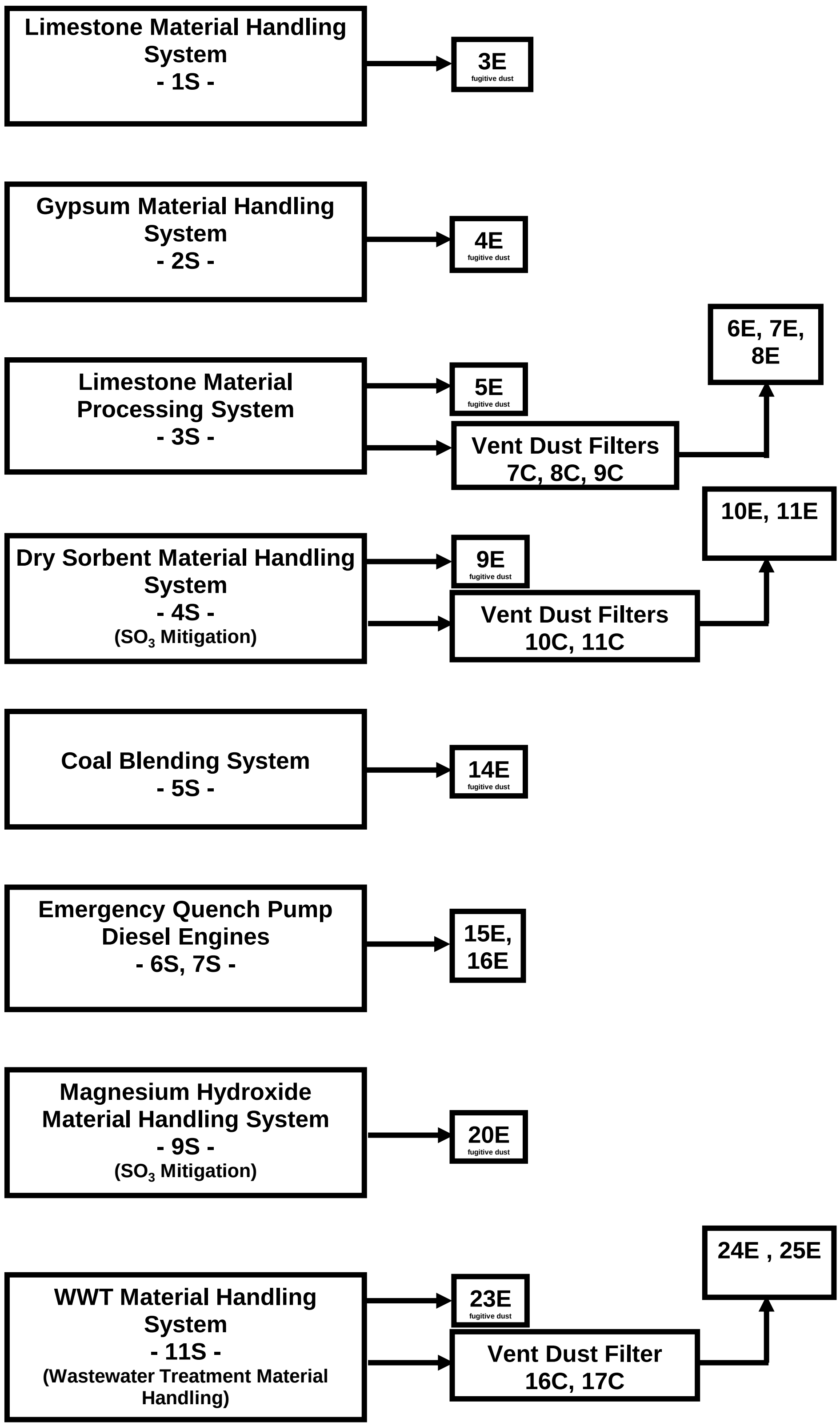
Attachment C

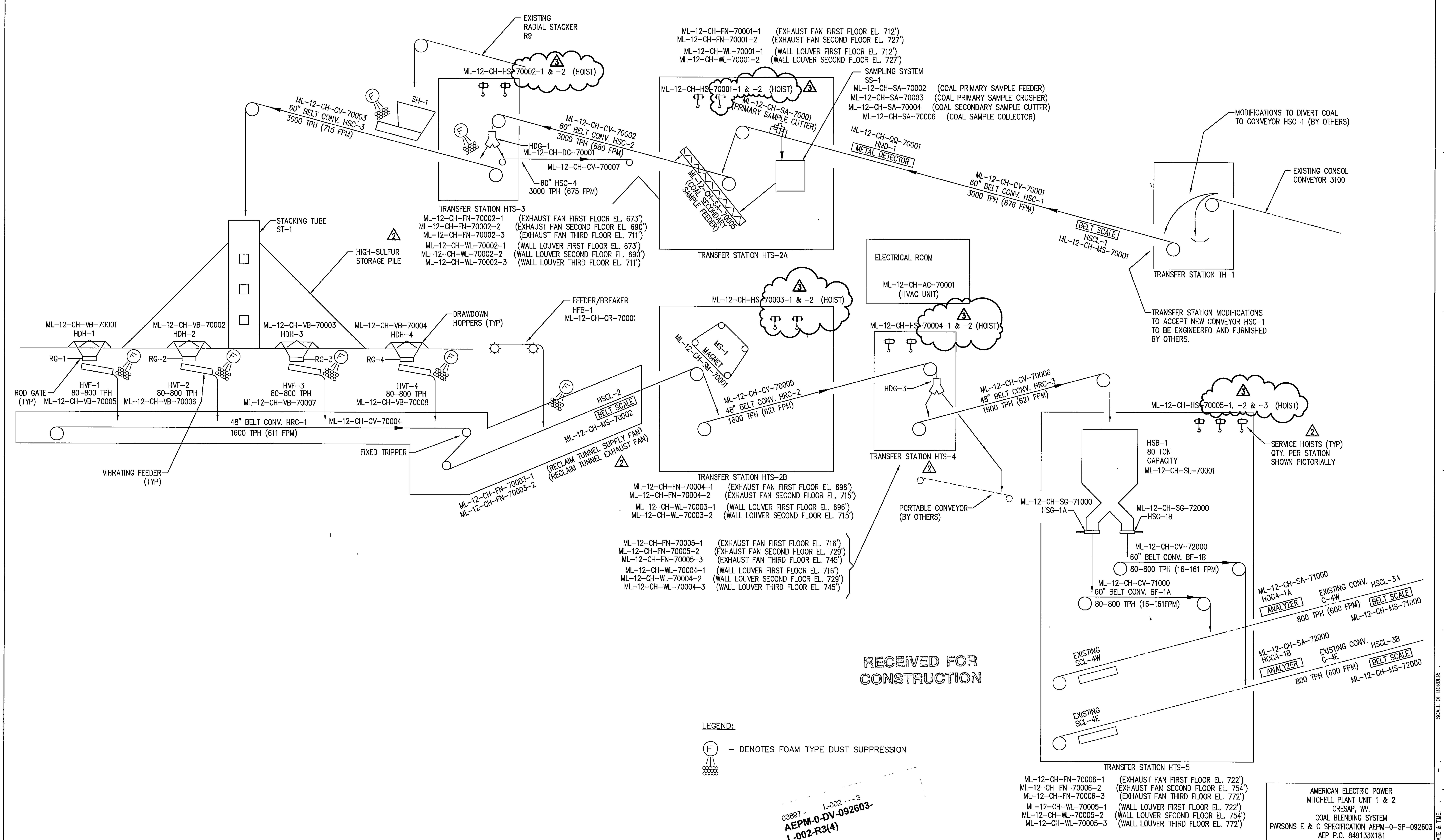
Process Flow Diagrams

Flow Diagram:
Steam Generator and Associated Pollution Control Equipment



Process Flow Diagrams





ML-12-CH-FN-70006-1 (EXHAUST FAN FIRST FLOOR EL. 722')
ML-12-CH-FN-70006-2 (EXHAUST FAN SECOND FLOOR EL. 754')
ML-12-CH-FN-70006-3 (EXHAUST FAN THIRD FLOOR EL. 772')
ML-12-CH-WL-70005-1 (WALL LOUVER FIRST FLOOR EL. 722')
ML-12-CH-WL-70005-2 (WALL LOUVER SECOND FLOOR EL. 754')
ML-12-CH-WL-70005-3 (WALL LOUVER THIRD FLOOR EL. 772')

AMERICAN ELECTRIC POWER
MITCHELL PLANT UNIT 1 & 2
CRESAP, WV.
COAL BLENDING SYSTEM
PARSONS E & C SPECIFICATION AEPM-0-SP-092603
AEP P.O. 849133X181

DATE	No.	REVISION	BY
9-23-06	3	REVISED HOIST TAG NUMBERS	JLB
4/20/06	2	CORRECTED CALL OUTS ADDED HOIST NOTE	JLB
2/28/06	1	ADDED EQUIPMENT TAG NOS.	JLB
12/21/05	0	ISSUED FOR CONSTRUCTION	JLB
11/7/05	A	ISSUED FOR CLIENT REVIEW	JLB

RECORD	DATE
TO APPROVAL	11-7-05
TO SHOP	.
TO FIELD	.
DWN. BY: GLS	06/28/05
CHK. BY: JLB	9/15/05
APP. BY: .	

JOB NO. 05-7680

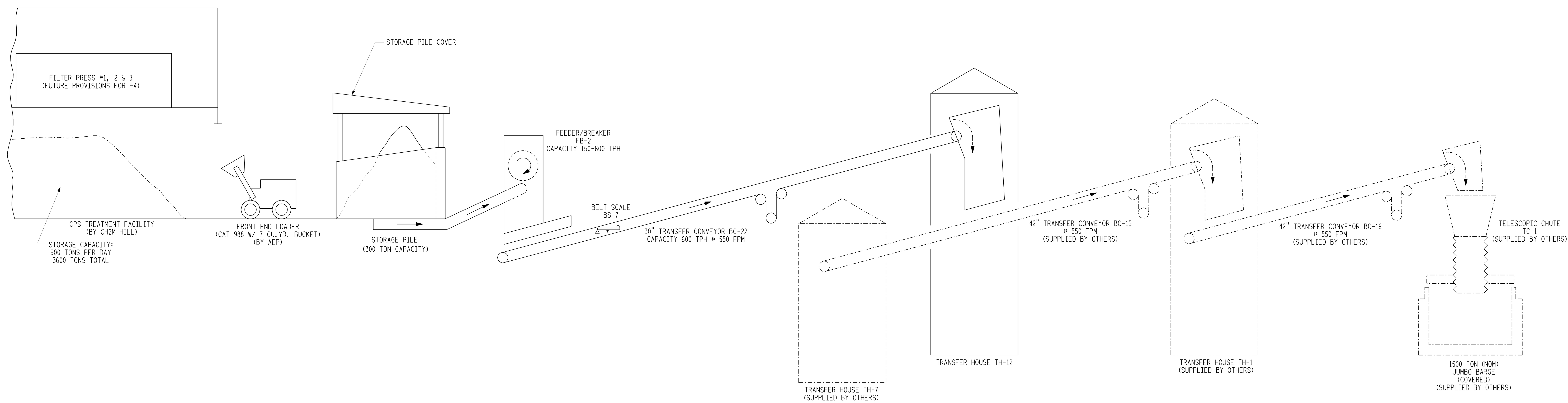
DMW
DEARBORN MID-WEST CONVEYOR CO.

FLOW DIAGRAM
MITCHELL PLANT UNITS 1 & 2 – COAL BLENDING SYSTEM

SCALE NONE | DWG. NO. L-002 | REV. NO. 3

FILE NAME: G:\0521\L-002.dwg
PLOTTED: (JLB) 23-SEP-2006 10:59
PLOT SCALE:

DWG. NO. AEPM-12-SK-ZU-302-004



REVISED STORAGE PILE COVER
ISSUED FOR PERMITTING

REV	DATE	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER/ TECH SPEC	LEAD DISC ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
B	01/20/06	CH			TDH	SGW	JFW	CWS
A	12/22/05	MT			TDH	SGW	JFW	CWS

ISSUED FOR PERMITTING

DATE	NO.	DESCRIPTION	APPD.

REVISIONS

PARSONS E&C

PRELIMINARY STATUS — DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
LDE SG WAINWRIGHT 12-22-05

APPROVED STATUS — DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
LDE

ORIGINATING PERSONNEL	PROFESSIONAL ENGINEER'S SEAL
DRAWN BY MT	
CHECKED BY	
LEAD DESIGNER CC HAGEMEYER	
ENGINEER/TECH SPECIALIST T HAUSCHILD	
PROJECT ENGINEERING MANAGER JF WAGNER	
PROJECT MANAGER CW SAMUELSON	ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE:____ STATE:____ LIC. NO.:____ DATE:____

OHIO POWER COMPANY
MITCHELL PLANT
CRESAP WEST VIRGINIA

FLOW DIAGRAM
CHLORIDE PURGE STREAM
FILTER CAKE HANDLING

DWG. NO. AEPM-12-SK-QW-302-001-B

SCALE: NONE
DR: JG
CH:
DATE:
APPROVED BY

DOCUMENT PREPARED BY PARSONS E&C

AMERICAN ELECTRIC POWER

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

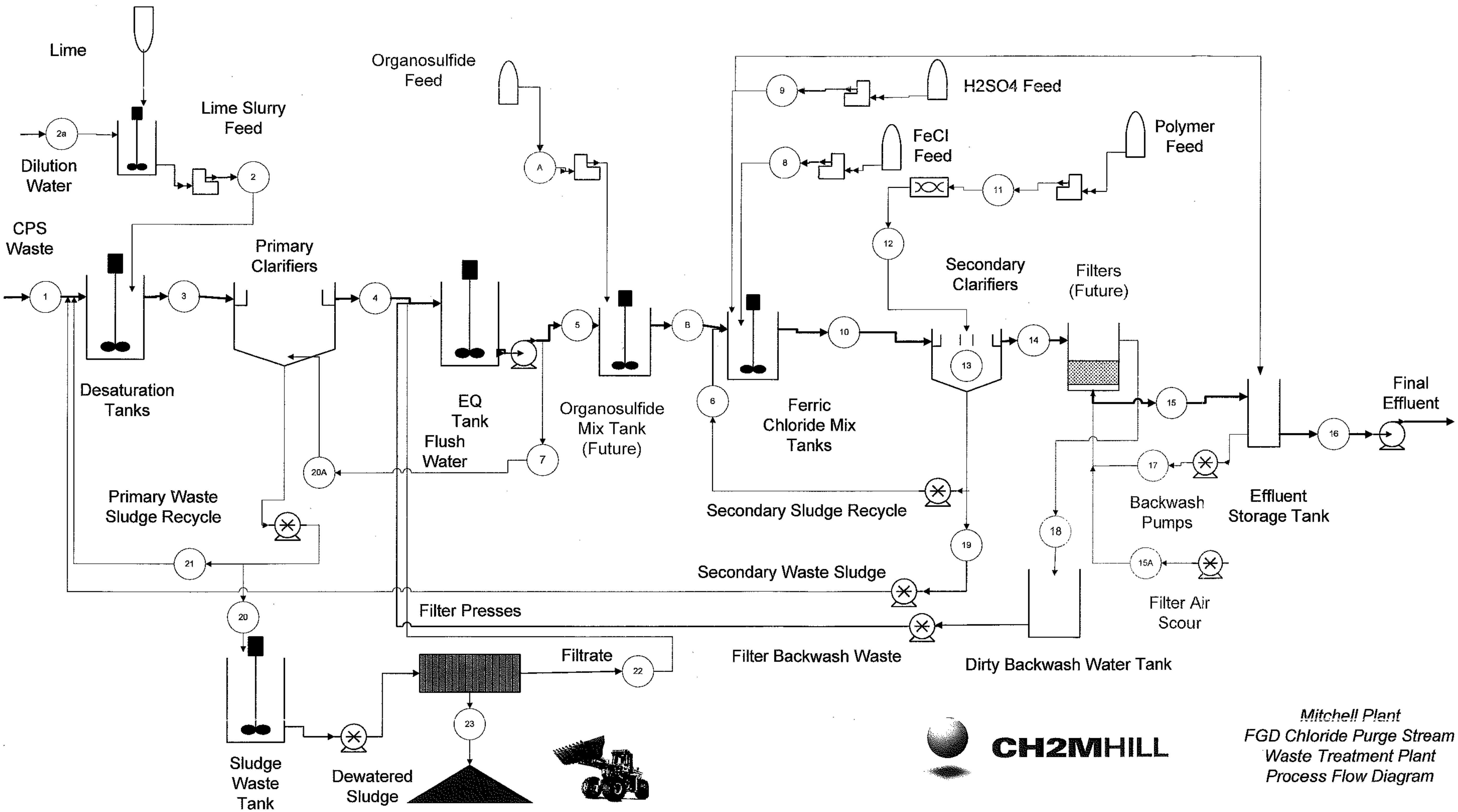
IGS0694

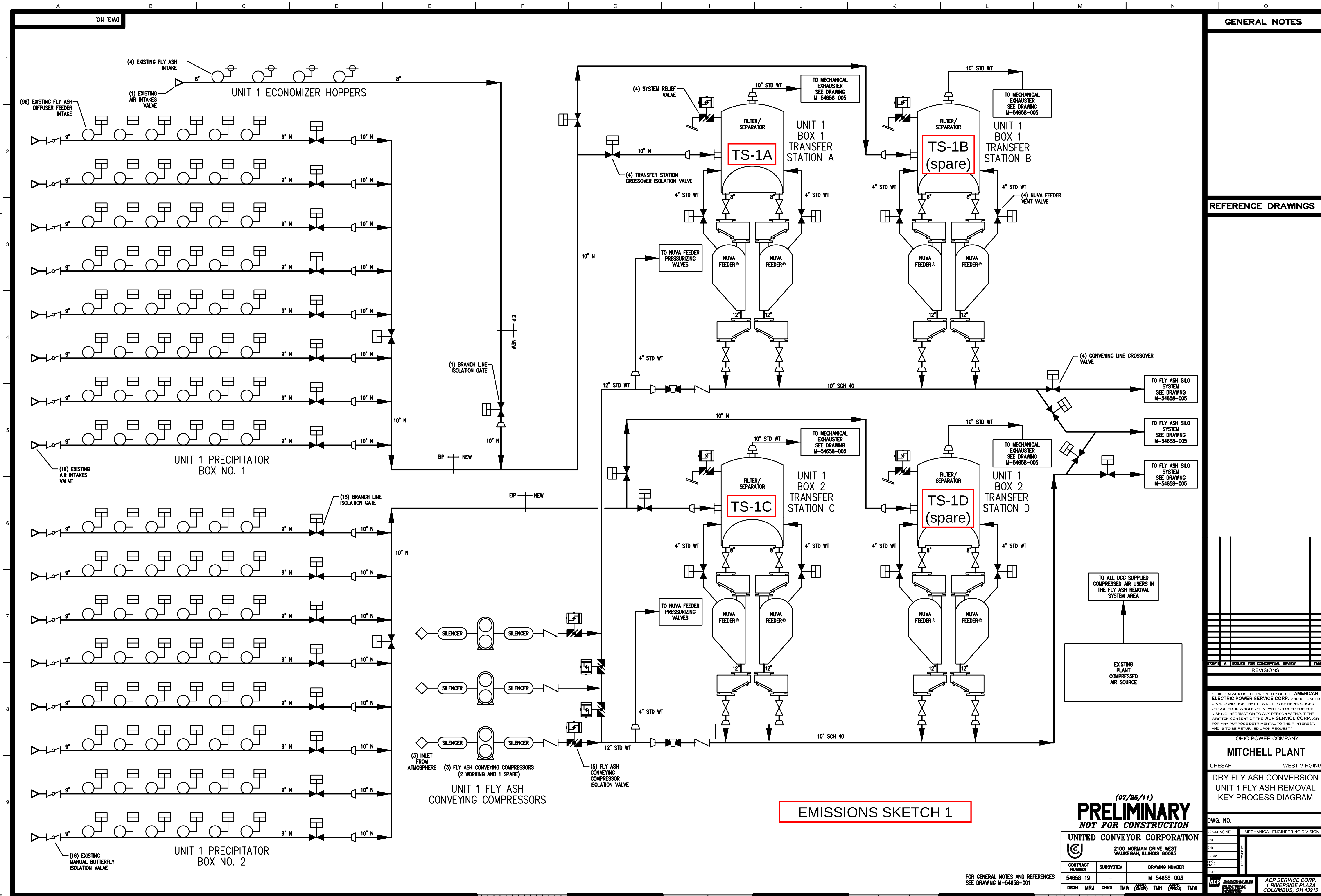
PE&C-FILE: aepmG3d.sed
PE&C-DATE: 04-Mar-04 07:55

SYSTEM DATE-DD-MMM-YYYY
SYSTEM TIME-HOUR:MINUTE

000034

Attachment 1. FGD CPS Wastewater Treatment System Process Flow Diagram




DWG. NO.
(4) EXISTING FLY ASH INTAKE
(1) EXISTING AIR INTAKES VALVE
UNIT 1 ECONOMIZER HOPPERS
(96) EXISTING FLY ASH DIFFUSER FEEDER INTAKE
UNIT 1 PRECIPITATOR BOX NO. 1
(16) EXISTING AIR INTAKES VALVE
(1) BRANCH LINE ISOLATION GATE
(18) BRANCH LINE ISOLATION GATE
UNIT 1 PRECIPITATOR BOX NO. 2
(16) EXISTING MANUAL BUTTERFLY ISOLATION VALVE
(4) SYSTEM RELIEF VALVE
(4) TRANSFER STATION CROSSOVER ISOLATION VALVE
TO MECHANICAL EXHAUSTER SEE DRAWING M-54658-005
FILTER/ SEPARATOR
UNIT 1 BOX 1 TRANSFER STATION A
TS-1A
UNIT 1 BOX 1 TRANSFER STATION B
TS-1B (spare)
(4) NUVA FEEDER VENT VALVE
TO NUVA FEEDER PRESSURIZING VALVES
NUVA FEEDER®
UNIT 1 BOX 2 TRANSFER STATION C
TS-1C
UNIT 1 BOX 2 TRANSFER STATION D
TS-1D (spare)
(4) CONVEYING LINE CROSSOVER VALVE
TO FLY ASH SILO SYSTEM SEE DRAWING M-54658-005
TO ALL UCC SUPPLIED COMPRESSED AIR USERS IN THE FLY ASH REMOVAL SYSTEM AREA
EXISTING PLANT COMPRESSED AIR SOURCE
SILENCER
(3) INLET FROM ATMOSPHERE
(3) FLY ASH CONVEYING COMPRESSORS (2 WORKING AND 1 SPARE)
UNIT 1 FLY ASH CONVEYING COMPRESSORS
(5) FLY ASH CONVEYING COMPRESSOR ISOLATION VALVE
10" SCH 40
12" STD WT
4" STD WT
10" STD WT
EMISSIONS SKETCH 1
GENERAL NOTES
REFERENCE DRAWINGS
A ISSUED FOR CONCEPTUAL REVIEW
REVISIONS
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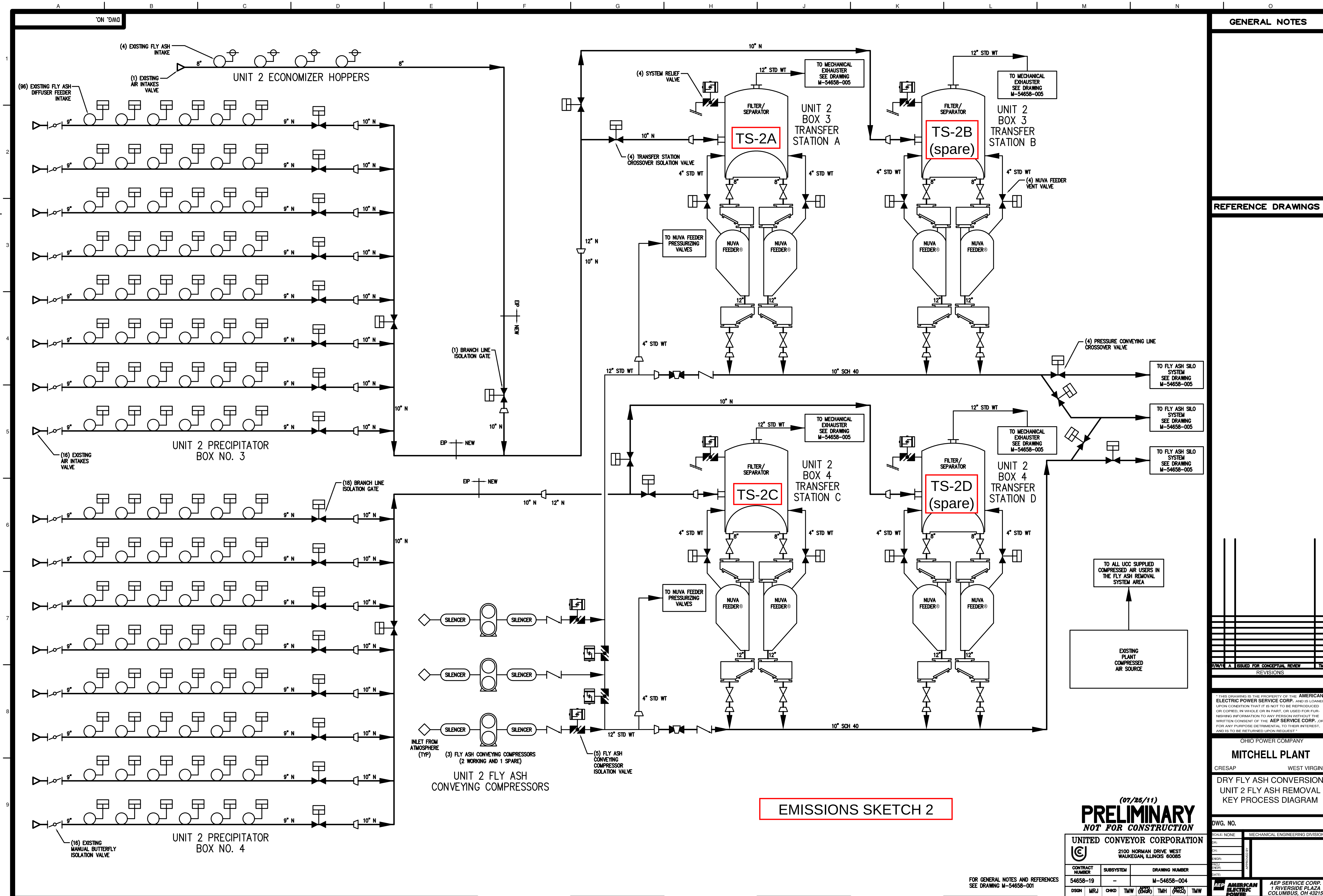
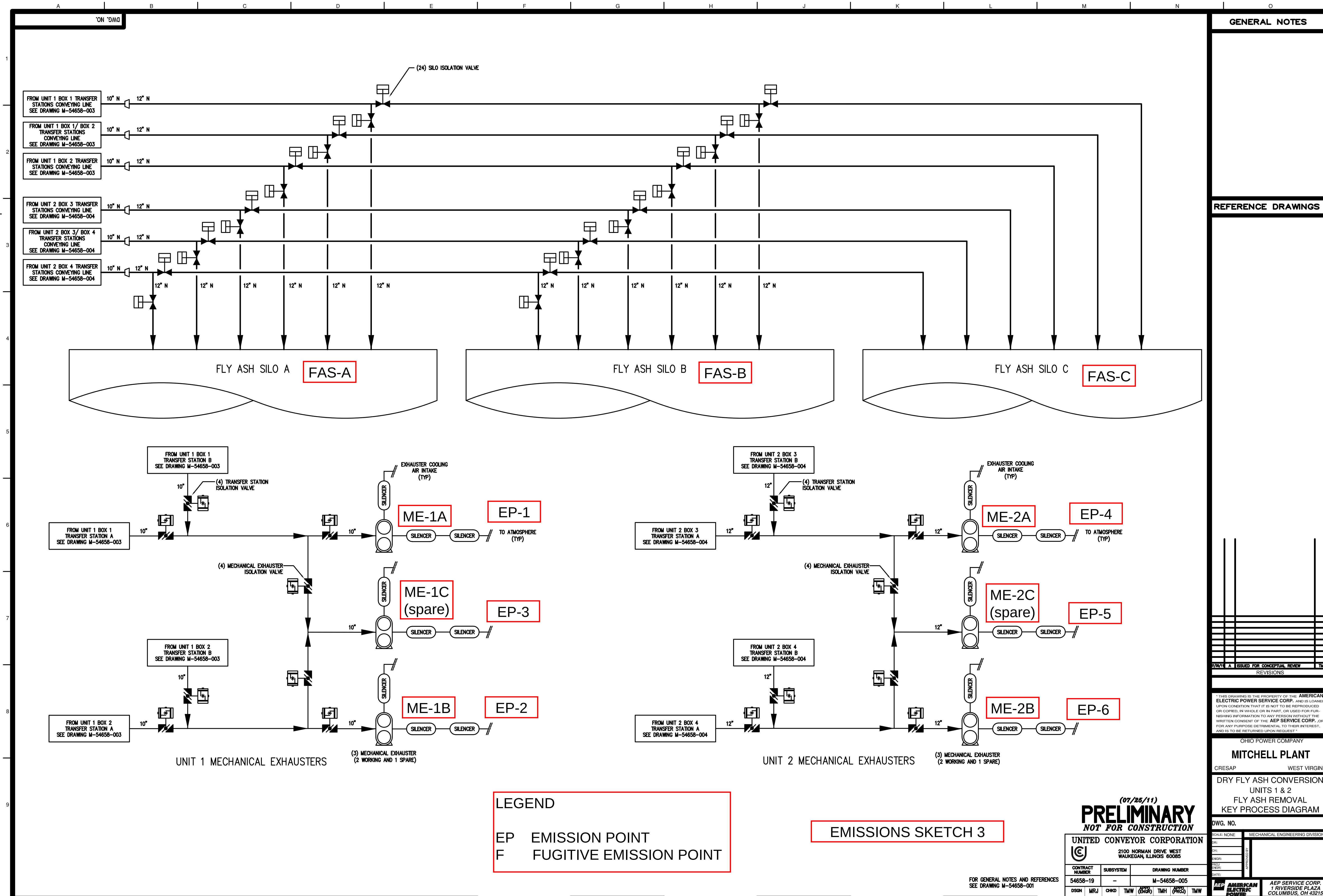
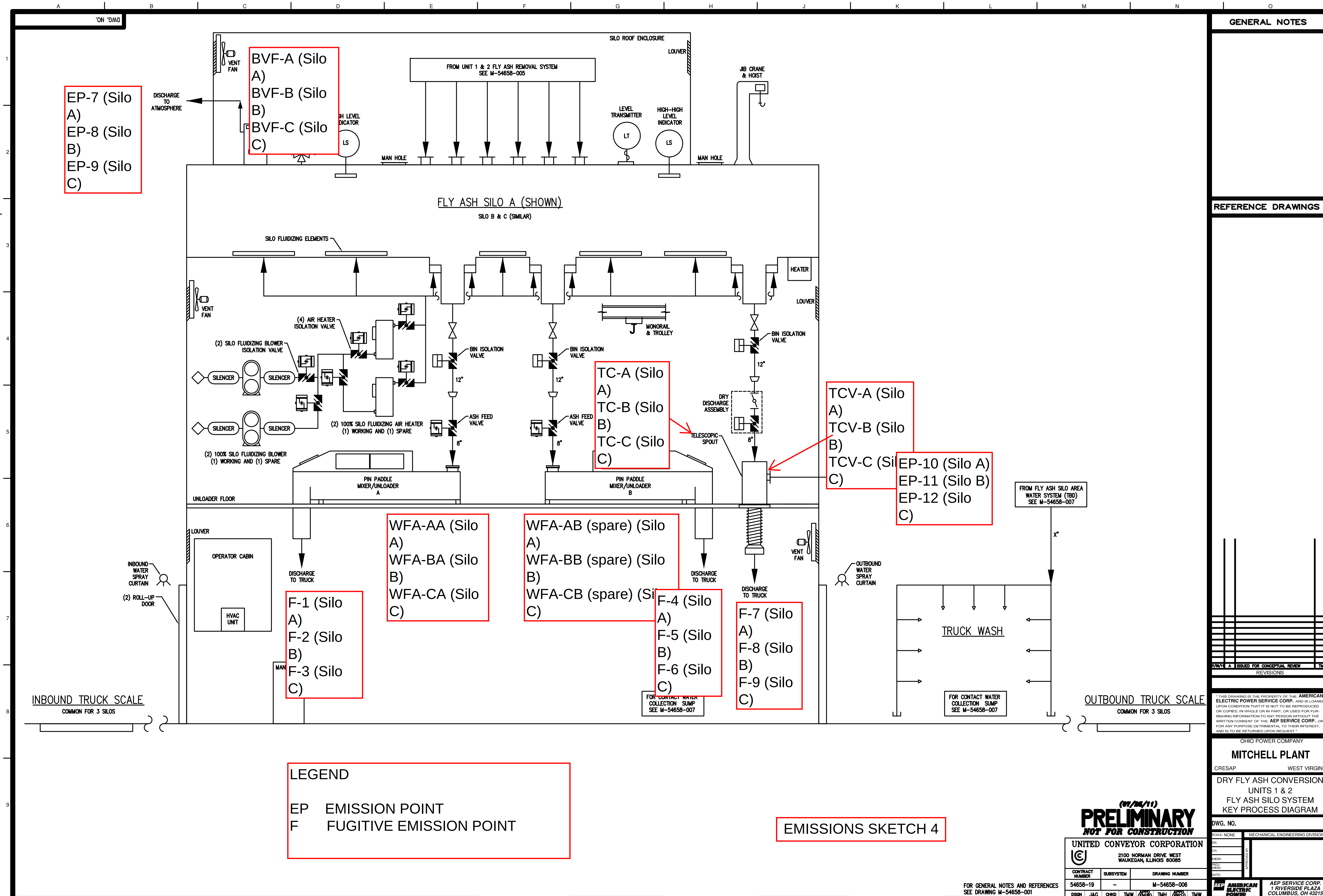
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP WEST VIRGINIA
DRY FLY ASH CONVERSION UNIT 1 FLY ASH REMOVAL KEY PROCESS DIAGRAM
(07/25/11)
PRELIMINARY NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST WAUKEGAN, ILLINOIS 60085
CONTRACT NUMBER 54658-19
DRAWING NUMBER M-54658-003
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
MECHANICAL ENGINEERING DIVISION
AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

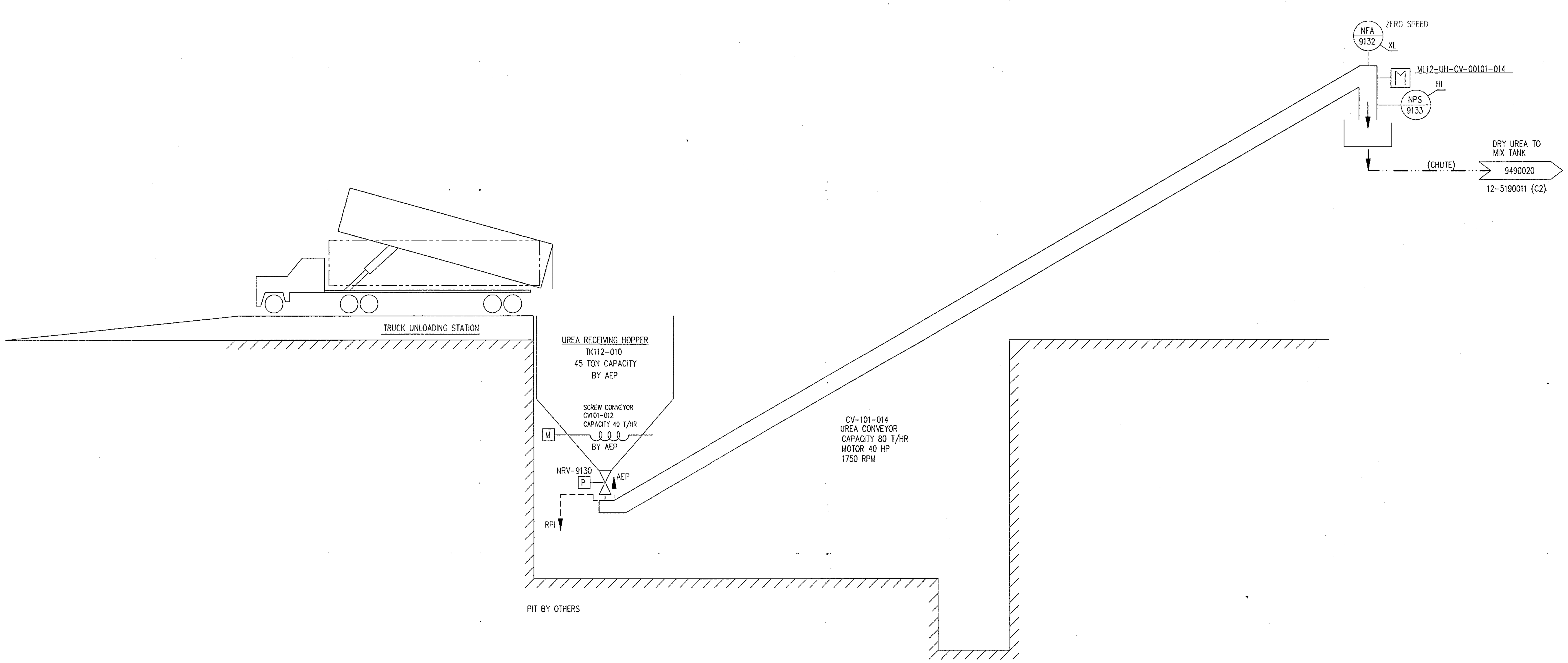

GENERAL NOTES
REFERENCE DRAWINGS
UNIT 2 ECONOMIZER HOPPERS
(4) EXISTING FLY ASH INTAKE
(1) EXISTING AIR INTAKES VALVE
(96) EXISTING FLY ASH DIFFUSER FEEDER INTAKE
UNIT 2 PRECIPITATOR BOX NO. 3
UNIT 2 PRECIPITATOR BOX NO. 4
(18) EXISTING AIR INTAKES VALVE
(18) EXISTING MANUAL BUTTERFLY ISOLATION VALVE
(18) BRANCH LINE ISOLATION GATE
(1) BRANCH LINE ISOLATION GATE
(4) SYSTEM RELIEF VALVE
(4) TRANSFER STATION CROSSOVER ISOLATION VALVE
(4) NUVA FEEDER VENT VALVE
(4) PRESSURE CONVEYING LINE CROSSOVER VALVE
TO MECHANICAL EXHAUSTER SEE DRAWING M-54658-005
TO NUVA FEEDER PRESSURIZING VALVES
FILTER/ SEPARATOR
NUVA FEEDER®
UNIT 2 BOX 3 TRANSFER STATION A
TS-2A
UNIT 2 BOX 3 TRANSFER STATION B
TS-2B (spare)
UNIT 2 BOX 4 TRANSFER STATION C
TS-2C
UNIT 2 BOX 4 TRANSFER STATION D
TS-2D (spare)
TO FLY ASH SILO SYSTEM SEE DRAWING M-54658-005
TO FLY ASH REMOVAL SYSTEM SEE DRAWING M-54658-005
TO ALL UCC SUPPLIED COMPRESSED AIR USERS IN THE FLY ASH REMOVAL SYSTEM AREA
EXISTING PLANT COMPRESSED AIR SOURCE
SILENCER
INLET FROM ATMOSPHERE (TYP)
(3) FLY ASH CONVEYING COMPRESSORS (2 WORKING AND 1 SPARE)
(5) FLY ASH CONVEYING COMPRESSOR ISOLATION VALVE
UNIT 2 FLY ASH CONVEYING COMPRESSORS
10" SCH 40
12" STD WT
4" STD WT
EMISSIONS SKETCH 2
(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST
WAUKEGAN, ILLINOIS 60085
CONTRACT NUMBER 54658-19
DRAWING NUMBER M-54658-004
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
ISSUED FOR CONCEPTUAL REVIEW
REVISIONS
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNIT 2 FLY ASH REMOVAL
KEY PROCESS DIAGRAM
DWG. NO.
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215


GENERAL NOTES
REFERENCE DRAWINGS
(24) SILO ISOLATION VALVE
FROM UNIT 1 BOX 1 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-003
FROM UNIT 1 BOX 1/ BOX 2 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-003
FROM UNIT 1 BOX 2 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-003
FROM UNIT 2 BOX 3 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-004
FROM UNIT 2 BOX 3/ BOX 4 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-004
FROM UNIT 2 BOX 4 TRANSFER STATIONS CONVEYING LINE SEE DRAWING M-54658-004
FLY ASH SILO A
FAS-A
FLY ASH SILO B
FAS-B
FLY ASH SILO C
FAS-C
FROM UNIT 1 BOX 1 TRANSFER STATION B SEE DRAWING M-54658-003
(4) TRANSFER STATION ISOLATION VALVE
FROM UNIT 1 BOX 1 TRANSFER STATION A SEE DRAWING M-54658-003
EXHAUSTER COOLING AIR INTAKE (TYP)
SILENCER
ME-1A
EP-1
TO ATMOSPHERE (TYP)
(4) MECHANICAL EXHAUSTER ISOLATION VALVE
ME-1C (spare)
EP-3
FROM UNIT 1 BOX 2 TRANSFER STATION B SEE DRAWING M-54658-003
FROM UNIT 1 BOX 2 TRANSFER STATION A SEE DRAWING M-54658-003
ME-1B
EP-2
(3) MECHANICAL EXHAUSTER (2 WORKING AND 1 SPARE)
UNIT 1 MECHANICAL EXHAUSTERS
FROM UNIT 2 BOX 3 TRANSFER STATION B SEE DRAWING M-54658-004
FROM UNIT 2 BOX 3 TRANSFER STATION A SEE DRAWING M-54658-004
ME-2A
EP-4
ME-2C (spare)
EP-5
FROM UNIT 2 BOX 4 TRANSFER STATION B SEE DRAWING M-54658-004
FROM UNIT 2 BOX 4 TRANSFER STATION A SEE DRAWING M-54658-004
ME-2B
EP-6
UNIT 2 MECHANICAL EXHAUSTERS
LEGEND
EP EMISSION POINT
F FUGITIVE EMISSION POINT
EMISSIONS SKETCH 3
(07/25/11)
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST WAUKEGAN, ILLINOIS 60085
54658-19
M-54658-005
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
REVISIONS
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNITS 1 & 2
FLY ASH REMOVAL
KEY PROCESS DIAGRAM
DWG. NO.
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215



DWG. NO.
GENERAL NOTES
REFERENCE DRAWINGS
EP-7 (Silo A)
EP-8 (Silo B)
EP-9 (Silo C)
DISCHARGE TO ATMOSPHERE
VENT FAN
BVF-A (Silo A)
BVF-B (Silo B)
BVF-C (Silo C)
SILO ROOF ENCLOSURE
LOUVER
FROM UNIT 1 & 2 FLY ASH REMOVAL SYSTEM SEE M-54658-005
JIB CRANE & HOIST
LEVEL TRANSMITTER
HIGH-HIGH LEVEL INDICATOR
MAN HOLE
FLY ASH SILO A (SHOWN)
SILO B & C (SIMILAR)
SILO FLUIDIZING ELEMENTS
HEATER
(4) AIR HEATER ISOLATION VALVE
(2) SILO FLUIDIZING BLOWER ISOLATION VALVE
SILENCER
(2) 100% SILO FLUIDIZING AIR HEATER (1) WORKING AND (1) SPARE
(2) 100% SILO FLUIDIZING BLOWER (1) WORKING AND (1) SPARE
BIN ISOLATION VALVE
ASH FEED VALVE
12"
8"
MONORAIL & TROLLEY
TC-A (Silo A)
TC-B (Silo B)
TC-C (Silo C)
DRY DISCHARGE ASSEMBLY
TELESCOPIC SPOUT
TCV-A (Silo A)
TCV-B (Silo B)
TCV-C (Silo C)
EP-10 (Silo A)
EP-11 (Silo B)
EP-12 (Silo C)
PIN PADDLE MIXER/UNLOADER A
PIN PADDLE MIXER/UNLOADER B
UNLOADER FLOOR
FROM FLY ASH SILO AREA WATER SYSTEM (TBD) SEE M-54658-007
OPERATOR CABIN
HVAC UNIT
INBOUND WATER SPRAY CURTAIN
(2) ROLL-UP DOOR
DISCHARGE TO TRUCK
WFA-AA (Silo A)
WFA-BA (Silo B)
WFA-CA (Silo C)
WFA-AB (spare) (Silo A)
WFA-BB (spare) (Silo B)
WFA-CB (spare) (Silo C)
F-1 (Silo A)
F-2 (Silo B)
F-3 (Silo C)
F-4 (Silo A)
F-5 (Silo B)
F-6 (Silo C)
F-7 (Silo A)
F-8 (Silo B)
F-9 (Silo C)
FOR CONTACT WATER COLLECTION SUMP SEE M-54658-007
OUTBOUND WATER SPRAY CURTAIN
TRUCK WASH
INBOUND TRUCK SCALE
COMMON FOR 3 SILOS
OUTBOUND TRUCK SCALE
COMMON FOR 3 SILOS
LEGEND
EP EMISSION POINT
F FUGITIVE EMISSION POINT
EMISSIONS SKETCH 4
PRELIMINARY
NOT FOR CONSTRUCTION
UNITED CONVEYOR CORPORATION
2100 NORMAN DRIVE WEST WAUKEGAN, ILLINOIS 60085
54658-19
M-54658-006
FOR GENERAL NOTES AND REFERENCES SEE DRAWING M-54658-001
ISSUED FOR CONCEPTUAL REVIEW
REVISIONS
OHIO POWER COMPANY
MITCHELL PLANT
CRESAP
WEST VIRGINIA
DRY FLY ASH CONVERSION
UNITS 1 & 2
FLY ASH SILO SYSTEM
KEY PROCESS DIAGRAM
MECHANICAL ENGINEERING DIVISION
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

DWG. NO. 100273-9490010



PARSONS E & C
MITCHELL PLANT

✓ REVIEWED AND ACCEPTED
__ REVIEWED AND ACCEPTED AS NOTED (RESUBMIT FOR RECORD)
__ NOT ACCEPTED (RESUBMIT FOR REVIEW)
__ FOR INFORMATION ONLY (REVIEW WAIVED)

THE REVIEW OF THIS SUBMITTAL IS ONLY FOR GENERAL CONFORMANCE WITH THE DESIGN CONCEPTS OF THE PROJECT AND GENERAL COMPLIANCE WITH THE INFORMATION IN THE CONTRACT. THE SUBMITTAL VENDOR IS FULLY RESPONSIBLE FOR; FULL COMPLIANCE WITH THE PROJECT REQUIREMENTS; FOR DIMENSIONS TO BE CONFORMED AND/OR RELATED AT/TO THE JOBSITE; FOR INFORMATION THAT PERTAINS SOLELY TO THE FABRICATION PROCESS; FOR DESIGNS ORIGINATED BY HIM/HER; FOR TECHNIQUES OF CONSTRUCTION AND; FOR COORDINATION OF THE WORK OF ALL TRADES. SUBMITTAL REVIEW DOES NOT CONSTITUTE A CHANGE ORDER AND DOES NOT ALTER ANY CONTRACT TERMS AND CONDITIONS.

DATE 5/31/06 BY [signature]

03158 - 12-5190010 - - - 1
AEPM-12-DV-094502-
12-5190010-R1(6)

NOTES:

1. DELETED
2. ALL TAG #'S PREFACED WITH ML12 UNLESS OTHERWISE SPECIFIED.

LEGEND

————————	STEAM
– – – – – – – –	AMMONIA VAPOR
—·—··—·—··	DRY UREA

ALTERATION	NO.	BY	CHK	DATE	APP'D	DATE
ISSUE FOR CONSTRUCTION	04	JWL	[illegible]	[illegible]	CAE	[illegible]
ISSUE FOR CONSTRUCTION	03	JWL	BH	05/20/05	CAE	05/20/05
ISSUE FOR APPROVAL	02	JWL	TN	04/30/05	CAE	05/01/05
ISSUE FOR CERTIFICATION	01	JWL	TN	04/12/05	BB	04/12/05

"N" MATERIAL NOT FURNISHED BY
"F" MATERIAL FURNISHED BY
RILEY POWER INC.

THIS DRAWING IS NOT APPROVED FOR CONSTRUCTION UNLESS IT CONTAINS DATE AND SIGNATURE OF APPROVAL AND THE COMPANY RESERVES THE RIGHT TO CORRECT ANY ERRORS OR OMISSIONS PRIOR TO ACTUAL START OF WORK.

CLAYTON ERICKSON — RELEASED & APPROVED — 05/20/05 DATE

DRAWN JWL DATE 03/14/05
CHECKED TN DATE 03/15/05
APP'D RJ DATE 03/15/05

FUNCTIONAL REVIEW / APPROVAL
REVIEWED & APP'D / DATE

DO NOT SCALE
USE DIMENSIONS ONLY
SCALE NTS IN. = 1 FT.
ES W F ER

RILEY POWER INC.

PIPING AND INSTRUMENTATION DIAGRAM
DRY UREA UNLOADING
U2A SYSTEM
MITCHELL PLANT – UNIT #1 & 2
AMERICAN ELECTRIC POWER
CRESAP, WEST VIRGINIA

DWG. NO. 100273-9490010-04

DATE	NO.	DESCRIPTION	APPD.
	1	ISSUE FOR CONSTRUCTION	
	0	ISSUE FOR CONSTRUCTION	

REVISIONS

OHIO POWER COMPANY
MITCHELL PLANT
CRESAP WEST VIRGINIA

FLOW DIAGRAM
DRY UREA HANDLING

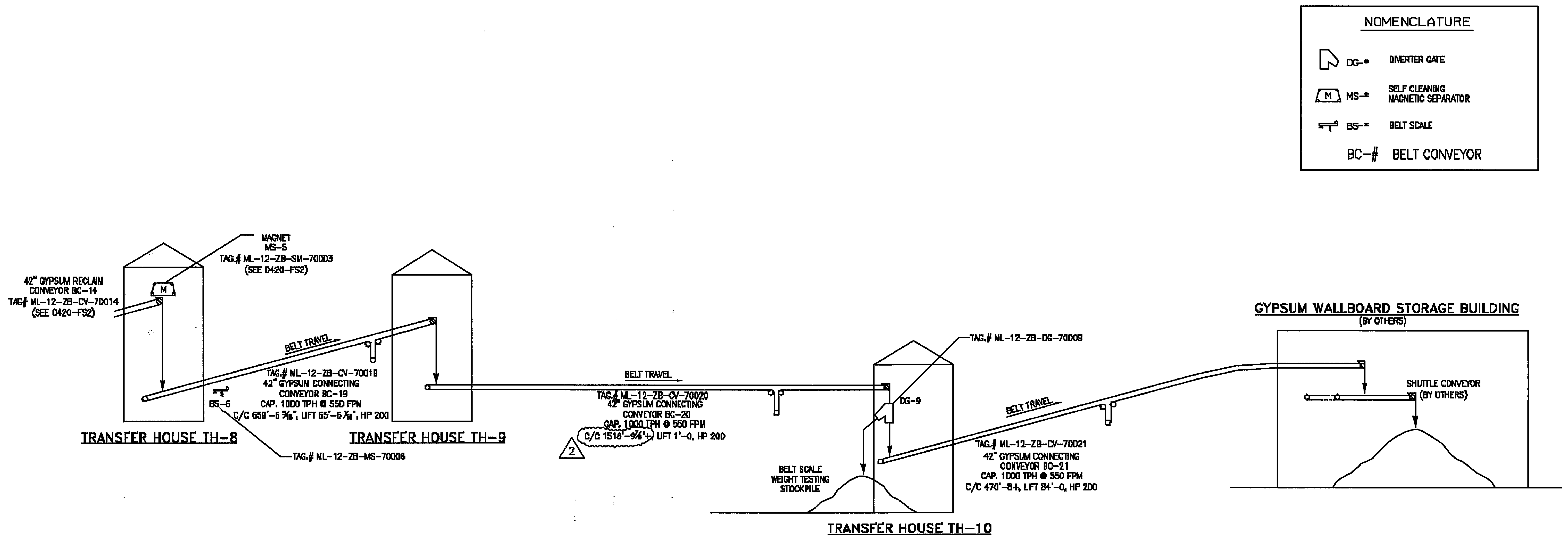
DWG. NO. 12-5190010 - 1

SCALE: none
DR:
CH:
DES SUPV:
ENGR:
DATE:
APPROVED BY

DOCUMENT PREPARED BY RILEY POWER INC.

AMERICAN ELECTRIC POWER

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215



RECEIVED FOR CONSTRUCTION

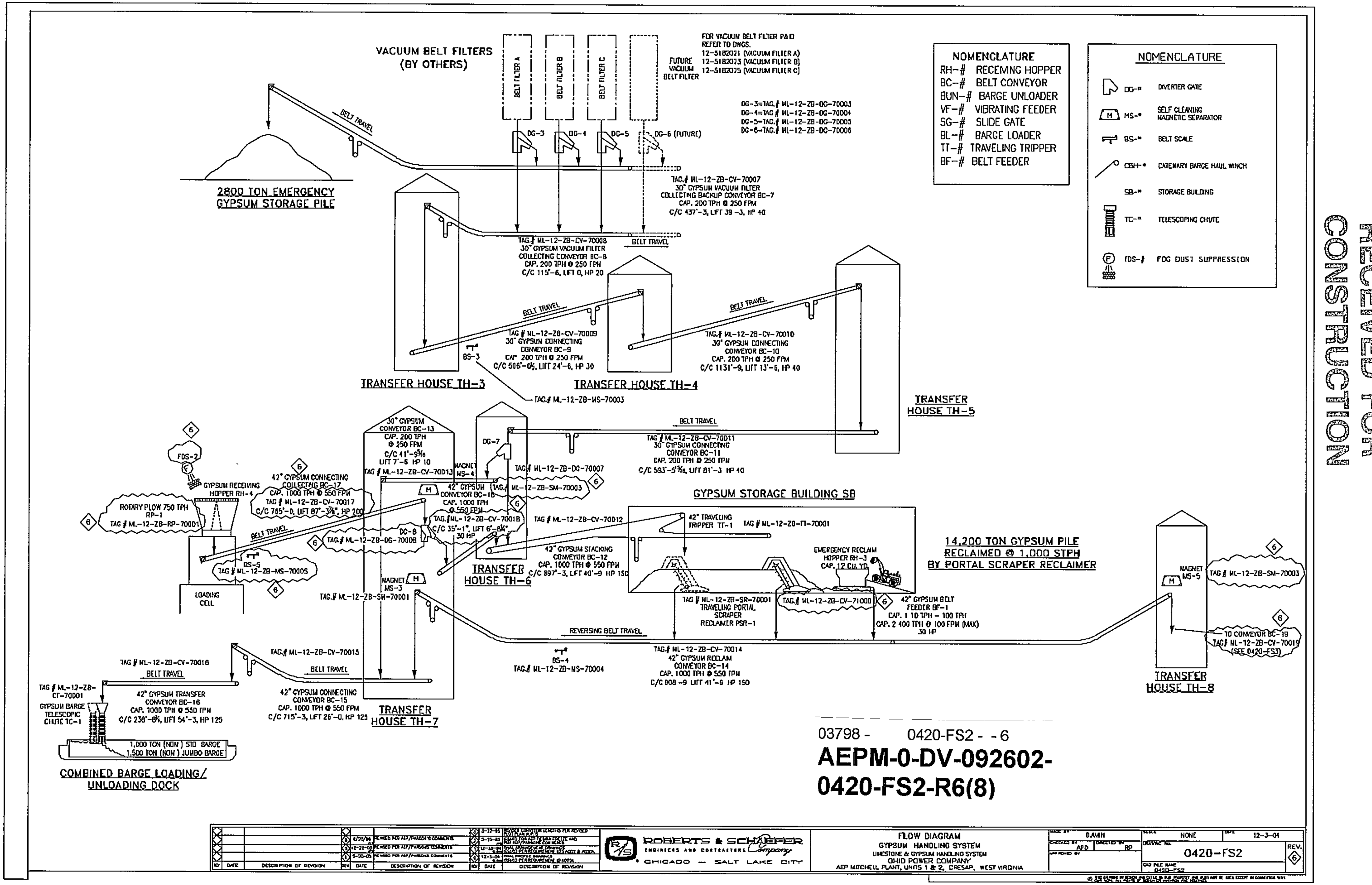
03868 - 0420-FS3 - - - 2
AEPM-0-DV-092604-0420-FS3-R2(3)

REV.	DATE	DESCRIPTION OF REVISION
	9/12/06	REVISED PER CUSTOMER'S COMMENTS
	6/25/06	REVISED PER AEP/PARSON'S COMMENTS
	12-22-05	ISSUED FOR APPROVAL

ROBERTS & SCHAEFER Company
ENGINEERS AND CONTRACTORS
CHICAGO — SALT LAKE CITY

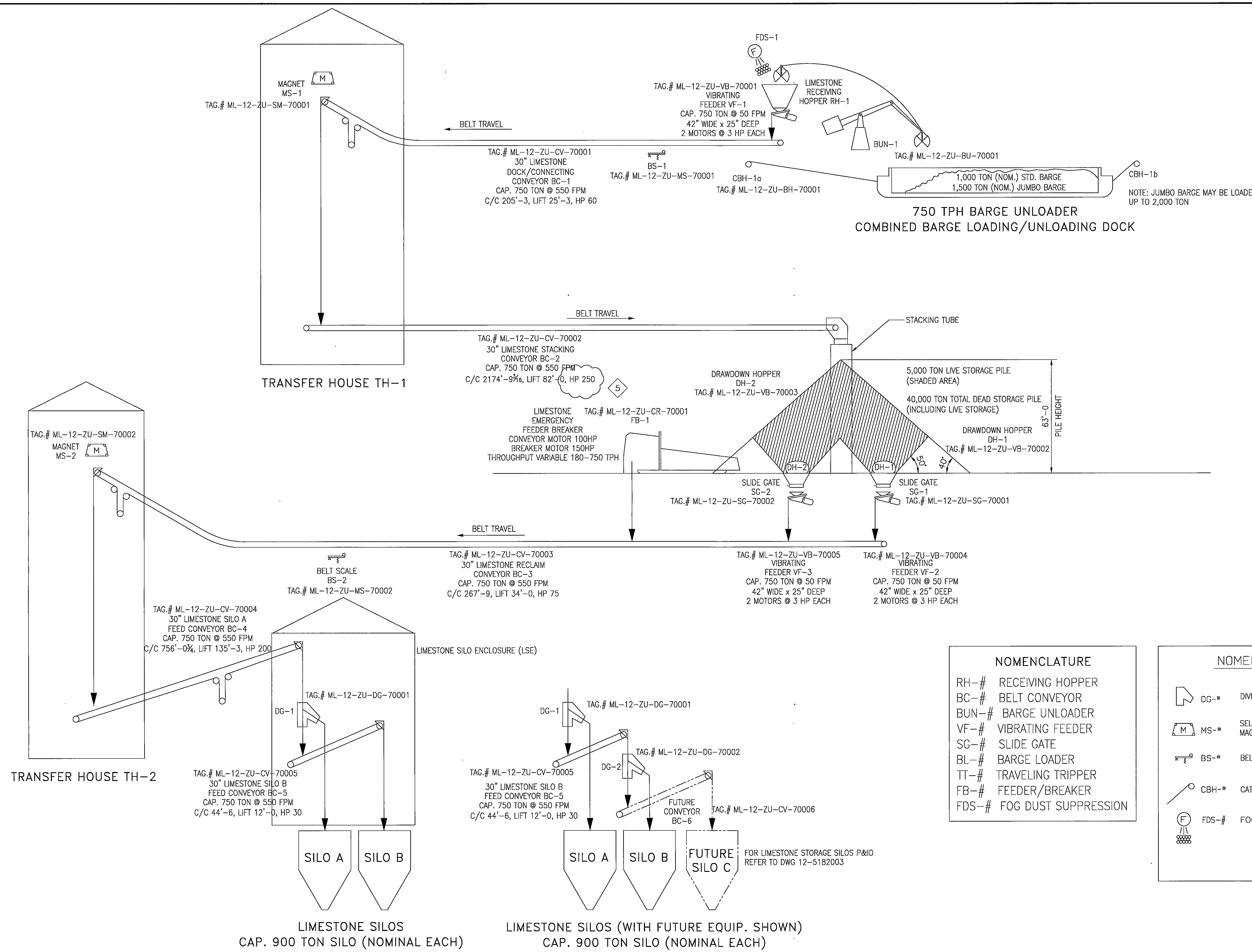
FLOW DIAGRAM
GYPSUM HANDLING SYSTEM
LIMESTONE & GYPSUM HANDLING SYSTEM
OHIO POWER COMPANY
AEP MITCHELL PLANT, UNITS 1 & 2, CRESAP, WEST VIRGINIA

MADE BY	A DYDCO
CHECKED BY	PJP
CREATED BY	B TURNEY
APPROVED BY	
SCALE	NONE
DATE	12-27-05
DRAWING No.	0420-FS3
REV.	2
CAD FILE NAME	0420-FS3



03798 - 0420-FS2 - - 6

AEPM-0-DV-092602-0420-FS2-R6(8)



NOMENCLATURE

RH-#	RECEIVING HOPPER
BC-#	BELT CONVEYOR
BUN-#	BARGE UNLOADER
VF-#	VIBRATING FEEDER
SG-#	SLIDE GATE
BL-#	BARGE LOADER
TT-#	TRAVELING TRIPPER
FB-#	FEEDER/BREAKER
FDS-#	FOG DUST SUPPRESSION

NOMENCLATURE

DG-#	DIVERTER GATE
MS-#	SELF CLEANING MAGNETIC SEPARATOR
BS-#	BELT SCALE
CBH-#	CATENARY BARGE HAUL WINCH
FDS-#	FOG DUST SUPPRESSION

02215 - 0420-FS1 - - 5

AEPM-0-DV-092602-0420-FS1-R5(8)

PARSONS E & C
MITCHELL PLANT

X REVIEWED AND ACCEPTED
___ REVIEWED AND ACCEPTED AS NOTED (RESUBMIT FOR RECORD)
___ NOT ACCEPTED (RESUBMIT FOR REVIEW)
___ FOR INFORMATION ONLY (REVIEW WAIVED)

THE REVIEW OF THIS SUBMITTAL IS ONLY FOR GENERAL CONFORMANCE WITH THE DESIGN CONCEPTS OF THE PROJECT AND GENERAL COMPLIANCE WITH THE INFORMATION IN THE CONTRACT THE SUBMITTAL VENDOR IS FULLY RESPONSIBLE FOR; FULL COMPLIANCE WITH THE PROJECT REQUIREMENTS; FOR DIMENSIONS TO BE CONFORMED AND/OR RELATED AT/TO THE JOBSITE; FOR INFORMATION THAT PERTAINS SOLELY TO THE FABRICATION PROCESS; FOR DESIGNS ORIGINATED BY HIM/HER, FOR TECHNIQUES OF CONSTRUCTION AND; FOR COORDINATION OF THE WORK OF ALL TRADES. SUBMITTAL REVIEW DOES NOT CONSTITUTE A CHANGE ORDER AND DOES NOT ALTER ANY CONTRACT TERMS AND CONDITIONS.

DATE 12/9/05 BY [signature]

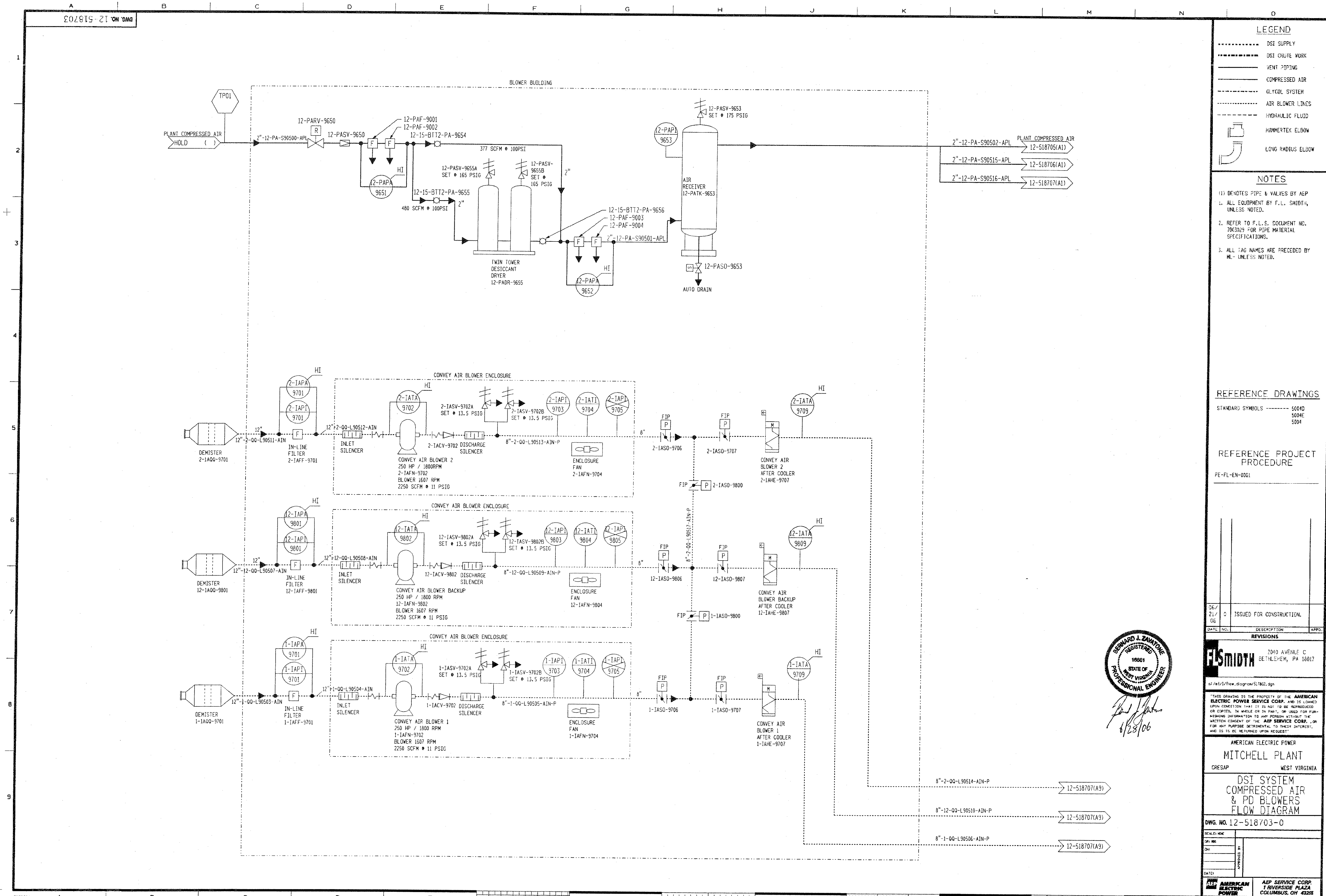
REV	DATE	DESCRIPTION OF REVISION
5	10-28-05	REVISED PER AEP/PARSONS COMMENTS
4	5-20-05	REVISED PER AEP/PARSONS COMMENTS ADDED BREAKER INFO
3	3-22-05	REVISED VIBRATING FEEDER & DRAWDOWN HOPPER TAG NUMBERS
2	2-25-05	ISSUED FOR AEP DESIGN FREEZE AND PER AEP/PARSONS COMMENTS
1	12-28-04	FINAL ARRANGEMENT DRAWINGS ISSUED PER REQUIREMENT ID'S A002 & A030A
0	12-3-04	FINAL PROFILE DRAWINGS ISSUED PER REQUIREMENT ID A003A

ROBERTS & SCHAEFER Company
ENGINEERS AND CONTRACTORS
CHICAGO — SALT LAKE CITY

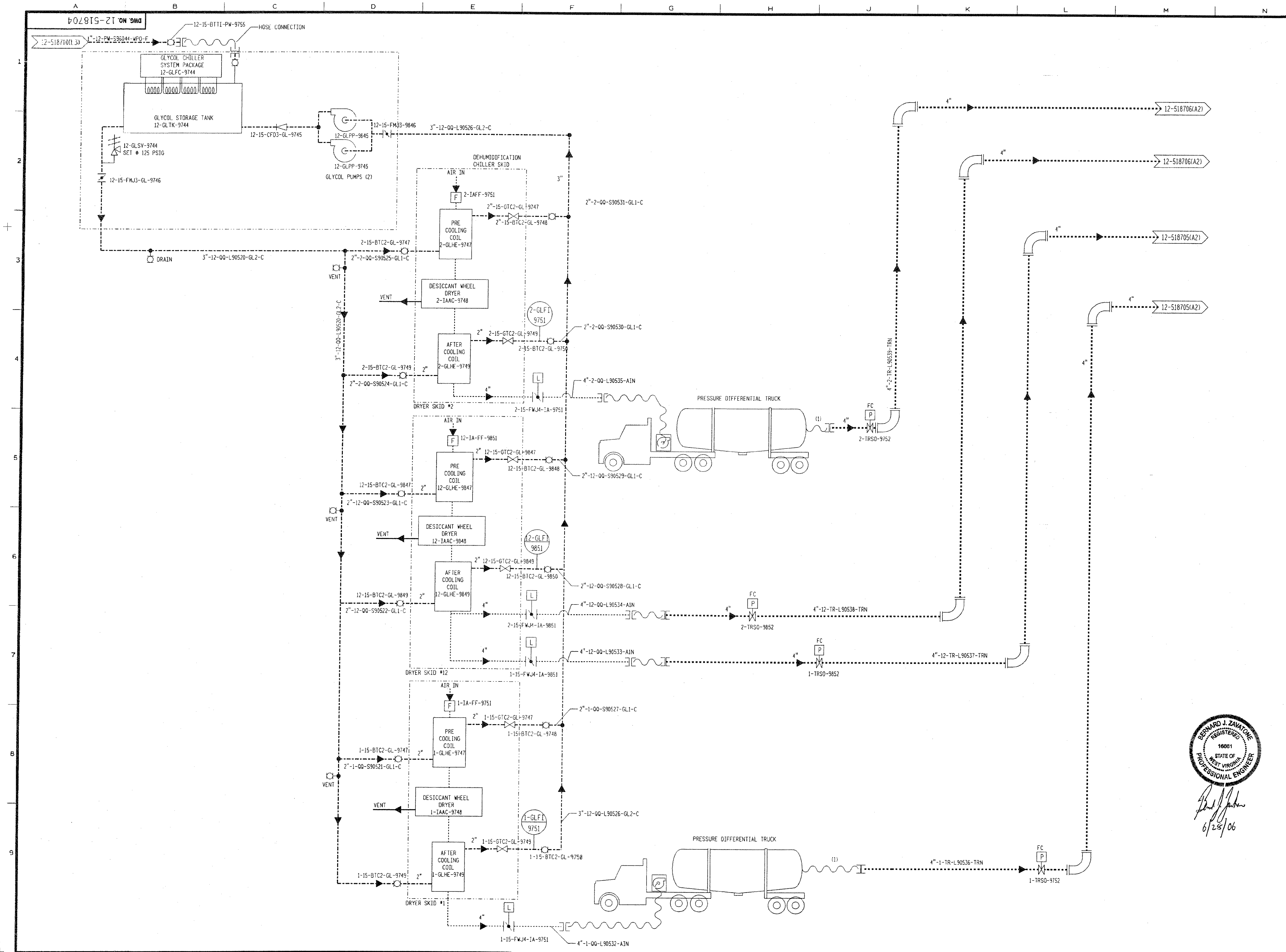
FLOW DIAGRAM
LIMESTONE HANDLING SYSTEM
LIMESTONE & GYPSUM HANDLING SYSTEM
OHIO POWER COMPANY
AEP MITCHELL PLANT, UNITS 1 & 2, CRESAP, WEST VIRGINIA

MADE BY	D.AMIN
CHECKED BY	APD
DIRECTED BY	RP
APPROVED BY	
SCALE	NONE
DATE	12-3-04
DRAWING No	**0420-FS1**
REV	5
CAD FILE NAME	0420-FS1

41



DWG. NO. 12-518703
BLOWER BUILDING
TP01
PLANT COMPRESSED AIR
HOLD
2"-12-PA-S90500-APL
12-PARV-9650
12-PASV-9650
12-PAF-9001
12-PAF-9002
12-15-BTT2-PA-9654
377 SCFM @ 100PSI
12-PAPA 9651
12-15-BTT2-PA-9655
480 SCFM @ 100PSI
12-PASV-9655A SET @ 165 PSIG
12-PASV-9655B SET @ 165 PSIG
TWIN TOWER DESICCANT DRYER 12-PADR-9655
12-15-BTT2-PA-9656
12-PAF-9003
12-PAF-9004
2"-12-PA-S90501-APL
12-PAPA 9652
12-PASV-9653 SET @ 175 PSIG
12-PAPI 9653
AIR RECEIVER 12-PATK-9653
12-PASO-9653
AUTO DRAIN
2"-12-PA-S90502-APL
2"-12-PA-S90515-APL
2"-12-PA-S90516-APL
12-518705(A1)
12-518706(A1)
12-518707(A1)
CONVEY AIR BLOWER ENCLOSURE
DEMISTER 2-IAQQ-9701
IN-LINE FILTER 2-IAFF-9701
12"-2-QQ-L90511-AIN
12"-2-QQ-L90512-AIN
INLET SILENCER
CONVEY AIR BLOWER 2 250 HP / 1800RPM 2-IAFN-9702 BLOWER 1607 RPM 2250 SCFM @ 11 PSIG
2-IACV-9702
DISCHARGE SILENCER
2-IASV-9702A SET @ 13.5 PSIG
2-IASV-9702B SET @ 13.5 PSIG
8"-2-QQ-L90513-AIN-P
ENCLOSURE FAN 2-IAFN-9704
2-IASO-9706
2-IASO-9707
2-IASO-9800
CONVEY AIR BLOWER 2 AFTER COOLER 2-IAHE-9707
DEMISTER 12-IAQQ-9801
12"-12-QQ-L90507-AIN
IN-LINE FILTER 12-IAFF-9801
12"-12-QQ-L90508-AIN
CONVEY AIR BLOWER BACKUP 250 HP / 1800 RPM 12-IAFN-9802 BLOWER 1607 RPM 2250 SCFM @ 11 PSIG
12-IACV-9802
12-IASV-9802A SET @ 13.5 PSIG
12-IASV-9802B SET @ 13.5 PSIG
8"-12-QQ-L90509-AIN-P
ENCLOSURE FAN 12-IAFN-9804
12-IASO-9806
12-IASO-9807
1-IASO-9800
8"-2-QQ-L90517-AIN-P
CONVEY AIR BLOWER BACKUP AFTER COOLER 12-IAHE-9807
DEMISTER 1-IAQQ-9701
12"-1-QQ-L90503-AIN
IN-LINE FILTER 1-IAFF-9701
12"-1-QQ-L90504-AIN
CONVEY AIR BLOWER 1 250 HP / 1800 RPM 1-IAFN-9702 BLOWER 1607 RPM 2250 SCFM @ 11 PSIG
1-IACV-9702
1-IASV-9702A SET @ 13.5 PSIG
1-IASV-9702B SET @ 13.5 PSIG
8"-1-QQ-L90505-AIN-P
ENCLOSURE FAN 1-IAFN-9704
1-IASO-9706
1-IASO-9707
CONVEY AIR BLOWER 1 AFTER COOLER 1-IAHE-9707
8"-2-QQ-L90514-AIN-P
8"-12-QQ-L90510-AIN-P
8"-1-QQ-L90506-AIN-P
12-518707(A9)
LEGEND
DSI SUPPLY
DSI CHUTE WORK
VENT PIPING
COMPRESSED AIR
GLYCOL SYSTEM
AIR BLOWER LINES
HYDRAULIC FLUID
HAMMERTEK ELBOW
LONG RADIUS ELBOW
NOTES
(1) DENOTES PIPE & VALVES BY AEP
1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7063029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.
REFERENCE DRAWINGS
STANDARD SYMBOLS 5004D 5004E 5004
REFERENCE PROJECT PROCEDURE
PE-FL-EN-0001
06/21/06 0 ISSUED FOR CONSTRUCTION
REVISIONS
BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER
6/28/06
FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017
AMERICAN ELECTRIC POWER
MITCHELL PLANT
CRESAP WEST VIRGINIA
DSI SYSTEM COMPRESSED AIR & PD BLOWERS FLOW DIAGRAM
DWG. NO. 12-518703-0
AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW

NOTES

(1) DENOTES PIPE & VALVES BY AEP
1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D
5004E
5004

REFRENCE PROJECT PROCEDURE

PE-FL-EV-0001

DATE	NO.	DESCRIPTION	APPD.
06/21/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

st/at/1/flow_diagram/518701.dgn

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

AMERICAN ELECTRIC POWER
MITCHELL PLANT
CRESAP WEST VIRGINIA

DSI SYSTEM CHILLER & DEHUMIDIFICATION FLOW DIAGRAM

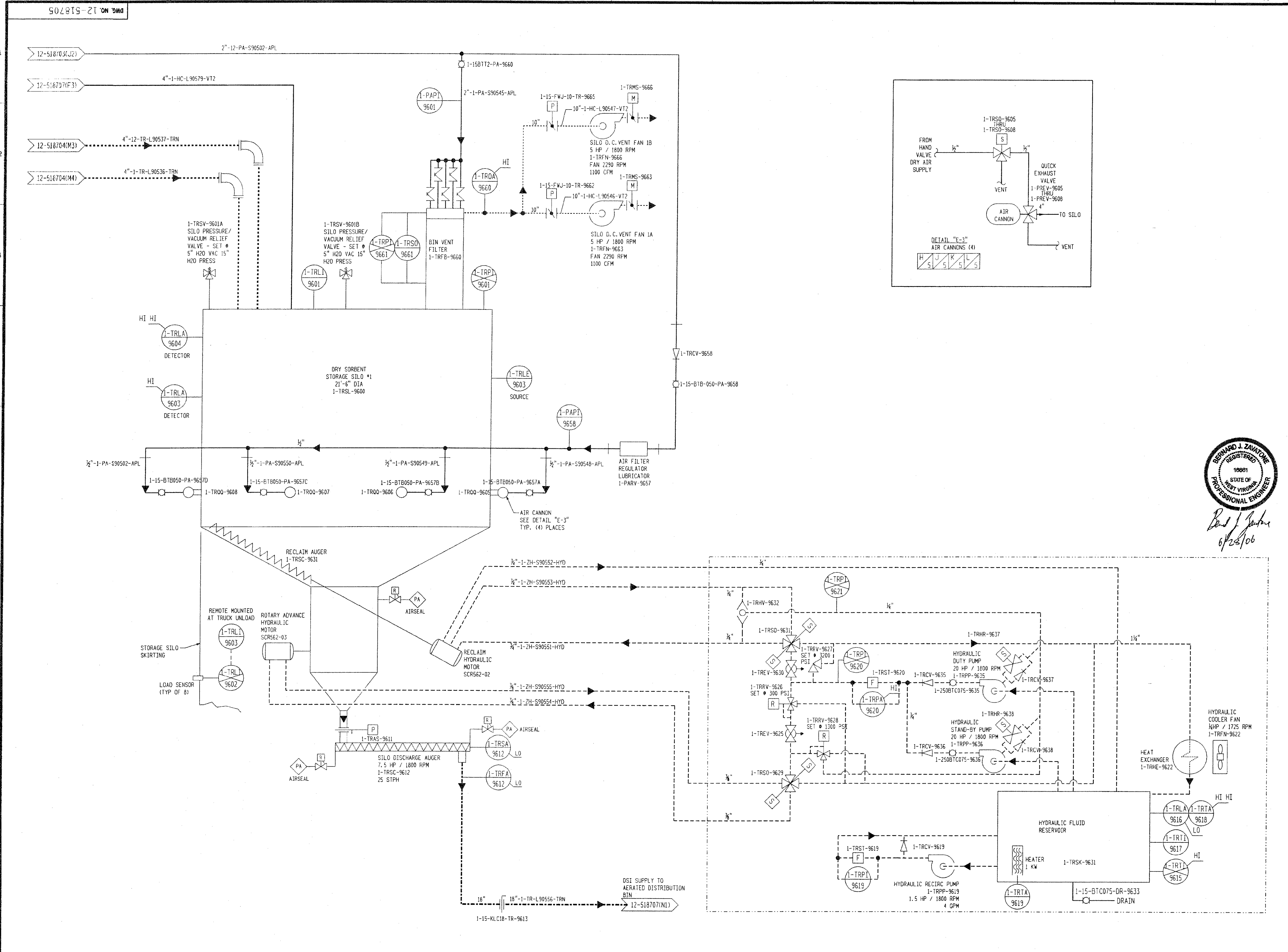
DWG. NO. 12-518704-0

SCALE: NONE
DR: RDS
CH:
DATE:
APPROVED BY

AMERICAN ELECTRIC POWER
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

SYSTEM DATE-6/21/2006
SYSTEM TIME-4:06:57 PM

DWG. NO. 12-518705



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW
- PA — PLANT AIR

NOTES

(I) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D 5004E 5004

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

DATE	NO.	DESCRIPTION	APPD.
05/25/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

s:/mt/1/flow_diagram/518701.dgn

AMERICAN ELECTRIC POWER

MITCHELL PLANT

CRESAP WEST VIRGINIA

DSI SYSTEM SILO 1 & RECLAIM FLOW DIAGRAM

DWG. NO. 12-518705-0

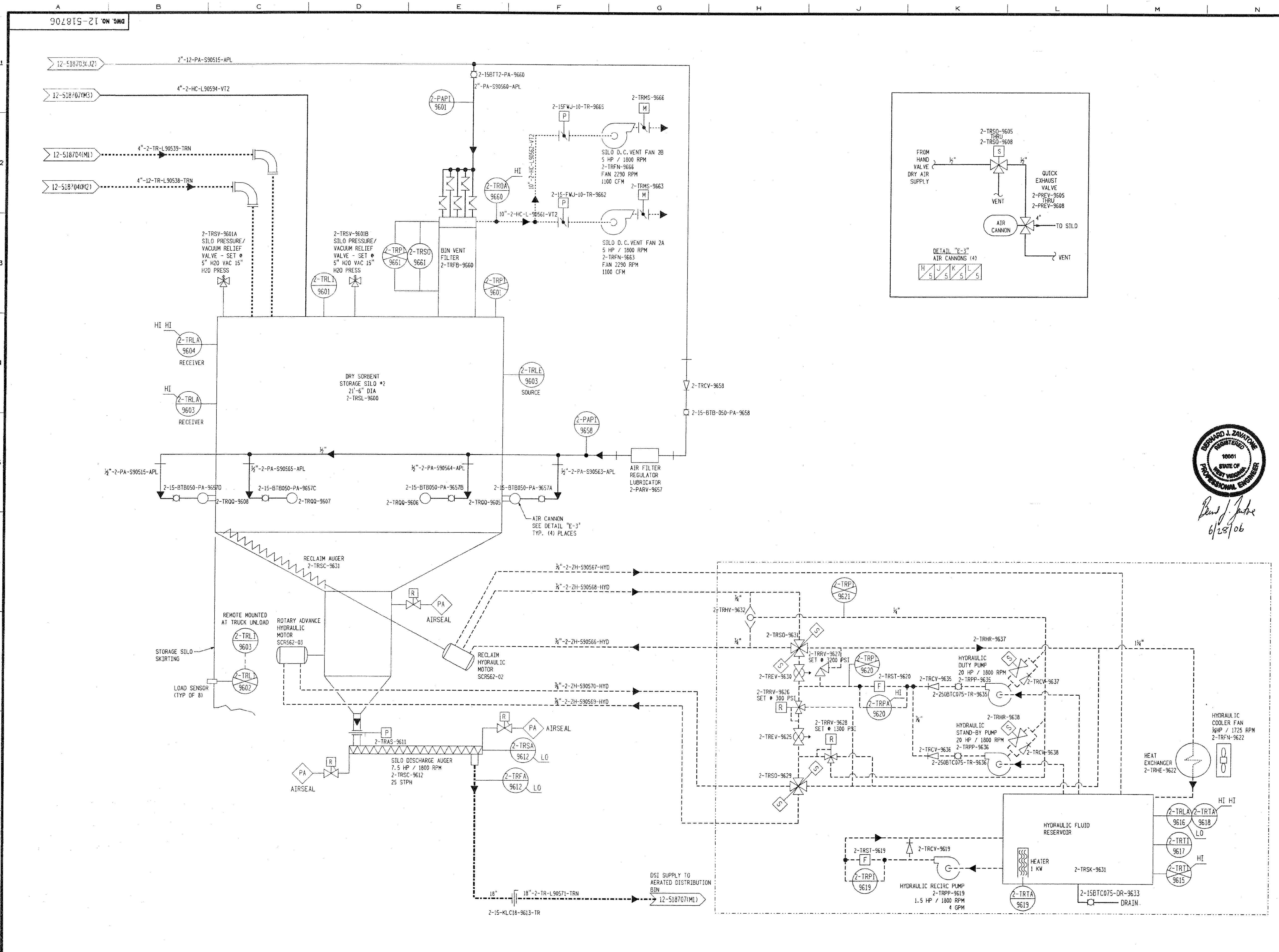
SCALE: NONE
DR: RDS
CH:
DATE:
APPROVED BY

AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

SYSTEM DATE-8/21/2008
SYSTEM TIME-1:07:00 PM

10S0494

DWG. NO. 12-518706



LEGEND

	DSI SUPPLY
	DSI CHUTE WORK
	VENT PIPING
	COMPRESSED AIR
	GLYCOL SYSTEM
	AIR BLOWER LINES
	HYDRAULIC FLUID
	HAMMERTEK ELBOW
	LONG RADIUS ELBOW
PA	PLANT AIR

NOTES

(1) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7303029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS ---------- 5004D 5004E 5004

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

DATE	NO.	DESCRIPTION	APPD.
05/25/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

AMERICAN ELECTRIC POWER

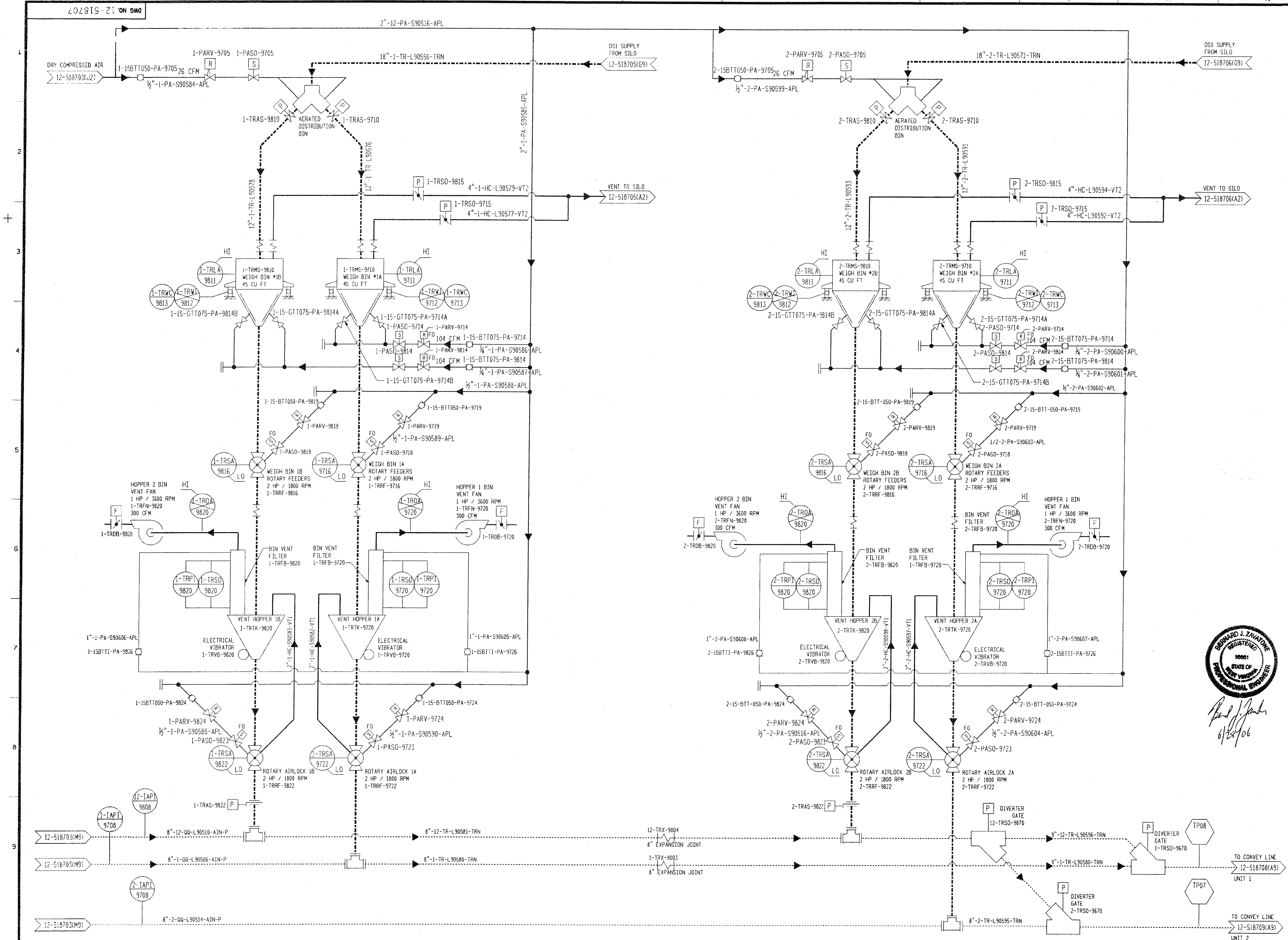
MITCHELL PLANT

CRESAP WEST VIRGINIA

DSI SYSTEM SILO 2 & RECLAIM FLOW DIAGRAM

DWG. NO. 12-518706-0

AEP AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW

NOTES

(I) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D
5004E
5004

REFERENCE PROJECT PROCEDURE

PE-FL-EN-0001

DATE	NO.	DESCRIPTION	APPD.
06/21/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

g:/mt/1/flow_diagram/517802.dgn

AMERICAN ELECTRIC POWER

MITCHELL PLANT

CRESAP WEST VIRGINIA

DSI SYSTEM LIW FEEDERS & TRANSPORT LINE FLOW DIAGRAM

DWG. NO. 12-518707-0

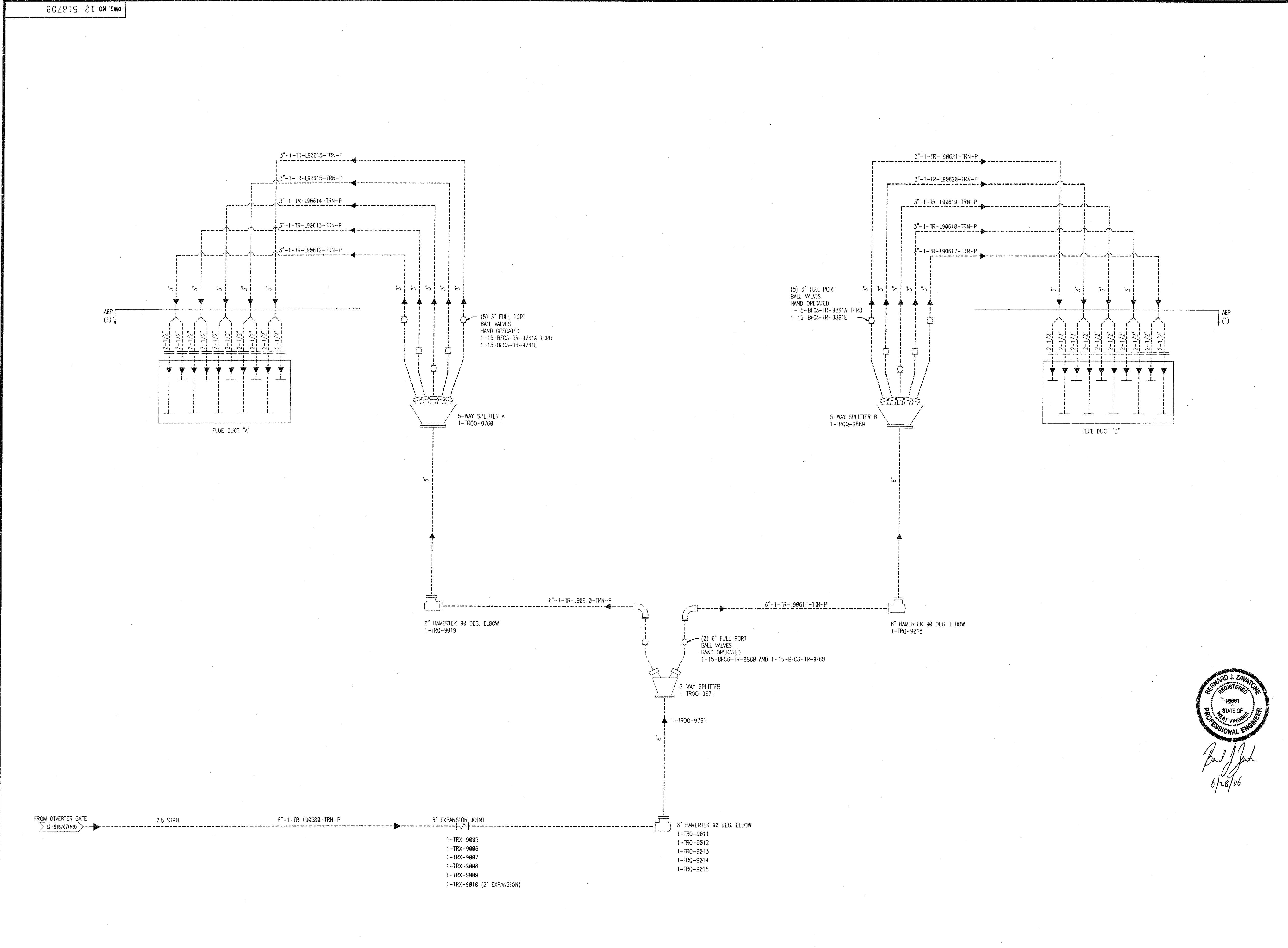
SCALE: NONE
DR: RDS
CHK:
APPROVED BY
DATE:

AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

BERNARD J. ZAVATONE REGISTERED 16601 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

SYSTEM DATE=5/21/2006
SYSTEM TIME=4:8:07 PM



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW

NOTES

(1) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D
5004E
5004

REFERENCE PROJECT PROCEDURE

PE-FL-EN-0001

DATE	NO.	DESCRIPTION	APPD.
05/25/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

s:/mt/1/flow_diagram/518708.dgn

AMERICAN ELECTRIC POWER

MITCHELL PLANT

CRESAP WEST VIRGINIA

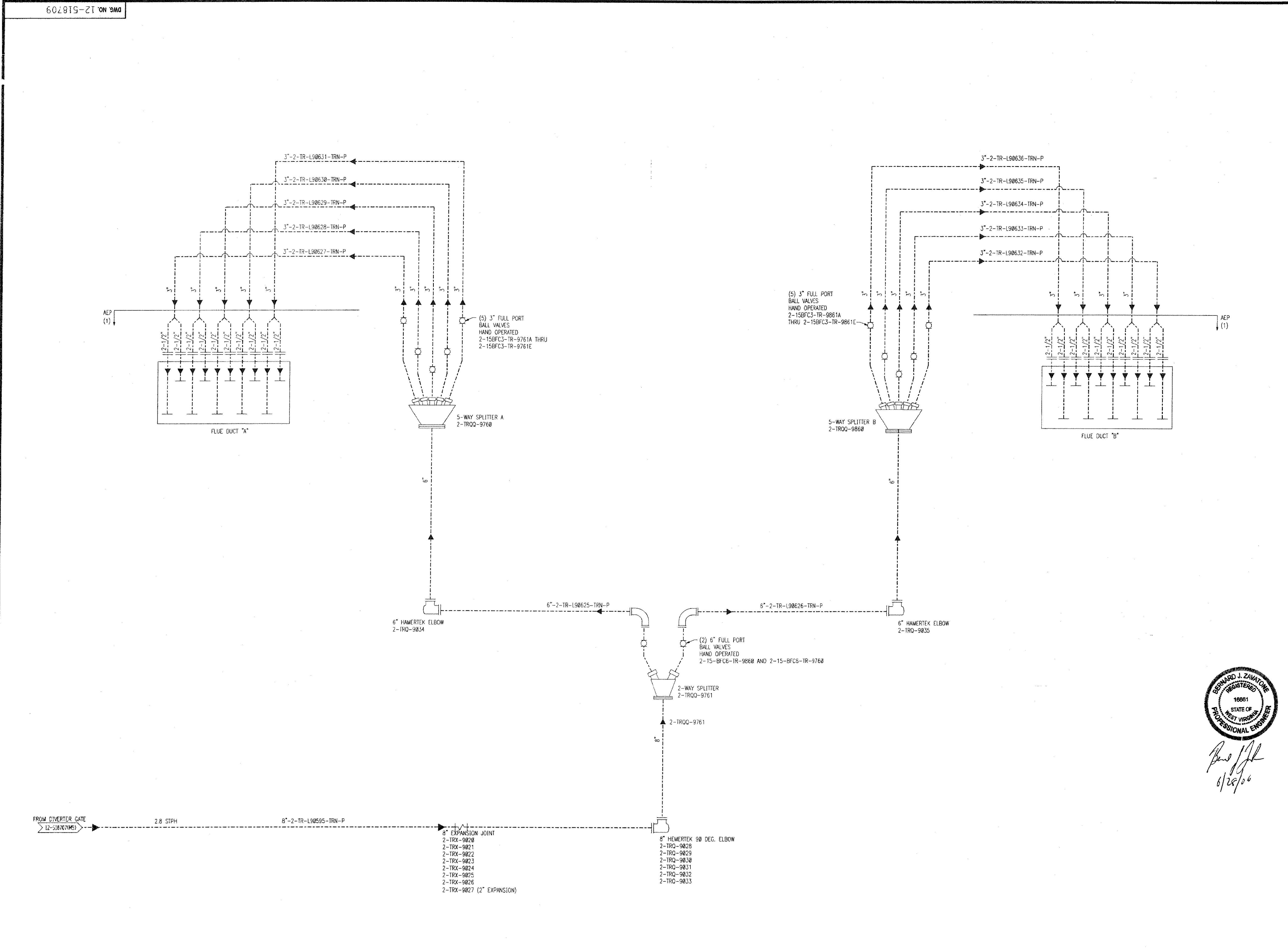
DSI SYSTEM UNIT 1 DUCT INJECTION FLOW DIAGRAM

DWG. NO. 12-518708-0

SCALE: NONE
DR: RDS
CH:
APPROVED BY
DATE:

AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

SYSTEM DATE-6/21/2006
SYSTEM TIME-4:07:10 PM



LEGEND

- DSI SUPPLY
- DSI CHUTE WORK
- VENT PIPING
- COMPRESSED AIR
- GLYCOL SYSTEM
- AIR BLOWER LINES
- HYDRAULIC FLUID
- HAMMERTEK ELBOW
- LONG RADIUS ELBOW

NOTES

(1) DENOTES PIPE & VALVES BY AEP

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003029 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D 5004E 5004

REFERENCE PROJECT PROCEDURE

PE-FL-EN-0001

DATE	NO.	DESCRIPTION	APPD.
05/25/06	0	ISSUED FOR CONSTRUCTION.	

REVISIONS

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

FLSMIDTH 2040 AVENUE C BETHLEHEM, PA 18017

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AMERICAN ELECTRIC POWER

MITCHELL PLANT

CRESAP WEST VIRGINIA

DSI SYSTEM UNIT 2 DUCT INSERTION FLOW DIAGRAM

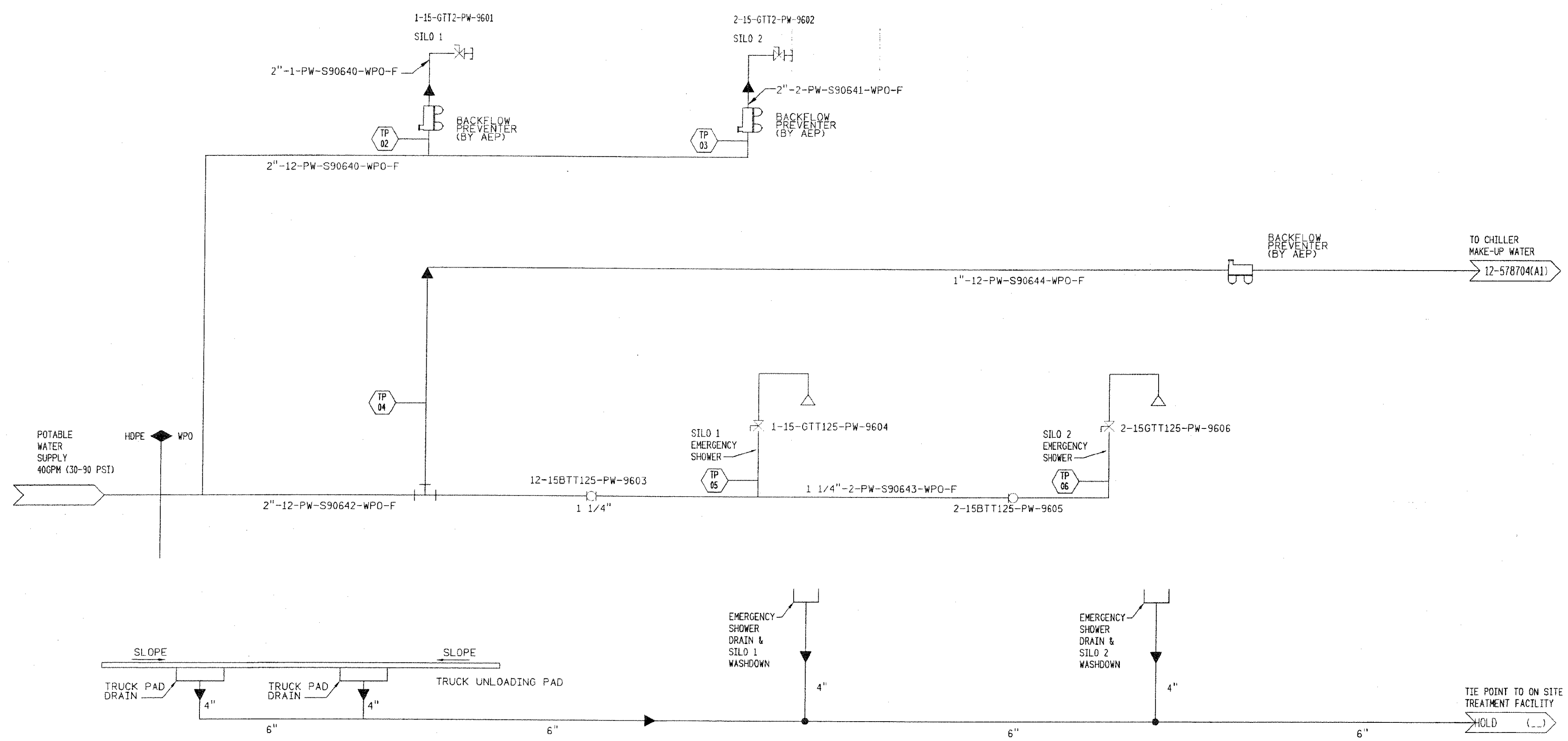
DWG. NO. 12-518709-0

SCALE: NONE
DR: RSB
CHK
DATE:
APPROVED BY

AMERICAN ELECTRIC POWER — AEP SERVICE CORP. 1 RIVERSIDE PLAZA COLUMBUS, OH 43215

SYSTEM DATE-6/21/2006
SYSTEM TIME-4:07:13 PM

DWG. NO.12-518710



(1) DENOTES PIPE & VALVES BY AEP

NOTES

FOR GENERAL NOTES SEE DRAWING 1-518701

1. ALL EQUIPMENT BY F.L. SMIDTH, UNLESS NOTED.
2. REFER TO F.L.S. DOCUMENT NO. 7003023 FOR PIPE MATERIAL SPECIFICATIONS.
3. ALL TAG NAMES ARE PRECEDED BY ML- UNLESS NOTED.

REFERENCE DRAWINGS

STANDARD SYMBOLS -------- 5004D
5004E
5004

REFERENCE PROJECT PROCEDURE

DATE	NO.	DESCRIPTION	APPD.
05/25/06	0	ISSUED FOR CONSTRUCTION	

REVISIONS

BERNARD J. ZAVATONE REGISTERED 16661 STATE OF WEST VIRGINIA PROFESSIONAL ENGINEER

6/28/06

APPALACHIAN POWER COMPANY

MITCHELL PLANT

CRESAP WEST VIRGINIA

DSI SYSTEM SERVICE WATER & POTABLE WATER FLOW DIAGRAM

DWG. NO.12-518710-0

SCALE: NONE — MECHANICAL ENGINEERING DIVISION

DR: JF
CH:
DES SUPV:
PROJ ENGR:
DATE: 03/01/06
APPROVED BY

RIVER CONSULTING New Orleans - Columbus - Pittsburgh Salt Lake City - Houston

FLSMIDTH

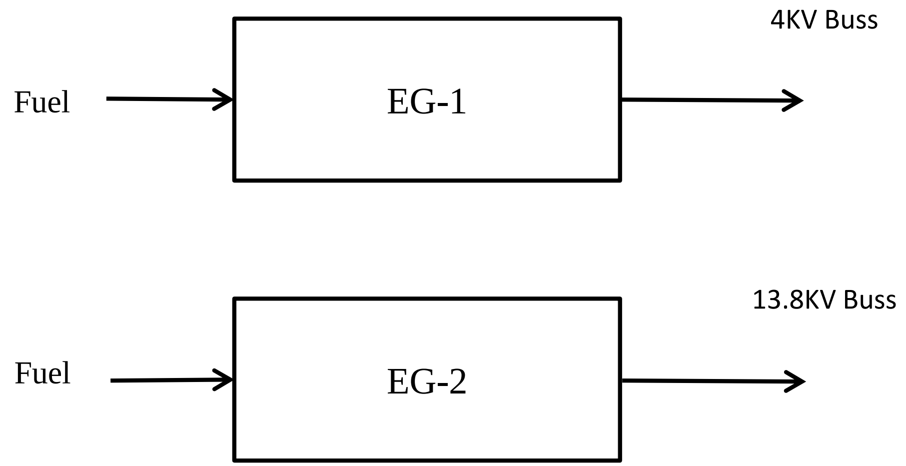
AMERICAN ELECTRIC POWER

AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

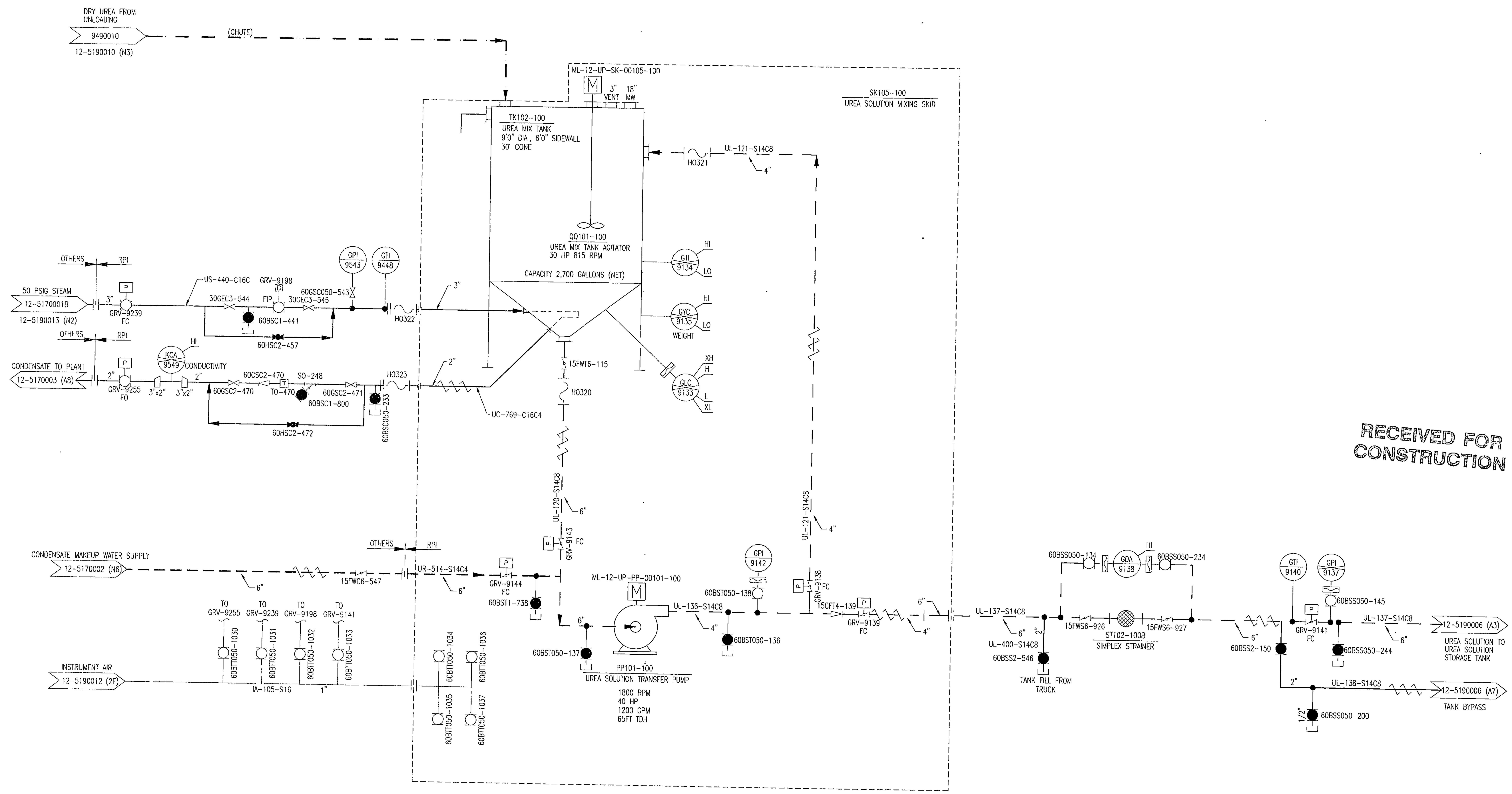
0 Rev. No: Plot Date: Plotted by:

Flow Diagram

Coping Power Diesel Driven Emergency Generators



DWG. NO. 100273-9490020



RECEIVED FOR CONSTRUCTION

NOTES:

1. DELETED
2. ALL TAG #'S PREFACED WITH ML12 UNLESS OTHERWISE SPECIFIED

LEGEND

- DRY UREA
- UREA SOLUTION
- MAKE-UP WATER
- AUX PIPING

DATE	NO	DESCRIPTION	APP'D
	2	CORRECT ARROW REFS, DELETED LINE TO SUMP, ADDED DRAIN VALVE, RELOCATED DRAIN VALVE, ADDED TRAP STRAINER TAG & DRAIN LINE TAG	
	1	RE-ISSUE FOR CONSTRUCTION	
	0	ISSUE FOR CONSTRUCTION	

REVISIONS

ALTERATION	NO	BY	CHK	DATE	APP'D	DATE
CORRECT ARROW REFS, DELETED LINE TO SUMP, ADDED DRAIN VALVE, RELOCATED DRAIN VALVE, ADDED TRAP STRAINER TAG & DRAIN LINE TAG	05	LKT		5/5/06		5/11/06
RE-ISSUE FOR CONSTRUCTION	04	JWL	RB	11/17/05	CAE	11/18/05
ISSUE FOR CONSTRUCTION	03	JWL	BH	05/20/05	CAE	05/20/05
RELEASED FOR APPROVAL	02	JWL	TN	04/30/05	CAE	05/01/05
RELEASED FOR CERTIFICATION	01	JWL	TN	04/12/05	BH	04/12/05

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THIS DRAWING IS NOT APPROVED FOR CONSTRUCTION UNLESS IT CONTAINS DATE AND SIGNATURE OF APPROVAL AND THE COMPANY RESERVES THE RIGHT TO CORRECT ANY ERRORS OR OMISSIONS PRIOR TO ACTUAL START OF WORK

RILEY POWER INC.
CLAYTON ERICKSON 05/20/05
RELEASED & APPROVED

DRAWN JWL DATE 04/28/05
CHECKED RH DATE 03/17/05
APP'D RJ DATE 03/17/05

FUNCTIONAL REVIEW / APPROVAL
RB 11/17/05
RHF 11/18/05
C.ERICKSON 11/18/05
B.BASILE 11/18/05

DO NOT SCALE USE DIMENSIONS ONLY
SCALE NTS

03389 - 12-5190011---2
AEPM-12-DV-094502-12-5190011-R2(6)

RILEY POWER INC.

PIPING AND INSTRUMENTATION DIAGRAM
UREA MIX TANK
U2A SYSTEM
MITCHELL PLANT - UNITS #1 & 2
AMERICAN ELECTRIC POWER
CRESAP, WEST VIRGINIA

DWG. NO. 100273-9490020-05

OHIO POWER COMPANY
MITCHELL PLANT
CRESAP WEST VIRGINIA

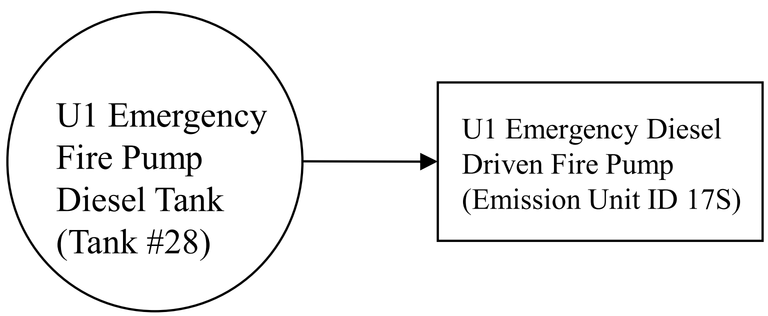
FLOW DIAGRAM
UREA MIX TANK
U2A SYSTEM

DWG. NO. 12-5190011 -2

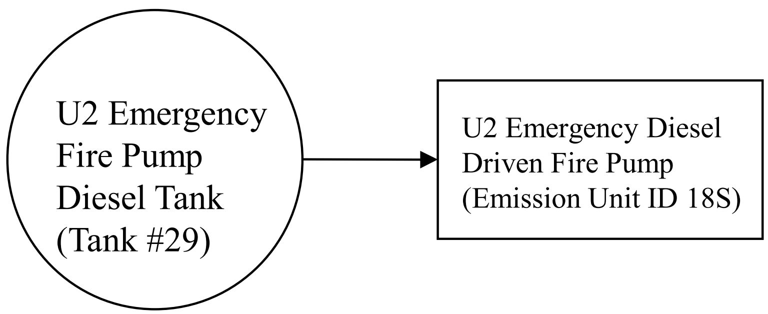
DOCUMENT PREPARED BY RILEY POWER INC.

AEP SERVICE CORP.
1 RIVERSIDE PLAZA

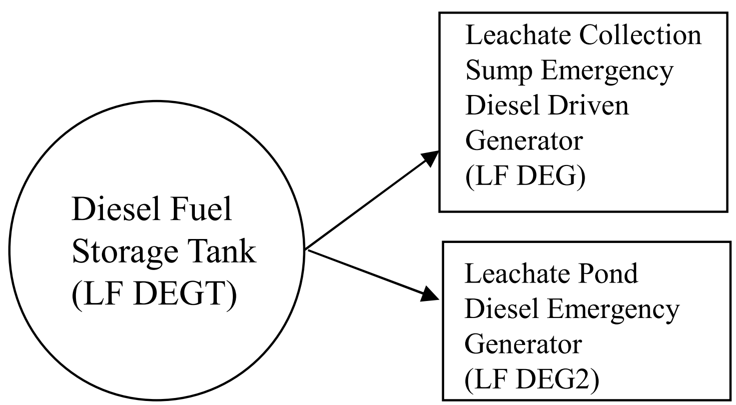
Attachment C:
Mitchell Plant Unit 1 Emergency Diesel Driven Fire Pump



Attachment C:
Mitchell Plant Unit 2 Emergency Diesel Driven Fire Pump



Attachment C:
Mitchell Plant Diesel Driven Emergency Generators Located at Landfill Leachate Collection Sump and Leachate Pond



Attachment D

Title V Equipment Table

ATTACHMENT D - Title V Equipment Table

(includes all emission units at the facility except those designated as insignificant activities in Section 4, Item 24 of the General Forms)

Emission Point ID[1]	Control Device[1]	Emission Unit ID[1]	Emission Unit Description	Design Capacity	Year Installed/ Modified
Boiler & Associated Equipment					
Unit 1	High efficiency	1E	Boiler: Foster Wheeler, Model # 2-85-303	7020 mmBtu/hr	1971
Unit 2	High efficiency	2E	Boiler: Foster Wheeler, Model # 2-85-304	7020 mmBtu/hr	1971
Aux 1	N/A	Aux ML1	Boiler: Foster Wheeler, Model # SD- 25	663 mmBtu/hr	1970, Reconstructed in 2012
17E	None	17S	Unit 1 Emergency Diesel Driven Fire Pump	249 HP	~1971, Replaced in 2023
18E	None	18S	Unit 2 Emergency Diesel Driven Fire Pump	249 HP	~1971, Replaced in 2024
EG-1	None	EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	3,717-bhp@ 1,800rpm	2014
EG-2	None	EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	3,004-bhp@ 1,800rpm	2014
LF DEG	None	LF DEG	Landfill Leachate Collection Sump Emergency Diesel Driven Generator, 2019 Cummins C300DQDAC model	464 bhp 300kW	2020
LF DEG2	None	LF DEG2	Landfill Leachate Pond Diesel Emergency Generator, 2023 Cummins QSG12 model	513 bhp 400kW	2023
LF DEGT	None	LF DEGT	Diesel Fuel Storage Tank for LF DEG	600 gallons	2020
LF DEGT2	None	LF DEGT2	Diesel Fuel Storage Tank for LF DEG2	600 gallons	2023
EGT01	None	EGT01	Diesel Fuel Storage Tank for EG-1	4,800 gallons	2014
EGT02	None	EGT02	Diesel Fuel Storage Tank for EG-2	4,800 gallons	2014
Coal Handling					
BU	WS, PE, MC	BU	Barge Unloader (unload barge onto Conveyor R1	4,000 TPH	1971
Station R1	FE, MC	Sta-R1	Conveyor R1 and drop points to Conveyor R2	3,000 TPH	1971
C-R2	WS, PE, MC	C-R2	Conveyor R2 (transfer to Station R2)	3,000 TPH	1971
RCU	WS, MC	RCU	Rail Car Unloader (unload rail cars to feeders R6-1, R6-2 and R6-3)	3,000 TPH	April, 1974
R6-1, R6-2, R6-3	PE, MC	R6-1, R6-2, R6-3	Feeders R6-1, R6-2, R6-3 (transfer points to Conveyor R7)	1,400 TPH	April 1974
C-R7	WS, PE, MC	C-R7	Conveyor R7 (transfer to Station R2)	3,000 TPH	April 1974
Station R2	FE, MC	Sta-R2	Drop point to coal crusher or conveyor R3	N/A	April 1974
CR-R2	FE, MC	CR-R2	Coal Crusher	2,500 TPH	1971

C-R3	PE, MC	C-R3	Conveyor R3 (transfer to Station R3)	3,000 TPH	1971
Station R3	FE, MC	Sta-R3	Drop point to conveyor R4 or R1 1	N/A	1971
C-R1 1	PE, MC	C-R1 1	Conveyor R1 1 (transfer to radial portable Conveyor R12)	3,000 TPH	1971
C-R12	MC	C-R12	Radial Portable Conveyor R12 (transfer to temporary storage pile)	3,000 TPH	1971
C-R4	PE, MC	C-R4	Conveyor R4 (transfer to Station R4)	3,000 TPH	1971
Station R4	FE, MC	Sta-R4	Drop point to Sample System and Conveyor R5; and/or Conveyor R8	N/A	1971
C-R8	PE, MC	C-R8	Conveyor R8 (transfer to Radial Stacker Conveyor R9)	3,000 TPH	April 1974
C-R9	MC	C-R9	Radial Stacker Conveyor R9 (transfer to North Yard Storage Pile – Station R7)	3,000 TPH	April 1974
Station R7	FE, MC	Sta-R7	Drop point from North Yard Storage Pile through Crusher R7-1 to Feeder Conveyor BFR7-1	N/A	April 1974
CR-R7-1	FE, MC	CR-R7-1	Coal Crusher	1,000 TPH	April 1974
BFR7-1	FE, MC	BFR7-1	Feeder BFR7-1 (transfer to Conveyor R10)	1,100 TPH	April 1974
C-R1 0	PE, MC	C-R10	Conveyor R10 (transfer to truck load out and Station R4)	1,100 TPH	April 1974
C-R5	PE, MC	C-R5	Conveyor R5 (transfer to Drive Tower S1)	3,000 TPH	1971
Drive Tower S1	FE, MC	Drive Tower S1	Drop point to Conveyor R6	N/A	1971
C-R6	PE, MC	C-R6	Conveyor R6 (transfer to Station 2)	3,000 TPH	1971
Station 2	FE, MC	Sta-2	Drop point to Radial Stacker Conveyor 2	N/A	1969
RS-2	WS, MC	RS-2	Radial Stacker 2 (transfer to surge pile)	4,000 TPH	1969
Station 1A	FE, MC	Sta-1A	Drop point from frozen coal storage area 4 through crusher CR-1A to Conveyor 1A	N/A	1969
CR-1A	FE, MC	CR-1A	Coal Crusher	1,000 TPH	1969
C-1A	PE, MC	C-1A	Conveyor 1A (transfer to Station 1B)	1,100 TPH	1969
Station 1B	FE, MC	Sta-1B	Drop point to Conveyor 1	N/A	1969
C-1	PE, MC	C-1	Conveyor 1 (transfer to Station 2)	2,600 TPH	1969
CSA-1	MC	CSA-1	Coal Storage Area #1 (Surge Pile)	Approx 40 Acres	1969
CSA-2	MC	CSA-2	Coal Storage Area #2 (North Yard Storage Pile)	Approx 40 Acres	April 1974
CSA-3	MC	CSA-3	Coal Storage Area #3 (Temporary Storage Pile at R3)	Approx 6 Acres	
CSA-4	MC	CSA-4	Coal Storage Area #4 (conveyor from 1B)	Included in CSA-1	1969
SGM1 through SGM16	FE, MC	SGM1 through	Reclaim Hoppers/Vibratory Feeders (Reclaim Area #1 surge pile) transfers to Conveyors 3A, 3B and 3C	300 TPH each	1969
C-3A	FE, MC	C-3A	Conveyor 3A (transfer to Station 3B)	1,100 TPH	1969
Station 3B	FE, MC	Sta-3B	Drop point to Conveyor 3B	N/A	1969
C-3B	FE, MC	C-3B	Conveyor 3B (transfer to Station 3)	1,100 TPH	1969
C-3C	FE, MC	C-3C	Conveyor 3C (transfer to Station 3)	1,100 TPH	1969
Station 3	FE, MC	Sta-3	Drop point to Conveyors 4E and/or 4W	N/A	1969

C-4E/C-4W	PE, MC	C-4E/C-4W	Conveyors 4E and 4W (transfer to Station 4)	1,100 TPH each	1969
Station 4	FE, MC	Sta-4	Drop point to Sample System, Conveyor 7E and/or 7W, and Conveyor 5 or Emergency Conveyors E25 through E2 1	N/A	1969
C-7E/C-7W	PE, MC	C-7E/C-7W	Conveyors 7E and 7W (transfer to Station 5	1,100 TPH each	1969
C-5	FE, MC	C5	Conveyor 5 (transfer to Unit 2 coal silos 3, 4 or 5 and to Conveyor 6)	1,100 TPH	1969
C-6	FE, MC	C-6	Conveyor 6 (transfer to Unit 2 coal silos 1 or 2)	1,100 TPH	1969
C-E25 through C- E21	MC	C-E25 through C-E21	Emergency conveyors E25 through E21 (used in an emergency to transfer coal into Unit 2 coal silos)	500 TPH each	1969
Station 5	FE, MC	Sta-5	Drop point to Conveyor 8 or Emergency Conveyors E1 1 through E15	N/A	1969
C-8	FE, MC	C-8	Conveyor 8 (transfer to Unit 1 coal silos 3, 4, or 5 and to Conveyor 9)	1,100 TPH	1969
C-9	FE, MC	C-9	Conveyor 9 (transfer to Unit 1 coal silos 1 or 2)	1,100 TPH	1969
C-E1 1 through C- E15	MC	C-E1 1 through C-E15	Emergency conveyors E1 1 through E15 (used in an emergency to transfer coal into Unit 1 coal silos)	500 TPH	1969
Fly Ash Material Handling					
Haul Roads	Water Truck	Haul Roads	Fly Ash Material Haul Roads and Landfill	N/A	N/A
EP-1	Filter/Separator	ME-1A	Unit 1 Mechanical Exhauster 1A	N/A	2012
EP-2	Filter/Separator	ME-1B	Unit 1 Mechanical Exhauster 1B	N/A	2012
EP-3	Filter/Separator	ME-1C (spare)	Unit 1 Mechanical Exhauster 1C	N/A	2012
EP-4	Filter/Separator	ME-2A	Unit 2 Mechanical Exhauster 2A	N/A	2012
EP-5	Filter/Separator	ME-2B	Unit 2 Mechanical Exhauster 2B	N/A	2012
EP-6	Filter/Separator	ME-2C (spare)	Unit 2 Mechanical Exhauster 2C	N/A	2012
EP-7	BVF-A	FAS-A	Fly Ash Silo A	2,160 tons	2012
EP-8	BVF-B	FAS-B	Fly Ash Silo B	2,160 tons	2012
EP-9	BVF-C	FAS-C	Fly Ash Silo C	2,160 tons	Future
F-1	MC	WFA-AA	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	360 tph	2012
F-2	MC	WFA-BA	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	360 tph	2012
F-3	MC	WFA-CA	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	360 tph	Future
F-4	MC	WFA-AB (spare)	Transfer conditioned fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	360 tph	2012
F-5	MC	WFA-BB (spare)	Transfer conditioned fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	360 tph	2012
F-6	MC	WFA-CB (spare)	Transfer conditioned fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	360 tph	Future
EP-10, F-7	TC	TC-A	Transfer dry fly ash from Fly Ash Silo A to Truck via Pin/Paddle Mixer	300 tph	2012
EP-11, F-8	TC	TC-B	Transfer dry fly ash from Fly Ash Silo B to Truck via Pin/Paddle Mixer	300 tph	2012
EP-12, F-9	TC	TC-C	Transfer dry fly ash from Fly Ash Silo C to Truck via Pin/Paddle Mixer	300 tph	Future

~~LPG~~	~~None~~	~~LPG~~	~~Generac SG080, Lean Burn Four Stroke, Liquid Propane Gas-fired emergency generator Certificate No. DGNXB08.92NL-011~~	~~126 bhp~~	~~2013~~ **(Removed)**
~~LPT~~	~~None~~	~~LPT~~	~~Liquid Propane Tank for LPG~~	~~500 gallons~~	~~2013~~ **(Removed)**
1S – Limestone Material Handling					
BUN-1 (Fugitive)	None	BUN-1	Limestone Unloading Crane	1,000 TPH	2006
RH-1 (Fugitive)	WS, PE	RH-1	Limestone Unloading Hopper	60 Tons	2006
VF-1 (Fugitive)	FE	VF-1	Limestone Unloading Feeder	750 TPH	2006
BC-1 (Fugitive)	PE	BC-1	Limestone Dock/Connecting Conveyor	750 TPH	2006
TH-1 (Fugitive)	FE	TH-1	Limestone Transfer House #1	750 TPH	2006
BC-2 (Fugitive)	PE	BC-2	Limestone Storage Pile Stacking Conveyor	750 TPH	2006
LSSP (Fugitive)	None	LSSP	Limestone Active/Long-Term Stockpile	155,000 Tons	2006/2011
2S - Gypsum Material Handling					
BC-8 (Fugitive)	PE	BC-8	Vacuum Collecting Conveyor	200 TPH	2007
TH-3 (Fugitive)	FE	TH-3	Gypsum Transfer House #3	200 TPH	2007
BC-9 (Fugitive)	PE	BC-9	Connecting Conveyor	200 TPH	2007
TH-4 (Fugitive)	FE	TH-4	Gypsum Transfer House #4	200 TPH	2007
BC-10 (Fugitive)	PE	BC-10	Connecting Conveyor	200 TPH	2007
TH-5 (Fugitive)	FE	TH-5	Gypsum Transfer House #5	200 TPH	2007
BC-11 (Fugitive)	PE	BC-11	Connecting Conveyor	200 TPH	2007
TH-6 (Fugitive)	FE	TH-6	Gypsum Transfer House #6	200 TPH	2007
BC-12 (Fugitive)	PE	BC-12	Stacking Tripper Conveyor	200 TPH	2007
GSP (Fugitive)	FE	GSP	Gypsum Stockpile	15,600 tons	2007
PSR-1 (Fugitive)	FE	PSR-1	Traveling Portal Scraper Reclaimer	1,000 TPH	2007
BC-14 Fugitive)	PE	BC-14	Reclaim Conveyor	1,000 TPH	2007
TH-7 (Fugitive)	FE	TH-7	Transfer House #7	1,000 TPH	2007
BC-13 (Fugitive)	PE	BC-13	Bypass Conveyor	200 TPH	2007
BC-15 (Fugitive)	PE	BC-15	Connecting Conveyor	1,000 TPH	2007
TH-1 (Fugitive)	FE	TH-1	Transfer House #1	1,000 TPH	2007
BC-16 (Fugitive)	PE	BC-16	Transfer Conveyor	1,000 TPH	2007
BL-1 (Fugitive)	PE	BL-1	Barge Loader	1,000 TPH	2007
BC-14 (Fugitive)	PE	BC-14	Reclaim Conveyor Extension	1,000 TPH	2007

TH-8 (Fugitive)	FE	TH-8	Transfer House 8	1,000 TPH	2007
BC-19 (Fugitive)	PE	BC-19	Transfer Conveyor	1,000 TPH	2007
TH-9 (Fugitive)	FE	TH-9	Transfer House 9	1,000 TPH	2007
BC-20 (Fugitive)	PE	BC-20	Transfer Conveyor to 20	1,000 TPH	2007
TH-10 (Fugitive)	FE	TH-10	Transfer House 10	1,000 TPH	2007
BC-21 (Fugitive)	PE	BC-21	Transfer Conveyor to 21	1,000 TPH	2007
BUN-1 (Fugitive)		BUN-1	Clamshell Unloading Crane	1,000 TPH	2007
RH-4 (Fugitive)	WS, PE	RH-4	Gypsum Unloading Hopper	30 tons	2007
RP-1 (Fugitive)	FE	RP-1	Gypsum Rotary Plow	750 TPH	2007
BC-17 (Fugitive)	PE	BC-17	Dock/Connecting Conveyor	750 TPH	2007
TH-7 (Fugitive)	FE	TH-7	Transfer House #7	750 TPH	2007
BC-18 (Fugitive)	PE	BC-18	Bypass Conveyor	750 TPH	2007
TH-6 (Fugitive)	FE	TH-6	Transfer House #6	750 TPH	2007
3S - Limestone Mineral Processing					
VF-2 (Fugitive)	FE	VF-2	Limestone Reclaim Feeder 2	750 TPH	2007
VF-3 (Fugitive)	FE	VF-3	Limestone Reclaim Feeder 3	750 TPH	2007
BC-3 (Fugitive)	PE	BC-3	Limestone Tunnel Reclaim Conveyor	750 TPH	2007
FB-1 (Fugitive)		FB-1	Emergency Limestone Reclaim Feeder/Breaker	750 TPH	2007
TH-2 (Fugitive)	FE	TH-2	Limestone Transfer House 2	750 TPH	2007
BC-4 (Fugitive)	PE	BC-4	Limestone Silo A Feed Conveyor	750 TPH	2007
BC-5 (Fugitive)	PE	BC-5	Limestone Silo B Feed Conveyor	750 TPH	2007
BC-6 (Fugitive)	PE	BC-6	Limestone Silo C Feed Conveyor	750 TPH	Future
6E	BH	LSB-1	Limestone Silo A	900 Tons	2007
7E	BH	LSB-2	Limestone Silo B	900 Tons	2007
8E	BH	LSB-3	Limestone Silo C	900 Tons	Future
(Fugitive)	FE		Vibrating Bin Discharger (one per silo)	68.4 TPH	2007
LSWF-1 (Fugitive) LSWF-2 (Fugitive) LSWF-3(Fugitive)	FE	LSWF-1 LSWF-2 LSWF-3	Limestone Weigh Feeder (one per silo)	68.4 TPH	2007
(Fugitive)	FE		Wet Ball Mill (one per silo)	68.4 TPH	2007
4S - Dry Sorbent Material Handling					

(Fugitive)	FE		Truck Unloading Connection (2)	25 TPH	2007
10E	BH, FE	DSSB 1	Dry Sorbent Storage Silo #1	500 TPH	2007
11E	BH, FE	DSSB 2	Dry Sorbent Storage Silo #2	500 TPH	2007
(Fugitive)	FE		Aeration Distribution Bins	4.6 TPH	2007
(Fugitive)	FE		De-aeration Bins	4.6 TPH	2007
(Fugitive)	FE		Rotary Feeder	4.6 TPH	2007
5S - Coal Blending System					
HTS-1 (Fugitive)	FE	HTS-1	Transfer House #1	3,000 TPH	2007
HSC-1 (Fugitive)	PE	HSC-1	Stacking Conveyor #1	3,000 TPH	2007
HTS-2A (Fugitive)	FE	HTS-2A	Transfer House #2A	3,000 TPH	2007
HSC-2 (Fugitive)	PE	HSC-2	Stacking Conveyor #2	3,000 TPH	2007
HTS-3 (Fugitive)	FE	HTS-3	Transfer House #3	3,000 TPH	2007
HSC-3 (Fugitive)	PE	HSC-3	Stacking Conveyor #3	3,000 TPH	2007
SH-1 (Fugitive)	FE	SH-1	Stacking Hopper SH-1 Transfer to SC-3 (receive coal from plant radial stacker R9)	3,000 TPH	2007
HSC-3 to High Sulfur Pile (Fugitive) (CSA-2, existing)	Stacking Tube	HSC-3 to High Sulfur Pile (CSA-2, existing)	Transfer from Stacking Conveyor HSC-3 to High Sulfur Pile at existing North Yard Storage Area (CSA-2)	3,000 TPH	2007
HVF-1 (Fugitive)	FE	HVF-1	Coal Reclaim Feeder 1	800 TPH	2007
HVF-2 (Fugitive)	FE	HVF-2	Coal Reclaim Feeder 2	800 TPH	2007
HVF-3 (Fugitive)	FE	HVF-3	Coal Reclaim Feeder 3	800 TPH	2007
HVF-4 (Fugitive)	FE	HVF-4	Coal Reclaim Feeder 4	800 TPH	2007
HVF-1 through HVF-4 to HRC-1 (Fugitive) (Transfer)	FE	HVF-1 through HVF-4 to HRC-1 (Transfer)	Transfer from Vibrating Feeders HVF-1 through HVF-4 to Reclaim Conveyor HRC-1	1,600 TPH	2007
HRC-1 (Fugitive)	PE	HRC-1	Coal Tunnel Reclaim Conveyor	1,600 TPH	2007
HTS-2B (Fugitive)	FE	HTS-2B	Coal Transfer House #2B	1,600 TPH	2007
HRC-2 (Fugitive)	PE	HRC-2	Reclaim Conveyor #2	1,600 TPH	2007
HTS-4 (Fugitive)	FE	HTS-4	Coal Transfer House #4	1,600 TPH	2007
HRC-3 (Fugitive)	PE	HRC-3	Reclaim Conveyor #3	1,600 TPH	2007
HTS-5 (Fugitive)	FE	HTS-5	Coal Transfer House #5	1,600 TPH	2007
SB-1 (Fugitive)	FE	SB-1	Surge Bin #1	80 Tons	2007
HBF-1A (Fugitive)	PE	HBF-1A	Belt Feeder 1A	800 TPH	2007
HBF-1B (Fugitive)	PE	HBF-1B	Belt Feeder 1B	800 TPH	2007
HBF-1A/1B to BF-4E/4W (Fugitive)	FE	HBF-1A/1B to BF-4E/4W	Transfer from Belt Feeders HBF-1A and HBF-1B to Existing Coal Conveyors 4E and 4W	1,600 TPH	2007

6S, 7S - Emergency Quench Water System					
15E	FE	6S	Diesel Engine on Quench Pump #1	60 HP (approx.)	2007
16E	FE	7S	Diesel Engine on Quench Pump #2	60 HP (approx.)	2007
9S – Magnesium Hydroxide Material Handling System					
MHM-1	N/A	MHM-1	Magnesium Hydroxide Mix Tank #1	1000 Gal.	2007
MHM-2	N/A	MHM-2	Magnesium Hydroxide Mix Tank #2	1000 Gal.	2007
11S – Wastewater Treatment Material Handling					
Fugitive	FE		Truck Unloading Connection (2)	25 TPH	2007
24E	BH, FE		Lime Storage Silo #1	100 TPH	2007
25E	BH, FE		Lime Storage Silo #2	100 TPH	2007
Fugitive	Building Enclosure		Wastewater Treatment Cake Stockpile	3,600 Tons	2007
Fugitive	PE	FB-2	Filter Cake Feeder/Breaker	600 TPH	2007
Fugitive	PE	BC-22	Transfer Conveyor 22	600 TPH	2007
Fugitive	PE	TH-12	Transfer House #12	600 TPH	2007
Miscellaneous Other					
Tank #1	N/A	Tank #1	Ignition Oil Tank – S. of U1 Cooling Tower	1,500,000 Gal.	~1975
Tank #2	N/A	Tank #2	Ignition Oil Tank – N. of U2 Cooling Tower	500,000 Gal.	1971
Tank #3	N/A	Tank #3	Ignition Oil Tank – N. of U2 Cooling Tower	500,000 Gal.	1971
Tank #4	N/A	Tank #4	Used Oil Tank – S. of U1 Cooling Tower	1,000 Gal.	Relocated ~2004
Tank #5	N/A	Tank #5	Used Oil Tank – Tractor Shed	500 Gal.	~2000
Tank #6	N/A	Tank #6	Sulfuric Acid Tank – W. of Units 1&2	15,000 Gal.	1971
Tank #7	N/A	Tank #7	Ammonium Hydroxide Tank – W. of Units 1 &2	4,750 Gal.	1971
Tank #8	N/A	Tank #8	Diethylene Glycol Tank – N. of Station R-4	500 Gal.	~2002
Tank #9	N/A	Tank #9	Diethylene Glycol Tank – Station 3	300 Gal.	~2002
Tank #10	N/A	Tank #10	Diethylene Glycol Tank – Station R-4	300 Gal.	~2002
Tank #11	N/A	Tank #11	No.2 Fuel Oil Tank – Coal Transfer Station #3	1,000 Gal.	2007
Tank #12	N/A	Tank #12	No.2 Fuel Oil Tank – Coal Transfer Station R-2	3,000 Gal	~2004
Tank #13	N/A	Tank #13	No.2 Fuel Oil Tank – Coal Transfer Station R-4	3,000 Gal.	~2004
Tank #14	N/A	Tank #14	No.2 Fuel Oil Tank – Drain Receiver Tank	400 Gal.	1969
Tank #15	N/A	Tank #15	Gasoline Tank – Main Plant Entrance	8,000 Gal.	1991
Tank #16	N/A	Tank #16	Diesel Fuel Tank – Tractor Shed	10,000 Gal	1991
Tank #17	N/A	Tank #17	Turbine Oil Tank – U1	~14,000 Gal.	1971

Tank #18	N/A	Tank #18	Turbine Oil Tank – U2	~14,000 Gal.	1971
Tank #19	N/A	Tank #19	Lube Oil Tank – U1	~20,000 Gal.	1971
Tank #20	N/A	Tank #20	Lube Oil Tank – U2	~18,000 Gal.	1971
Tank #21	N/A	Tank #21	Chemical Cleaning Solution Tank	1,000,000 Gal.	1989
Tank #22	N/A	Tank #22	EHC System Oil Tank – U1	200 Gal.	1971
Tank #23	N/A	Tank #23	New Lube Oil Tank – U1	1,000 Gal.	1971
Tank #24	N/A	Tank #24	Used Oil Bulk Tank – U1	275 Gal.	~2002
Tank #25	N/A	Tank #25	EHC System Oil Tank – U2	625 Gal.	1971
Tank #26	N/A	Tank #26	New Lube Oil Tank – U2	1,000 Gal.	1971
Tank #27	N/A	Tank #27	Used Oil Bulk Tank – U2	275 Gal.	~2002
Tank #28	N/A	Tank #28	Diesel Fire Pump Fuel Tank – U1	300 Gal.	1971, Replaced in 2023
Tank #29	N/A	Tank #29	Diesel Fire Pump Fuel Tank – U2	300 Gal.	1971, Replaced in 2024
Tank #30	N/A	Tank #30	3 Compartment Oil Tank – Tractor Shed Oil Room	920 Gal.	~1995
Tank #31	N/A	Tank #31	Single Compartment Oil Tank – Tractor Shed	560 Gal.	~1995
Tank #32	N/A	Tank #32	Waste Oil Tank – Tractor Shed Oil Room	500 Gal.	~2000
Tank #33	FE	Tank #33	Urea Receiving Hopper	45 Tons	2007
Tank #34	N/A	Tank #34	No.2 Fuel Oil Tank – Drain Receiver Tank – overflow tank	1,000 Gal.	2001
Tank #35	N/A	Tank #35	TK103-100 Urea Solution Storage Tank	200,000 Gal.	2007
Tank #36	N/A	Tank #36	TK102-100 Urea Mix Tank	2,700 Gal.	2007
Tank #37	N/A	Tank #37	CPS Lime Slurry Tank #1	750 Gal.	2007
Tank #38	N/A	Tank #38	CPS Lime Slurry Tank #2	750 Gal.	2007
Tank #39	N/A	Tank #39	CPS Equalization Tank #1	254,513 Gal.	2007
Tank #40	N/A	Tank #40	CPS Equalization Tank #2	254,513 Gal.	2007
Tank #41	N/A	Tank #41	CPS Ferric Chloride Mix Tank #1	9,200 Gal.	2007
Tank #42	N/A	Tank #42	CPS Ferric Chloride Mix Tank #2	9,200 Gal.	2007
Tank #43	N/A	Tank #43	CPS Ferric Chloride Bulk Storage Tank	8,800 Gal.	2007
~~Tank #44~~	~~N/A~~	~~Tank #44~~	~~CPS Acid Bulk Storage Tank~~	~~10,575 Gal.~~	~~2007~~ **(Removed)**
Tank #45	N/A	Tank #45	CPS Polymer Totes (2)	225 Gal. (each)	2007
Tank #46	N/A	Tank #46	Emergency Quench Pump #1 Diesel Tank	70 Gal.	2007
Tank #47	N/A	Tank #47	Emergency Quench Pump #2 Diesel Tank	70 Gal.	2007
Tank #48	N/A	Tank #48	Aux. Boiler Collection Tank Return UST	500 Gal.	2006

Tank #49	N/A	Tank #49	No. 2 Fuel Tank – SW Corner of CSA-2	2000 Gal.	2008
Tank #50	N/A	Tank #50	Gypsum Storage Building Fuel Oil Tank	1000 Gal.	2009
Tank #51	N/A	Tank #51	Highway Grade Diesel Tank #1	1000 Gal.	2011
Tank #52	N/A	Tank #52	Limestone Storage Pile Diesel Tank #1	500 Gal.	2011
Fugitive	Enclosure		Rock Salt Storage Pile (roadway ice control)	600 Tons	2010 and 2014
Tank #53	N/A	Tank #53	Landfill Building Furnace Fuel Oil Tank	2000 Gal.	2018
Tank #54	N/A	Tank #54	Landfill Gasoline Tank	520 Gal.	2018
Tank #55	N/A	Tank #55	Kerosene Tank	1,000 Gal.	2015
Tank #56	N/A	Tank #56	CPS Coagulant Tank	5,000 Gal.	2019
Tank #57	N/A	Tank #57	Unit 1 Scale Inhibitor Tank	3,500 Gal.	2015
Tank #58	N/A	Tank #58	Unit 2 Scale Inhibitor Tank	3,500 Gal.	2015
Tank #59	N/A	Tank #59	Unit 1 Dispersant Tank	5,000 Gal.	2015
Tank #60	N/A	Tank #60	Unit 2 Dispersant Tank	5,000 Gal.	2015
Tank #61	N/A	Tank #61	Unit 1 Ferric Chloride Tank	1,500 Gal.	2015
Tank #62	N/A	Tank #62	Unit 1 Ferric Chloride Tank	2,500 Gal.	2015
Tank #63	N/A	Tank #63	FGD corrosion inhibitor tank	5,000 Gal.	2015
	N/A		Landfill Building Fuel Oil Fired Furnace Clean Burn Model CB-3250	0.325 MMBtu/hr	2018
Tank #64	N/A	Tank #64	Bioreactor Nutrient Tank	12,575 Gal.	2024
Tank #65	N/A	Tank #65	Bioreactor Hydrochloric Acid Tank	6,000 Gal.	2024
Tank #66	N/A	Tank #66	WW Pond Sulfuric Acid Tank	14,500 Gal.	2023
Tank #67	N/A	Tank #67	WW Pond Sodium Hydroxide Tank	20,300 Gal.	2023
Tank #68	N/A	Tank #68	WW Pond Organosulfide Tank	6,400 Gal.	2023
Tank #69	N/A	Tank #69	WW Pond Polymer Tank	1,360 Gal.	2023

[1]For 45CSR13 permitted sources, the numbering system used for the emission points, control devices, and emission units should be consistent with the numbering system used in the 45CSR13 permit. For grandfathered sources, the numbering system should be consistent with registrations or emissions inventory previously submitted to DAQ. For emission points, control devices, and emissions units which have not been previously labeled, use the following 45CSR13 numbering system: 1S, 2S, 3S,... or other appropriate description for emission units; 1C, 2C, 3C,... or other appropriate designation for control devices; 1E, 2E, 3E, ... or other appropriate designation for emission points.

Attachment E

Emission Unit Forms

ATTACHMENT E - Emission Unit Form

Emission Unit Description Unit 1 Main Boiler

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:** ESP, SCR, FGD
Unit 1 – ML1	Unit 1 Boiler	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
Unit 1 is coal-fired EGU boiler that also utilizes oil for supplemental firing. Oil use includes, but is not limited to, periods of start-up, shutdown, stabilization and emergency operations. The boiler may also periodically combust non-hazardous material such as demineralizer resins, chemical cleaning solution, on-spec used oil, etc. The nominal design of the Unit 1 boiler is 7,020 mmBtu/hr. Coal is delivered to the site via river barge, rail car, truck or conveyor. Oil is delivered to the site via river barge or truck.

Manufacturer:	**Model number:**	**Serial number:**
Foster Wheeler	2-85-303	Custom
Construction date: MM/DD/YYYY	**Installation date:** 05/31/1971	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Nominal 7020 mmBtu/Hr (270 TPH with 13,000 BTU/lb Coal Supply) This heat input value is for operation at the nominal boiler rating. Boiler design enables the boiler to be operated above the nominal rated capacity.

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
Nominal 5,289,000 lb/hr Steam	Nominal 46,331,640,000 lb/yr Steam	8760 hr/yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? X__Yes ___ No

If yes, is it?

X__ Indirect Fired ___Direct Fired

Maximum design heat input and/or maximum horsepower rating:
8590 mmBtu/hr (rating used to model full load operation for FGD permit determination)

Type and Btu/hr rating of burners:
LNB – Foster Wheeler

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Primary: Coal; Secondary: Oil; The steam generator is capable of burning coal, and will utilize fuel oil for start-up, shutdown and for flame stabilization. Other materials burned included non-hazardous water treatment resins, chemical cleaning solution, on spec used oil, etc.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Coal (Bit.)	4.5 lb/mmBtu	12.5%	13,000 BTU/lb
Oil	0.5%	N/A	19,750 BTU/lb

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	531	2324.5
Nitrogen Oxides (NO_X)	4139	18131
Lead (Pb)	0.42	1.8
Particulate Matter ($PM_{2.5}$)	105	461.2
Particulate Matter (PM_{10})	237	1037.7
Total Particulate Matter (TSP)	351	1537.4
Sulfur Dioxide (SO_2)	10243	44862.6
Volatile Organic Compounds (VOC)	64	279
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Arsenic	0.64	2.8
Beryllium	1.53	6.7
Chromium	0.23	1.0
Cobalt	0.08	0.4
Manganese	0.43	1.9
Mercury	0.24	1.1
Nickel	0.19	0.8
Selenium	5.53	24.2
Hydrogen Chloride	1408.3	6168.3
Hydrogen Fluoride	122.3	535.6
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 4.0 through 4.1 (see Attachment I) : Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 4.2 through 4.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Unit 2 Main Boiler

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:** ESP, SCR, FGD
Unit 2 – ML2	Unit 2 Boiler	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
Unit 2 is coal-fired EGU boiler that also utilizes oil for supplemental firing. Oil use includes, but is not limited to, periods of start-up, shutdown, stabilization and emergency operations. The boiler may also periodically combust non-hazardous material such as demineralizer resins, chemical cleaning solution, on-spec used oil, etc. The nominal design of the Unit 1 boiler is 7,020 mmBtu/hr. Coal is delivered to the site via river barge, rail car, truck or conveyor. Oil is delivered to the site via river barge or truck.

Manufacturer:	**Model number:**	**Serial number:**
Foster Wheeler	2-85-304	Custom
Construction date: MM/DD/YYYY	**Installation date:** 05/31/1971	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Nominal 7020 mmBtu/Hr (270 TPH with 13,000 BTU/lb Coal Supply). This heat input value is for operation at the nominal boiler rating. Boiler design enables the boiler to be operated above the nominal rated capacity.

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
Nominal 5,280,000 lb/hr Steam	Nominal 46,252,800,000 lb/yr Steam	8760 hr/yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? X__Yes ___ No

If yes, is it?

X__ Indirect Fired ___Direct Fired

Maximum design heat input and/or maximum horsepower rating:
8,481 mmBtu/hr (rating used to model full load operation for FGD permit determination)

Type and Btu/hr rating of burners:
LNB – Foster Wheeler

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Primary: Coal; Secondary: Oil; The steam generator is capable of burning coal, and will utilize fuel oil for start-up, shutdown and for flame stabilization. Other materials burned include non-hazardous water treatment resins, chemical cleaning solution, on spec used oil, etc.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Coal	4.5 lb/mmBtu	12.5%	13,000 BTU/lb
Oil	0.5%	N/A	19,750 BTU/lb

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	531	2323.5
Nitrogen Oxides (NO_X)	4139	18131
Lead (Pb)	0.42	1.8
Particulate Matter ($PM_{2.5}$)	105	461.2
Particulate Matter (PM_{10})	237	1037.7
Total Particulate Matter (TSP)	351	1537.4
Sulfur Dioxide (SO_2)	10243	44862.6
Volatile Organic Compounds (VOC)	64	279
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Arsenic	0.64	2.8
Beryllium	1.53	6.7
Chromium	0.23	1.0
Cobalt	0.08	0.4
Manganese	0.43	1.9
Mercury	0.24	1.1
Nickel	0.19	0.8
Selenium	5.53	24.2
Hydrogen Chloride	1408.3	6168.3
Hydrogen Fluoride	122.3	535.6
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 4.0 through 4.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 4.2 through 4.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Auxiliary Boiler 1

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
Aux ML1	Auxiliary Boiler 1	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
Auxiliary Boiler 1 is an oil-fired non-EGU boiler. Use of the auxiliary boiler includes, but is not limited to heating, startup and shutdown purposes.   The nominal design of Auxiliary Boiler 1 is 663 mmBtu/hr. Oil is delivered to the site via river barge or truck.

Manufacturer:	**Model number:**	**Serial number:**
Foster Wheeler	SD-25	Custom
Construction date:	**Installation date:**	**Modification date(s):**
MM/DD/YYYY	1970, Rebuild 2012	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Nominal 663 mmBtu/Hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
355,000 lb/hr steam	310,980,000 lb/yr steam	876 hr/yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? X__Yes ___ No	**If yes, is it?** X__ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: Nominal 663 mmBtu/hr	**Type and Btu/hr rating of burners:** Front Wall

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Primary: Oil

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Oil	0.3%	N/A	19,750 Btu/lb

Page _____ of _____

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	206.8	90.6
Nitrogen Oxides (NO_X)	99.5	43.56
Lead (Pb)	0.006	0.0026
Particulate Matter ($PM_{2.5}$)	1.18	0.52
Particulate Matter (PM_{10})	4.74	2.07
Total Particulate Matter (TSP)	9.47	4.15
Sulfur Dioxide (SO_2)	39.78	17.42
Volatile Organic Compounds (VOC)	0.95	0.41
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Arsenic	0.0003	0.001
Beryllium	0.0002	0.001
Chromium	0.0002	0.001
Manganese	0.0004	0.002
Mercury	0.0002	0.001
Nickel	0.0002	0.001
Selenium	0.001	0.004
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 5.0 through 5.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 5.2 through 5.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Coal and Ash Handling

Emission unit ID number: Emission Group 003	**Emission unit name:** Coal & Ash Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, mechanical controls, water sprays.

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The coal and ash handling system consists of a barge unloader, railcar unloader, chutes and conveyors, transfer stations, crushers, storage piles and silos for coal, as well as a wet ash handling system for ash. Note that a project is currently underway to convert the wet fly ash handling system to a dry fly ash handling system. See attached description of the coal and ash handling systems.

Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Coal transfer capacity (nominal) – up to 4,000 ton/hr;   Fly Ash Handling – up to 980,000 tons per year.

Maximum Hourly Throughput: Coal: Nominal 3,000 ton/hr Fly Ash: 720 ton/hr	**Maximum Annual Throughput:** Coal - Nominal 26,280,000 ton/yr Fly Ash – 980,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes X__ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	7.2	28.6
Particulate Matter (PM_{10})	36.1	135.8
Total Particulate Matter (TSP)	92.5	318.4
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Coal and Ash Handling Description:

- **Mitchell Plant Coal Handling:**

  General Description:
  Normally, coal is received at the Mitchell Plant by river barge, rail car, truck or conveyor and is placed on the coal storage piles or transported to the coal silos for immediate plant use.

  Railcar Dumping System (Station R-6):
  Coal delivered to Mitchell Plant by rail car is unloaded at the rail car dumper and then transported by a feeder/conveyor system to Station R-2

  Coal Barge Unloader (Station R-1):
  Coal delivered to Mitchell Plant by river barge is unloaded at Station R-1 (coal barge unloader) and then transported via multiple conveyors to Station R-2

  Station R-2:
  Coal from the rail unloading and barge unloading systems enters Station R-2, where it can be crushed and then transferred to conveyor that transports it to Station R-3.

  Station R-3:
  At Station R-3, coal can be placed on a conveyor that transports it to Station R-4.

  Station R-4:
  At Station R-4, coal is sampled and then can be transferred to either a conveyor that transports the coal to Station 2 or to a series of conveyors ending with a radial stacker that discharges the coal to the North Yard long-term storage pile.

  Station 2:
  At Station 2, coal is transferred to a conveyor and then to a radial stacker for distribution on the South Yard active surge pile.

  Station R-7:
  Station R-7 is located under the North Yard storage pile. At Station R-7, coal is pushed by dozer into a reclaim hopper where it is transferred via a feeder/conveyor system to Station R-4. As described previously, coal that enters Station R-4 can be diverted vial conveyors to the Radial Stacker at Station 2 and placed on the South Yard surge pile.

  Stations 3A, 3B, and 3C:
  Stations 3A, 3B and 3C are located under the South Yard surge pile. Coal is reclaimed from the surge pile through reclaim hoppers at each of these Stations and transferred via a series of feeders/conveyors to Station 3.

  Station 1A:
  Station 1A is also located under South Yard surge pile. Coal that is reclaimed from the South Yard surge through reclaim hoppers at Station 1A can be crushed before being transferred via a feeder and conveyor to Station 1B.

  Station 1B:
  At Station 1B, coal is transferred to a conveyor that transports the coal to Station 2. As described previously, coal that enters Station 2 can be transferred onto the active surge pile via the radial coal stacker and then transferred via conveyors from the reclaim hoppers to Station 3.

  Station 3:
  At Station 3, coal is transferred to conveyors that transport the coal to Station 4.

  Station 4:

At Station 4, coal is sampled and then transferred to either the Unit 2 silo filling system or to conveyors that transport the coal to Station 5.
Unit 2 Silo Filling:
Coal that is diverted from Station 4 to the Unit 2 silo filling system is discharged into the Unit 2 silos via a series of conveyors and diversion gates.

Station 5 and Unit 1 Silo Filling:
At Station 5, coal is diverted to a series of conveyors and diversion gates that discharge coal into the Unit 1 silos.

Emergency Conveyor System:
Emergency conveyor systems, located above the Unit 1 and Unit 2 silos provide emergency filling of the silos if, for any reason, the primary system is inoperable.

Methods of Compliance:
Fugitive emissions from the coal handling and storage systems are controlled by various methods. Typical measures employed at Mitchell Plant to control fugitive dust emissions from the coal handling and coal storage facilities include, but are not limited to: full and partial transfer point enclosures, coal wetting, full and partially covered conveyors, compaction, and delivery management techniques. The delivery management techniques generally minimize the amount of coal in storage: however, coal delivery capabilities and practices may vary throughout the year. For example, stockpiles may be periodically increased in size in anticipation of coal unloader outages or temporary mining shutdowns. The Mitchell Plant employs management techniques to control and minimize fugitive emissions from the coal handling system and the coal storage areas. The coal handling and storage areas are inspected periodically in accordance with Title V requirements to insure that compliance with fugitive emissions regulations is being maintained.

- **Mitchell Plant Ash Handling:**

Fly Ash Handling Description:
The Mitchell Plant fly ash removal system conveys fly ash collected in the electrostatic precipitator hoppers. Fly ash is then removed from the hoppers by a vacuum conveying system that flows into the dry fly ash handling system. A description of the dry fly ash system follows.

The Mitchell Plant dry fly ash handling system conveys dry, free flowing Fly Ash and Economizer Ash from Units 1 and 2 to three concrete Fly Ash Silos for storage and transport. The overall handling system is composed of three major processes: Unit 1 Fly Ash Removal System, Unit 2 Fly Ash Removal System and the Fly Ash Silo System. Additionally, a dry fly ash landfill and associated haul road are utilized for disposal of the fly ash.

<u>Unit 1 Fly Ash Removal System</u>
The Unit 1 Fly Ash Removal System includes the ash handling Vacuum Conveying System from the precipitator boxes and Economizer hoppers to the Vacuum/Pressure Transfer Stations and the ash handling Pressure Conveying System to the Fly Ash Silos.

There are two Vacuum Conveying Systems, one per precipitator box, provided to convey the ash from the Fly Ash hoppers and the Economizer Ash hoppers (handled by Box 1 ash handling vacuum system) and are operated independently of the other System. Each System is designed to convey to one of two dedicated Vacuum/Pressure Transfer Stations (TS-1A, TS-1B or TS-1C, TS-1D). An automatic Transfer Station crossover exists for each conveying System when one Transfer Station is shut down for maintenance. There are a total of four Transfer Stations for Unit 1. A Transfer Station consists of one Filter/Separator assembly and two feeder assemblies.

The vacuum source for the Vacuum Conveying System is supplied by one of three motor driven Mechanical Exhausters (ME-1A, ME-1B, ME-1C). The three Mechanical Exhausters are connected such that one is dedicated to each System and one is a spare that can be used by either System. The mixture of ash and air is conveyed in conveyor lines in a dry state to the Filter/Separator of the selected Transfer Station where ash is removed from the air stream and dumped into the feeder assemblies for pressure conveying to the Fly Ash Silo System for storage and transport. The Filter/Separator is intended to control particulate emissions from the conveying air. When conveying air leaves the separating equipment, it passes through the Mechanical Exhauster and discharges to atmosphere.

There are two Pressure Conveying Systems, one for each unit (one for unit 1 and one for unit 2) serving a pair of Transfer Stations, provided to convey the ash from the Transfer station feeder assemblies to the Fly Ash Silos. The two systems are operated independently of each other. A common spare pressure conveying line (with automatic crossover) is provided for both conveying Systems. Therefore, there are three pressure conveying lines routed to the Fly Ash Silos.

Conveying air for each Pressure System is supplied by one of three motor driven Fly Ash Conveying Compressors. The three Compressors are connected such that one is dedicated to each System and one is a spare that can be used by either System.

Two feeder assemblies are located under each Filter/Separator. Each feeder assembly receives material from the Filter/Separator at low pressure and introduces it into the pressurized conveyor line. The row of feeder assemblies' empty, in a timed sequence, into the main conveying line. Here, the material is mixed with the conveying air and is transported to the Fly Ash Silos.

The material is collected and stored in the Silos, while the conveying air is vented to atmosphere through a Bin Vent Filter (BVF-A, BVF-B, BVF-C). Each storage silo is equipped with a bin vent filter. The bin vent filter is intended to control particulate emissions from the displaced air that is discharged from the silos. The air discharging through the bin vent filter is a result of the conveying air, dry unloader vent fan air, the air displacement caused by filling the silo with fly ash, the air displacement caused by expansion due to temperature difference, and also from fly ash fluidizing air that is blown into the bottom of the storage silo.

<u>Unit 2 Fly Ash Removal System</u>
The Unit 2 Fly Ash Removal System is similar to the Unit 1 Fly Ash Removal System.
Unit 2 Mechanical Exhausters (ME-2A, ME-2B, ME-2C)
Transfer Stations (TS-2A, TS-2B or TS-2C, TS-2D)

<u>Fly Ash Silo System</u>
The Fly Ash Silo System includes three concrete Fly Ash Silos, each equipped with its own dedicated controlled Silo Fluidizing System, Silo Dry Ash Unloading System and Silo Conditioned Ash Unloading System.

The material collected and stored in the Fly Ash Silos can be unloaded into trucks for removal to a disposal point in either a dry or conditioned state. Ash is unloaded from a Silo in a dry state into a closed-top tank truck with a Telescopic Spout (TC-A, TC-B, TC-C). Each spout is equipped with a vent module (TCV-A, TCV-B, TCV-C). If it is not desired to unload the ash in a dry state, ash is unloaded from a Silo in a conditioned state into an open-top truck with a Pin Paddle Mixer/Unloader (WFA-AA, WFA-BA, WFA-CA, WFA-AB, WFA-BB, WFA-CB). The trucks, containing conditioned fly ash, are used to transport the ash to the Mitchell Plant dry fly ash landfill that was constructed in conjunction with the dry fly ash project.

Bottom Ash Handling Description:
The Mitchell Plant bottom ash removal facilities are designed as wet transport and storage systems and therefore have no fugitive emissions. Slag shed from the furnace walls or dislodged by slage blowers falls through the furnace hopper throats and is collected in ash hoppers. Bottom ash accumulated in the ash hoppers is removed periodically by sluicing it from the hoppers through an ash gate and bottom ash jet pump into an ash disposal line. The ash disposal line carries the mixture to the bottom ash disposal ponds.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Limestone Handling and Processing

Emission unit ID number: Emission Groups 1S	**Emission unit name:** Limestone Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, water sprays.

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The limestone handling system consists of a barge unloader, chutes and conveyors, transfer stations, and storage piles for limestone. See attached description of the limestone handling system.

Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Limestone transfer capacity (nominal) – up to 750 ton/hr

Maximum Hourly Throughput: Nominal 750 ton/hr	**Maximum Annual Throughput:** Nominal 1,100,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes X__ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.67	0.52
Particulate Matter (PM_{10})	4.62	3.68
Total Particulate Matter (TSP)	10.30	8.53
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Sections 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Limestone Handling and Processing Description:

Limestone Handling:
The limestone handling system is the portion of the limestone supply system that is not applicable under 40 CFR 60 Subpart OOO NSPS regulations.

Limestone will be delivered to the Mitchell Plant site in river barges having capacities of up to 2000 tons. New barge docking river cells will be installed parallel to the shoreline near the existing fuel oil unloading pier to store the incoming and outgoing fleet of limestone barges. A barge haul system will be installed to position the barges for unloading. The limestone barge unloading equipment, consisting of a 1000 ton per hour free digging capacity clamshell crane unloader (750 ton per hour average unloading rate), and a receiving hopper/vibratory feeder will be mounted on the new large diameter river cells.

Limestone will be transferred from the clamshell crane Unloader BUN-1 to the fixed, cell mounted hopper RH-1. The hopper RH-1 will discharge via a vibrating feeder VF-1 to the tail end of the limestone dock/connecting conveyor BC-1. The limestone dock/connecting conveyor BC-1 will transfer the limestone from the unloading dock to the first limestone/gypsum Transfer House #1 (TH-1) on shore. Dust will be controlled at the barge unloading operation (hopper load-in area) using a dry fog dust suppression system and windscreens. Nozzles will be mounted around the top of the unloading hopper generating fog to keep any dust generated by dropping the limestone into the hopper, inside the hopper. Further, the dock/connecting conveyor will utilize a ¾ cover to minimize fugitive dust.

At Transfer House TH-1, the limestone will be transferred from the dock/connecting conveyor BC-1 to the storage-pile stacking conveyor BC-2. The stacking conveyor BC-2 will convey the limestone to the active/long-term storage area creating the limestone storage pile (LSSP). The limestone storage pile will be uncovered and have a total capacity of approximately 41,300 tons. The limestone storage pile (LSSP) will have a capacity of approximately 15-days at a generator capacity factor of 100%. The long-term portion of the storage pile will be constructed by moving limestone from the active portion of the pile with mobile equipment to place it in the long-term storage portion of the pile. At the Transfer House TH-1, fugitive dust will be controlled with the use of fully enclosed chutework located within an enclosed building. The chutes incorporate closed loading skirts with adjustable rubber seals to minimize free air flow across the chute. The stacking conveyor BC-2 utilizes a ¾ cover to minimize fugitive dust and discharges to the limestone storage pile LSSP via a concrete stacking tube ST-1.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Limestone Handling and Processing

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, baghouses, water sprays.
Emission Groups 3S	Limestone Processing	

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The limestone processing system consists of chutes and conveyors, transfer stations, ball mills, and silos for limestone. See attached description of the limestone processing system.

Manufacturer:	**Model number:**	**Serial number:**
Various	Custom	N/A
Construction date:	**Installation date:**	**Modification date(s):**
MM/DD/YYYY	See equipment list in Attachment D	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Limestone transfer capacity (nominal) – up to 750 ton/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
Nominal 750 ton/hr	Nominal 1,100,000 ton/yr	8760 hrs/yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes X__ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	1.14	0.82
Particulate Matter (PM_{10})	7.50	5.40
Total Particulate Matter (TSP)	15.85	11.43
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used. The only exception is that baghouse potential emissions were adjusted to reflect a more reasonable potential emission total. Previously, the baghouse emissions were calculated assuming dust loading of the control device was equal to the maximum that the device could handle. The adjustment involves calculating a dust loading that is equal to the maximum that the device will see in the particular installation.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Limestone Processing Description:

Non-Metallic Mineral (Limestone) Processing System:
The "Non-Metallic Mineral Processing" system is the portion of the limestone supply/processing system that is applicable under 40 CFR 60 Subpart OOO NSPS regulations.

Limestone will be reclaimed from the active conical pile through two below grade vibrating pile drawdown hoppers DH-1 and DH-2 that discharge onto two reclaim feeders VF-2 and VF-3. The reclaim feeders VF-2 and VF-3 will discharge onto the tunnel reclaim conveyor BC-3. The tunnel reclaim conveyor BC-3 will discharge onto the silo "A" feed conveyor BC-4. The silo "A" feed conveyor BC-4 terminates in the limestone silo enclosure above the northernmost limestone storage silo LSB-1.

Each of the reclaim feeders (VF-2 and VF-3) will be completely enclosed with loading skirts. The portion of the tunnel reclaim conveyor BC-3 that is located above ground as well as the silo "A" feed conveyor BC-4 utilize ¾ covers to minimize fugitive dust. Each of the transfer points utilizes fully enclosed chutework located within an enclosed building. The chutes incorporate closed loading skirts with adjustable rubber seals between the skirtboard and the loaded belt.

An alternate limestone reclaim system has been designed into the Mitchell project. The alternate reclaim system is used when the reclaim feeders VF-2 and VF-3 are out of service for maintenance or repair or for handling limestone during periods of time that it may be frozen in clumps. The system consists of a feeder/breaker to receive limestone directly from under the storage pile or from an end loader. The feeder/breaker discharges to the limestone tunnel reclaim conveyor BC-3. The limestone tunnel reclaim conveyor can then transfer the limestone to the normal limestone feed conveyors

Limestone from the silo "A" feed conveyor BC-4 can be fed directly into the northernmost limestone silo LSB-1, or can be diverted to the silo "B" feed conveyor BC-5 via a diverter gate. The silo "B" feed conveyor BC-5 will convey the material to limestone silo LSB-2 or to the future silo "C" feed conveyor BC-6 via a diverter gate. Future silo "C" feed conveyor BC-6 will convey limestone to future limestone silo LSB-3. Each of the silo feed conveyors utilize a ¾ cover to minimize fugitive dust and each of the transfer points utilize fully enclosed chutework located within an enclosed building. The chutes incorporate closed loading skirts with adjustable rubber seals between the skirtboard and the loaded belt.

A bagfilter dust collector system will be provided to serve each of the silos. The limestone silo dust collector will have an open bottom and will be mounted on top of the limestone silo. All material collected on the bags falls via gravity into the limestone silo.

Three (including one future) independent FGD reagent preparation trains are provided, supplying complete redundancy support of 24-hour operation. Provisions have been made in the reagent preparation building design to expand the building and add the third (future) reagent preparation train (ball mill, classifier, ball mill product tank, ball mill slurry pumps, etc.) Each of the preparation trains supply limestone slurry to one recirculating feed loop that distributes slurry to both absorbers (one absorber per generating unit).

The limestone silos LSB-1, LSB-2, and LSB-3 (future) are used to store limestone for feed to the grinding system. Limestone drops by gravity from the vibrating bin discharger to the limestone weigh feeder LSWF-1, LSWF-2 and LSWF-3 (future), which conveys the limestone on a belt to the feed chute on the Wet Ball Mill. The limestone weigh feeder is a weighing, variable speed conveyor with its speed adjusted to set the mass flow. Make-up water is added to the feed chute and the mixture enters the wet ball mill.

The wet ball mill is a horizontal cylinder partially filled with steel balls that is rotated, tumbling the balls and grinding the limestone solids. The wet ball mill is motor driven through a gear reducer and is supplied with an air-operated clutch, which is engaged to start the mill once the mill motor is in operation. The clutch may also be used to stop the ball mill operation without stopping the motor. The size of the limestone particles is reduced in the ball mill by a rotating charge of steel balls. The limestone slurry overflows from the ball mill through the mill trommel and gravity feeds to the ball mill slurry tank. Limestone slurry density is maintained by controlling the make-up water flow rate to the classifier underflow launder proportional to the limestone feed rate. Each of the ball mill trains operates as its own separate loop.

The mill slurry pump transfers the limestone slurry from the mill slurry tank to the ball mill classifier. Two 100% ball mill slurry pumps per ball mill slurry tank are provided. Each limestone slurry classifier for the ball mills contains a battery of cyclones with a minimum of 25% spare capacity. The cyclone classifiers are arranged in a circular configuration and are fed from a cylindrical feed chamber. The feed chamber contains no internal partitions, baffles, and/or obstructions and provides a uniform and constant inlet pressure to each cyclone. Fine product slurry is separated from oversized particles of limestone by the classifier. The fine product collected in the overflow launder gravity flows to a common header, which in turn feeds the two limestone reagent slurry storage tanks, while the slurry containing oversized limestone is collected in the underflow launder and gravity flows back to the corresponding ball mill inlet for regrinding.

The two reagent slurry storage tanks are used to maintain a slurry inventory for feed to the absorbers and to provide the minimum suction pressure required by the reagent slurry feed pumps. The reagent slurry storage tank agitator maintains solids in suspension. The reagent slurry feed pump delivers slurry to one of two recirculating feed loop (one operating, one spare). The reagent slurry feed pump maintains a continuously recirculating flow in the loop and slurry velocities are constantly maintained while at the same time providing the required reagent feed to each absorber. Reagent slurry is added to each reaction tank at the base of the absorber in response to the SO2 concentration in the flue gas entering the wet FGD system and the pH of the reaction tank slurry.

The entire processing system beginning at the limestone silo fill point is enclosed in the processing building and all conveyors and transfer points are totally enclosed. Furthermore, the grinding operation occurs in water (slurry) and does not produce dust.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Gypsum Handling			
Emission unit ID number: Emission Groups 2S	**Emission unit name:** Gypsum Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, water sprays.	
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The gypsum handling system consists of a barge loader and unloader, chutes and conveyors, transfer stations, and storage piles for gypsum. See attached description of the gypsum handling system.			
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A	
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY	
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Gypsum transfer capacity (nominal) – up to 1,000 ton/hr.			
Maximum Hourly Throughput: Nominal 1,000 ton/hr	**Maximum Annual Throughput:** Up to Nominal 1,912,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr	
***Fuel Usage Data* (fill out all applicable fields)**			
Does this emission unit combust fuel? ___Yes X__ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired	
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**	
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A			
Describe each fuel expected to be used during the term of the permit.			
Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.74	0.63
Particulate Matter (PM_{10})	11.78	4.38
Total Particulate Matter (TSP)	47.22	9.99
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining potential fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Gypsum Handling Description:

Gypsum Handling:
At the Mitchell facility, gypsum is created as a by-product of the Wet FGD Process. The gypsum will be collected from the four vacuum belt filters (including one future vacuum belt filter) that will discharge onto the Gypsum Vacuum Filter Collecting Conveyor BC-8. The Collecting Conveyor BC-8 will be located inside the dewatering building and will convey the material to the outside of the building and into Transfer House #3 where the gypsum is transferred to the gypsum Connecting Conveyor BC-9.

Connecting Conveyor BC-9 conveys the gypsum from Transfer House #3 to Transfer House #4 where it is transferred to gypsum Connecting Conveyor BC-10. Connecting Conveyor BC-10 conveys the gypsum from Transfer House #4 to Transfer House #5 where it is transferred to gypsum Connecting Conveyor BC-11. Connecting Conveyor BC-11 conveys the gypsum from Transfer House #5 to Transfer House #6 where it is transferred to either gypsum Stacking Tripper Conveyor BC-12 or gypsum Bypass Conveyor BC-13.

The head end of the stacking tripper conveyor BC-12 will be equipped with a traveling tripper able to discharge the gypsum to create the Gypsum Stockpile (GSP). The stockpile will be a 14,200-ton pile to store the gypsum prior to transfer for disposal or use. The gypsum stockpile will be located in a fully enclosed building. At the gypsum stockpile area, the gypsum is reclaimed from the and discharged to gypsum Reclaim Conveyor BC-14. Reclaim Conveyor BC-14 carries the gypsum to Transfer House #7 where it is transferred to gypsum Connecting Conveyor BC-15. As an alternative to carrying the gypsum on BC-14 to Transfer House #7, Reclaim Conveyor BC-14 will be designed as a reversible conveyor. As discussed later in this system description, Reclaim Conveyor BC-14 (operating in tpsrhe reverse mode) will be designed for transfer to a conveyor system supplying gypsum to an alternative destination where it will be utilized by a wallboard manufacturing facility.

As an alternative to placing the gypsum in the stockpile via the stacking tripper conveyor BC-12, Bypass Conveyor BC-13 can be used to transport the gypsum from Transfer House #6 to Transfer House #7 where it is transferred directly to Connecting Conveyor BC-15.

Connecting Conveyor BC-15 conveys the gypsum from Transfer House #7 to Transfer House #1 where is transferred to Transfer Conveyor BC-16. Transfer Conveyor BC-16 conveys the gypsum from Transfer House #1 to the gypsum Barge Loader BL-1. Barge Loader BL-1 transfers the gypsum to waiting river barges via a telescopic chute.

As mentioned previously, as an alternative to carrying the gypsum on BC-14 to Transfer House #7 and on to the barge loader BL-1 for loadout, Reclaim Conveyor BC-14 will be designed as a reversible conveyor. In the reverse mode, Reclaim Conveyor BC-14 will be designed for an extension of the gypsum handling system to allow gypsum transfer to a wallboard plant that will be constructed south of the Mitchell plant on the eastern side of West Virginia State Route 2.

At the gypsum stockpile area, the gypsum is reclaimed from the stockpile and discharged to gypsum Reclaim Conveyor BC-14. Reclaim Conveyor BC-14 (operating in the reverse mode) carries the gypsum to Transfer House TH-8 where it is transferred to gypsum Transfer Conveyor BC-19. Transfer Conveyor BC-19 conveys the gypsum to Transfer House TH-9 where it is transferred to gypsum Transfer Conveyor BC-20. Transfer Conveyor BC-20 conveys the gypsum to Transfer House TH-10 where it is transferred to gypsum Transfer Conveyor BC-21 crossing State Highway 2. Transfer Conveyor BC-21 conveys the gypsum to a future wallboard plant. As an alternative to transferring gypsum from Conveyor BC-20 to BC-21 in Transfer House TH-10, gypsum can also be diverted from Conveyor BC-20 to a small stockpile located at the base of Transfer House TH-10. The gypsum in the small stockpile will be reclaimed with end loaders and placed into dump trucks for transport. The purpose of the Transfer House TH-10 diversion gate and small stockpile is to provide a method of performing a periodic material weight test of the Conveyor BC-19 belt scale by re-weighing the material on a truck scale.

In order to support operation of the third-party wallboard plant, it will be necessary for additional gypsum to be delivered to the Mitchell Plant site in river barges having capacities of up to 1500 tons. The gypsum unloading system will utilize the same barge docking river cells, barge haul system and clamshell barge unloader as the limestone handling system. The barge unloader's clamshell bucket will be changed via a quick disconnect when switching from handling limestone to gypsum.

Gypsum will be transferred from the clamshell unloader BUN-1 to the fixed, cell mounted hopper RH-4. The unloading hopper RH-4 will discharge via a rotary plow RP-1 to the tail end of the gypsum dock/connecting conveyor BC-17. The gypsum dock/connecting conveyor BC-17 will transfer the gypsum from the unloading dock to Transfer House TH-7 on shore. Dust will be controlled at the barge unloading operation (hopper load-in area) using a dry fog dust suppression system and windscreens. Nozzles will be mounted around the top of the unloading hopper generating fog to keep any dust generated by dropping the gypsum into the hopper, inside the hopper.

At Transfer House TH-7, the gypsum will be transferred from the dock/connecting conveyor BC-17 to reclaim conveyor BC-14. As previously noted Reclaim Conveyor BC-14 will be designed as a reversible conveyor. In the reverse mode, Reclaim Conveyor BC-14 will be designed for allow gypsum transfer to a wallboard plant located south of the Mitchell plant as previously described.

As an alternative to transferring the gypsum from dock/connecting conveyor BC-17 to reclaim conveyor BC-14 for transport to the wallboard plant, the gypsum can be temporarily diverted to the gypsum stockpile area awaiting transfer to the wallboard plant. Under this scenario, gypsum from BC-14 is diverted to bypass conveyor BC-18 via diverter gate DG-8 inside Transfer House TH-7. Bypass conveyor BC-18 will transfer the material to stacking conveyor BC-12 inside Transfer House TH-6. As previously described, Stacking Conveyor BC-12, equipped with a traveling tripper, will stack the material into the gypsum stockpile.

Subsequently, as previously described, the gypsum is reclaimed from the stockpile and discharged to gypsum Reclaim Conveyor BC-14. Reclaim Conveyor BC-14 carries the gypsum to the gypsum conveyor extension to the wallboard plant.

Because the gypsum material will be damp (10% moisture by weight) from the filtering process, additional dust collection/suppression equipment is not provided. Nevertheless, the transfer points are designed as fully-enclosed transfer points and each of the outdoor conveyors utilize ¾ covers.

In the event that the normal gypsum handling system or portions of that system are out of service for maintenance/repair or if the gypsum product is of poor quality, provisions are being made to allow for emergency gypsum handling and disposal. The system consists primarily of an emergency stackout conveyor and stockpile. The gypsum collected from the four vacuum belt filters (including one future vacuum belt filter) is capable of being discharged onto the Gypsum Vacuum Filter Collecting Backup Conveyor BC-7. The Backup Collecting Conveyor BC-7 will be located inside the dewatering building and will convey the gypsum to the outside of the building where it will be stacked out to the emergency gypsum stockpile (GSPE). Gypsum stockpiled on the emergency pile will be reclaimed using front-end loaders and placed into dump trucks for transfer and disposal off-site or transfer to the normal gypsum stockpile (GSP). Since the material will be damp (10% moisture by weight) from the filtering process additional dust collection/suppression equipment is generally not necessary. Nevertheless, a ¾ cover will be utilized on the outdoor portion of Backup Collecting Conveyor BC-7.

ATTACHMENT E - Emission Unit Form

Emission Unit Description WWT Handling		
Emission unit ID number: Emission Groups 11S	**Emission unit name:** WWT Handling	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures, baghouses, water sprays.
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The waste water treatment handling system consists of truck unloading equipment, chutes and conveyors, transfer stations, lime storage silos, and storage piles for WWT cake. See attached description of the WWT handling system.		
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): WWT Cake transfer capacity (nominal) up to 600 ton/hr.		
Maximum Hourly Throughput: Nominal 600 ton/hr	**Maximum Annual Throughput:** Nominal 212,000 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr
***Fuel Usage Data* (fill out all applicable fields)**		
Does this emission unit combust fuel? ___Yes X__ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A		
Describe each fuel expected to be used during the term of the permit.		

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	14.95	0.87
Particulate Matter (PM_{10})	98.90	5.83
Total Particulate Matter (TSP)	219.56	14.63
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining potential fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

WWT Handling Description:

Waste Water Treatment Handling System:
The Wastewater Treatment System is used to treat the FGD wastewater prior to discharge of the water into the plant wastewater ponds. The wastewater treatment system is designed to reduce the effluent total suspended solids (TSS) concentration and maintain pH within an acceptable range. In addition to the TSS reduction, the treatment system is designed to be retrofitted should dissolved metals removal be required in the future. A generic treatment system process flow diagram has been supplied with this permit application.

The wastewater treatment system process includes equipment for dissolved sulfate desaturation, primary clarification, chemical addition, mixing and reaction, secondary clarification and filtration. Chemicals are added to the wastewater stream to improve the removal efficiency of the waste stream solids. The solids removed from the water stream are dewatered and stored for disposal. Dewatering is accomplished by filter presses (four, including one future). The design includes a provision to add a polymer at the inlet to the secondary clarifiers if required. Filter cake storage is in concrete bins, or rooms located beneath the filter presses. After desired dryness is achieved, the dewatered filter cake drops through a hole in the floor to a dewatered filter cake storage room. The projected amount of filter cake that will be generated on an annual basis is 212,000 tons/year.

Hydrated lime will be delivered to the site by pneumatic truck equipped with its own positive displacement rotary blower. The lime will be stored on site in two lime storage silos. A bag type bin vent filter, rated at 99.9 percent removal efficiency, will be provided to control escape of dust during transfer. Lime feeders and mix tanks will be located inside an enclosure below the silos.

Along with the lime, several other liquid chemicals will be delivered for use in the wastewater treatment system. These include ferric chloride and acids delivered by bulk tank truck along with organosulfate (future), and a polymer delivered by totes.

Disposal of the filter cake that will be generated by the wastewater treatment system will be accomplished by either placing the material in a barge, or in emergency situations, trucks for transport from the plant site. Each of the cake storage rooms (four) located beneath the filter presses (three with provisions for the fourth) will be open at one of the narrow ends for access by front-end loaders (i.e. the building enclosure consists of three walls and a roof). The filter cake will be removed by front-end loader and deposited into a covered stockpile at the loading end of a feeder/breaker FB-2, (drag flight-type conveyor). Feeder/breaker FB-2 will transport filter cake to the loading end of Transfer Conveyor BC-22 (belt type conveyor). Transport conveyor BC-22 will transport and discharge onto transfer conveyor BC-15 at Transfer House TH-12. Transfer conveyor BC-15 conveys the filter cake to Transfer House TH-1 where it is transferred to Transfer Conveyor BC-16. Transfer Conveyor BC-16 conveys the filter cake from Transfer House TH-1 to the Barge Loader BL-1. Barge Loader BL-1 transfers the filter cake to covered river barges via telescopic chute TC-1. Feeder/breaker FB-2 and Transfer Conveyor BC-22 will limit the maximum load out capacity to 600 tons per hour.

Filter cake storage will be accommodated inside the storage rooms (maximum of 900 tons each) beneath the filter presses as well as at the covered loading area of the feeder/breaker (300 tons). In the event barge load out of the filter cake is disrupted (i.e. high river water conditions stopping barge traffic) and the covered filter cake storage areas are filled, trucks will be used to transport the filter cake to GSPE, the gypsum emergency stockpile area, (2500 tons) normally used for gypsum and covered by tarps. In the extreme condition that the stockpile area is filled or if the facility is able to find a third party interested in purchasing the filter cake, trucks will be used to transport the filter cake off-site.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Coal Blending System

Emission unit ID number: Emission Group 5S	**Emission unit name:** Coal Blending System	**List any control devices associated with this emission unit:** Conveyor covers, partial and full enclosures.

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The coal blending system consists of a chutes and conveyors, transfer stations, and storage piles for coal. See attached description of the coal blending system.

Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): Coal transfer capacity (nominal) – up to 3,000 ton/hr.

Maximum Hourly Throughput: Nominal 3,000 ton/hr	**Maximum Annual Throughput:** Nominal 5,732,544 ton/yr	**Maximum Operating Schedule:** 8760 hrs/yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes X__ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

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Emissions Data

Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	3.65	4.76
Particulate Matter (PM_{10})	24.08	31.46
Total Particulate Matter (TSP)	50.92	66.52
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory limits, and engineering knowledge. For purposes of determining potential fugitive emissions associated with this system, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.0 through Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.2 through 6.6 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Coal Blending System Description:

Coal Blending:
At the Mitchell Plant, the installation of the Wet FGD Process will allow the facility to burn a high-sulfur coal potentially available from a local mine. Nevertheless, it will likely be necessary to blend this high sulfur coal with a lower sulfur coal in order to obtain the coal qualities necessary for long-term, reliable combustion of the coal in the Mitchell Units. As such, a coal blending system is planned as an integral part of the FGD retrofit project.

The locally mined coal will enter the Mitchell site via the existing Consol Conveyor 3100. Conveyor 3100's discharge will be modified to transport the coal into the Mitchell coal handling system Transfer Station 1 (HTS-1). In Transfer Station #1, coal will be transferred from Conveyor 3100 to Stacking Conveyor HSC-1. Stacking Conveyor HSC-1 will transport the coal from Transfer Station #1 to Transfer Station #2A (HTS-2A) where the coal will be sampled and transferred to Stacking Conveyor HSC-2. Stacking Conveyor HSC-2 will transport the coal from Transfer Station #2A to Transfer Station #3 (HTS-3) where the coal will be transferred to Stacking Conveyor HSC-3. As an alternative, coal can be transferred to Stacking Conveyor HSC-3 from existing plant radial stacker R9 via Stacking Hopper SH-1.

Stacking Conveyor HSC-3 transfers the coal from Transfer Station #3 to the existing North Yard Storage area where it will be discharged through a new Stacking Tube (ST-1) to help form the high sulfur coal pile.

Coal will be reclaimed from the high sulfur coal pile via four under-pile drawdown hoppers/vibratory feeders. Each of the four vibratory feeders (HVF-1 through HVF-4) transfer coal to Tunnel Reclaim Conveyor HRC-1. Tunnel Reclaim Conveyor HRC-1 transfers the coal from under the pile to Transfer Station #2B where it is transferred to Reclaim Conveyor HRC-2. Reclaim Conveyor HRC-2 will transport the coal from Transfer Station #2 to Transfer Station #4 (HTS-4) where the coal will be transferred to Reclaim Conveyor HRC-3.

Reclaim Conveyor HRC-3 will transport the coal from Transfer Station #4 to Transfer Station #5 where it will discharge via a surge bin (SB-1) to two Belt Feeders (HBF-1A and HBF-1B). Belt Feeder HBF-1A will discharge coal onto existing plant coal conveyor 4E. Belt Feeder HBF-1B will discharge coal onto existing plant coal conveyor 4W. The blending of high sulfur coal with the lower sulfur coal will occur as the high sulfur coal is discharged from Belt Feeders HBF-1A and HBF-1B onto the existing conveyors 4E and 4W that carry low sulfur coal from the existing low sulfur coal pile.

In order to minimize fugitive dust generated from the coal blending system, each of the new transfer points will utilize fully enclosed chutework located within fully enclosed buildings. Furthermore, all outdoor conveyors will utilize ¾ covers. To further minimize fugitive dust generated from the coal blending system, conveyor to conveyor transfers will utilize controlled flow transfer chutes.

An alternate high sulfur coal reclaim system has been designed into the Mitchell project. The alternate reclaim system is used when the reclaim feeders (HVF-1 through HVF-4) are out of service for maintenance/repair or in the event it is necessary to separate frozen chunks of coal. The system consists of a feeder/breaker (FB) to receive coal directly from under the storage pile or from a front-end loader. The feeder/breaker discharges to the high sulfur coal tunnel reclaim conveyor (HRC-1). The high sulfur coal tunnel reclaim conveyor can then transfer the coal to the normal high sulfur coal reclaim conveyors.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Emergency Quench Water System		
Emission unit ID number: Emission Units 6S and 7S	**Emission unit name:** Emergency Quench Water System	**List any control devices associated with this emission unit:** Full enclosures.
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The emergency quench water system consists of two diesel-engine driven quench pumps. See attached description of the emergency quench water system.		
Manufacturer: Clark Diesel	**Model number:** JU 4R-UF-19 or equal	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 60 HP (approx.),		
Maximum Hourly Throughput: 5.5 gal./hr (each)	**Maximum Annual Throughput:** 1,100 gal./yr (combined)	**Maximum Operating Schedule:** 200 hrs/yr (both engines combined)
***Fuel Usage Data* (fill out all applicable fields)**		
Does this emission unit combust fuel? _X_Yes ___ No		**If yes, is it?** _X_ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 0.8 mmBtu/hr nominal, 60 HP		**Type and Btu/hr rating of burners:**
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. Diesel Fuel		

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	0.2%	N/A	141,000 Btu/gal

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	1.52	0.08
Nitrogen Oxides (NO_X)	7.06	0.35
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.5	0.02
Particulate Matter (PM_{10})	0.5	0.02
Total Particulate Matter (TSP)	0.5	0.02
Sulfur Dioxide (SO_2)	0.46	0.02
Volatile Organic Compounds (VOC)	0.76	0.04
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors and manufacturer's information. For purposes of determining emissions associated with this equipment, the FGD Reg 13 permit application (permit R13-2608A) calculations were used. The estimated potential emissions represent the total emissions for both quench pumps combined.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 7.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 7.2 through 7.5 (see Attachment I): Where appropriate, revisions to existing language are noted
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Emergency Quench Water System Description:

Emergency Quench Water:
The existing air heaters are electric powered which could fail in case of plant power failure. In this case, the hot flue gas (600oF) could enter the absorbers. The emergency quench water system is designed to protect the absorbers by spraying water into the flue gas entering the absorber. The emergency quench system is activated in the event of a loss of on-site power. Two 100% pumps (including one spare) are provided for redundancy. The pumps are diesel engine driven to allow operation during blackout conditions. The service water tank provides the water supply.

Each emergency quench pump drive engine is rated at approximately 60 HP. No post-combustion pollution controls are utilized. Because these diesel engines are each rated at less than 500 brake horsepower, the engines are not subject to regulation under 40 CFR 63 Subpart ZZZZ (RICE rule).

The diesel fuel is supplied from a storage tanks holding approximately 70 gallons of fuel (one for each engine). Because the diesel fuel storage tanks are each less than 10,567 gallons capacity and will contain petroleum or organic liquids with a vapor pressure of 1.5 psia or less at storage temperature, and the emissions from both tanks, in the aggregate, are less than 2 tons per year, the tanks are considered de-minimis sources. De-minimis sources are not required to obtain construction permits under 45 CSR 13.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Dry Sorbent Handling System		
Emission unit ID number: Emission Group 4S	**Emission unit name:** Dry Sorbent Handling Systems	**List any control devices associated with this emission unit:** Full enclosures, baghouses.
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The dry sorbent handling system consists of truck unloading equipment, dry sorbent storage silos, etc. See attached description of the dry sorbent handling system.		
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 25 TPH Unloading, 500 Ton Dry Sorbent Silos		
Maximum Hourly Throughput: Nominal 25 ton/hr	**Maximum Annual Throughput:** Dry Sorbent 81,000 TPY Nominal	**Maximum Operating Schedule:** 8760 Hr/Yr
***Fuel Usage Data* (fill out all applicable fields)**		
Does this emission unit combust fuel? ___Yes _X_ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A		

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	31.31	136.86
Particulate Matter (PM_{10})	206.77	903.82
Total Particulate Matter (TSP)	438.69	1912.18
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory/permit limits and engineering knowledge. For purposes of determining potential fugitive emissions associated with this equipment, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Dry Sorbent Handling System Description:

SO_3 Mitigation System:
The installation and operation of a Selective Catalytic Reduction (SCR) system in conjunction with a wet FGD system on a boiler combusting high sulfur coal can potentially lead to increased concentrations of SO_3. Subsequently, the SO_3 reacts with moisture in the stack plume and the atmosphere to support the secondary formation of H_2SO_4. If not mitigated, the increase in SO_3 and subsequent increase in the formation of H_2SO_4 can impact the visible appearance of the discharge plume downwind of the stack.

The Mitchell Plant SCR installation utilizes a low conversion catalyst that helps minimize the conversion of SO_2 to SO_3 by the SCR system. Nevertheless, a supplemental SO_3 mitigation system is needed to help reduce SO_3 concentrations. Based on AEP's evaluation of various SO_3 mitigation systems at other AEP generating facilities, it was determined that the primary SO_3 mitigation system that would be constructed at Mitchell plant was a dry sorbent injection system. Hydrated Lime is the primarily used dry sorbent, with Trona being the secondary option. When Hydrated Lime is used, the dry sorbent injection system is supplemented with the injection of liquid Magnesium Hydroxide. For the purposes of this permit application, each of the options is described.

Dry Sorbent Handling:
The dry sorbent is injected through a pneumatic conveying system to ductwork downstream of the air preheaters as a means to reduce SO_3 in the stack plume. The dry sorbent feed rate for each Mitchell Unit will vary depending on the sorbent (Trona or Hydrated Lime) being utilized and the sulfur content of the fuel. The Trona feed rate is variable with an expected maximum feed of up to 4.6 tons per hour (per unit). The Hydrated Lime feed rate is also variable with an expected maximum feed of up to 4.4 tons per hour (per unit).

Two dry sorbent storage silos at approximately 500 tons each receive dry sorbent from self-unloading trucks. Bin vent filters are supplied on each silo for the filtered venting of the truck blow-off air and the silo's fluidizing air system. An aeration system, consisting of open-type airslides, with operating and standby aeration blowers and routing valves supplies air to the silos, distribution bin, airslides, and de-aeration bins.

Dry sorbent is discharged out of the silo through a distribution bin and airslides into two de-aeration bins. The de-aeration bins are periodically filled and serve to control the fluidity of the material and minimize the head pressure that the material imposes on the downstream variable speed rotary feeders.

The feed stack-up below each de-aeration bin consists of a variable speed rotary feeder, vent hopper, fixed-speed rotary airlock, and material pick-up tee. There are two such stack-ups (one in-service and one stand-by), each with the capability to feed the primary conveying line. A pneumatically operated isolation valve is included at the discharge of the silo bin.

The dry sorbent is fed through a piping system (conveying lines) to injection lances located in the duct downstream of the air preheaters. Conveying air is supplied by three blower skid packages (two operating and one as standby) isolated by air-operated valves. Dry, high-pressure air is supplied for purging the bearings on the rotary feeders and airlocks and for pulsation cleaning of the bags in the bin vent filter at the top of each silo.

Because the dry sorbent handling system is a totally enclosed system using pressurized air as the carrying medium, particulate emissions are eliminated with the exception of those that are emitted as a result of truck traffic and from the baghouses installed on the storage silos. On a short-term basis, truck deliveries of dry sorbent are expected to be up to 2 per hour. At full load conditions, approximately 1550 tons of dry sorbent are potentially required per week. This equates to approximately 3215 trucks per year assuming a 100% capacity factor.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Magnesium Hydroxide Handling System

Emission unit ID number: Emission Group 9S	**Emission unit name:** Magnesium Hydroxide Handling Systems	**List any control devices associated with this emission unit:** Full enclosures

Provide a description of the emission unit (type, method of operation, design parameters, etc.):
The magnesium hydroxide handling systems consists of truck unloading equipment, mag. hydroxide mix tanks, etc. See attached description of the magnesium hydroxide handling system.

Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 1,000 gallon mag. hydroxide mix tanks (2)

Maximum Hourly Throughput: 8000 gal/hr delivered	**Maximum Annual Throughput:** Mag. Hyd. 6,600,000 Gal./yr	**Maximum Operating Schedule:** 8760 Hr/Yr

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ___Yes _X_ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.08	0.03
Particulate Matter (PM_{10})	0.51	0.21
Total Particulate Matter (TSP)	2.61	1.08
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory/permit limits and engineering knowledge. For purposes of determining potential fugitive emissions associated with this equipment, the FGD Reg 13 permit application (permit R13-2608A) calculations were used.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.1 (see Attachment I): Where appropriate, revisions to existing language are noted.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time.

Requirements currently captured in Title V permit:

R30-05100005-2019 (MM01) Section 6.2 through 6.4 (see Attachment I): Where appropriate, revisions to existing language are noted.

Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Magnesium Hydroxide Handling System Description:

SO_3 Mitigation System:
The installation and operation of a Selective Catalytic Reduction (SCR) system in conjunction with a wet FGD system on a boiler combusting high sulfur coal can potentially lead to increased concentrations of SO_3. Subsequently, the SO_3 reacts with moisture in the stack plume and the atmosphere to support the secondary formation of H_2SO_4. If not mitigated, the increase in SO_3 and subsequent increase in the formation of H_2SO_4 can impact the visible appearance of the discharge plume downwind of the stack.

The Mitchell Plant SCR installation will utilize a low conversion catalyst that will help to minimize the conversion of SO_2 to SO_3 by the SCR system. Nevertheless, it is anticipated that a supplemental SO_3 mitigation system will be needed to help reduce SO_3 concentrations. Based on AEP's evaluation of various SO_3 mitigation systems at other AEP generating facilities, it has been determined that the primary SO_3 mitigation system that will be constructed at Mitchell plant will be a dry sorbent injection system. Hydrated Lime is the primarily used dry sorbent, with Trona being the secondary option. When Hydrated Lime is used, the dry sorbent injection system is supplemented with the injection of liquid Magnesium Hydroxide. For the purposes of this permit application, each of the options is described.

Magnesium Hydroxide Injection:
The purpose of magnesium hydroxide injection is to assist in the mitigation of SO_3 in the furnace in the event that Trona dry sorbent injection in not being used. If hydrated lime dry sorbent is injected into the flue gas downstream of the air preheater, magnesium hydroxide injection into the furnace will likely be needed to assist in the mitigation of SO_3. Magnesium hydroxide, if use, will be injected into the furnace as a 15% magnesium hydroxide/water slurry. Approximately 1.5 tons per hour (per unit) of magnesium hydroxide will be required for 90% SO_3 mitigation.

The magnesium hydroxide will be delivered to the Mitchell Plant site by tanker truck in a 60% magnesium hydroxide/water slurry and pumped into one of two storage tanks. The 60% solution is then pumped into a small mixing tank where it will be diluted with filtered water to a 15% slurry. The 15% slurry is then pumped to the furnaces and injected. The tanker trucks are expected to have a nominal capacity of approximately 4000 gallons. The only emissions associated with this material handling system will be fugitive particulate emissions associated with the delivery truck traffic on the plant site. On a short-term basis, tanker truck deliveries for the magnesium hydroxide system are expected to be up to 2 per hour.

At full load conditions, approximately 18,000 gallons of 60% slurry will be required per day. This equates to approximately 1650 truckloads of liquid magnesium hydroxide per year assuming a 100% capacity factor.

ATTACHMENT E - Emission Unit Form			
Emission Unit Description ***Urea Handling System***			
Emission unit ID number: N/A	**Emission unit name:** Urea Handling Systems	**List any control devices associated with this emission unit:** Full and partial enclosures.	
Provide a description of the emission unit (type, method of operation, design parameters, etc.): The urea handling systems consists of truck unloading equipment, screw conveyor, mix tanks, etc. See attached description of the urea handling system.			
Manufacturer: Various	**Model number:** Custom	**Serial number:** N/A	
Construction date: MM/DD/YYYY	**Installation date:** See equipment list in Attachment D	**Modification date(s):** MM/DD/YYYY	
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 48 Ton Unloading Hopper, 200,000 gal. Urea Storage Tank.			
Maximum Hourly Throughput: Nominal 50 ton/hr	**Maximum Annual Throughput:** Dry urea 26,000 TPY Nominal,	**Maximum Operating Schedule:** 8760 Hr/Yr	
Fuel Usage Data **(fill out all applicable fields)**			
Does this emission unit combust fuel? ___Yes _X_ No		**If yes, is it?** ___ Indirect Fired ___Direct Fired	
Maximum design heat input and/or maximum horsepower rating: N/A		**Type and Btu/hr rating of burners:**	
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. N/A			
Describe each fuel expected to be used during the term of the permit.			
Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
N/A	N/A	N/A	N/A

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.036	0.009
Particulate Matter (PM_{10})	2.47	0.64
Total Particulate Matter (TSP)	6.93	1.8
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Potential emissions are based on a combination of AP-42 emission factors, regulatory/permit limits and engineering knowledge.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** **X.0. Source-Specific Requirements [Urea Handling (*Emission points listed in section 1.0. Table*)]** **X.1. Limitations and Standards** The Urea handling system is subject to 45CSR§2-5 as outlined in the facility wide section of this permit (condition 3.1.9) regarding fugitive dust control system.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** **X.2. Monitoring, Recordkeeping, and Reporting Requirements** See Permit conditions 3.4 and 3.5 in the facility wide section of this permit. [45 CSR 30-5.1.c]
Are you in compliance with all applicable requirements for this emission unit? X__Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Dry Sorbent and Magnesium Hydroxide Handling System Description:

Urea Handling System:
Ammonia is the reagent used in the SCR process to reduce the NO_x, produced in the combustion process to elemental nitrogen and water vapor. The ammonia is generated from the Urea to Ammonia ($U2A^{TM}$) system. The $U2A^{TM}$ system uses dry urea as the feedstock to produce ammonia vapor by hydrolyzing a urea solution to form ammonia vapor, carbon dioxide and water vapor. The urea solution is prepared from dry urea and steam condensate water.

The dry urea unloading system includes the equipment necessary to unload dry urea from trucks and transport it to urea solution mix tank. There is a provision to receive two 25-ton truckloads of dry urea back to back in a hopper located in a pit constructed by AEP at the Truck Unloading Station. Dry urea is then transferred from the hopper to a urea solution mix tank via full enclosed screw/drag conveyor equipment. In the mix tank, urea and condensate water is added in sufficient quantities to convert the dry urea into a 40% (by weight) urea solution for use in the urea to ammonia conversion process. The design is suitable for either prill or granular urea. The urea solution is transferred from the mix tank to a urea solution storage tank for use by the $U2A^{TM}$ system.

ATTACHMENT E - Emission Unit Form

Emission Unit Description Diesel Engine Driven Coping Power Emergency Generators (EG-1 and EG-2)		
Emission unit ID number: EG-1 EG-2	**Emission unit name:** Diesel Driven Coping Power Emergency Generators EG-1 and EG-2	**List any control devices associated with this emission unit:**N/A
Provide a description of the emission unit (type, method of operation, design parameters, etc.): These are large diesel driven emergency generators. One rated at 3,717 bhp (EG-1) and one rated at 3,0004 bhp (EG-2). The generators are intended to provide facility auxiliary power in the event of a regional power grid outage.		
Manufacturer: Caterpillar	**Model number:** C175-16 (EG-1); 3516C-HD TA (EG-2)	**Serial number:**
Construction date: 08/2014	**Installation date:** 08/2014	**Modification date(s):** MM/DD/YYYY
Design Capacity (examples: furnaces - tons/hr, tanks - gallons): 3,717 bhp (EG-1) and 3,0004 bhp (EG-2)		
Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
Fuel Usage Data **(fill out all applicable fields)**		
Does this emission unit combust fuel? _X_Yes ___ No		**If yes, is it? RICE** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 3,717 bhp (EG-1) at 1800rpm 3,0004 bhp (EG-2) at 1800rpm		**Type and Btu/hr rating of burners:**
List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each. Diesel Fuel		

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15ppm		

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Emissions Data

Criteria Pollutants	Potential Emissions			
	PPH		TPY	
	EG-1	EG-2	EG-1	EG-2
Carbon Monoxide (CO)	7.66	4.85	1.92	1.21
Nitrogen Oxides (NO_X)	59.9	36.4	14.98	9.1
Lead (Pb)				
Particulate Matter ($PM_{2.5}$)	0.05	0.04	0.01	0.01
Particulate Matter (PM_{10})	0.35	0.26	0.09	0.06
Total Particulate Matter (TSP)	0.44	0.33	0.11	0.08
Sulfur Dioxide (SO_2)	0.01	0.01	0.06	0.05
Volatile Organic Compounds (VOC)	0.94	1.18	0.24	0.3

Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY

Regulated Pollutants other than Criteria and HAP	Potential Emissions			
	PPH		TPY	
CO2	3961	3185	990.3	796.3

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, CO, VOC, PM10 and CO2. AP-42 used for SO2

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. The following permit conditions are considered the applicable requirements for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. Where appropriate, calculation basis is provided. For existing limits that were previously captured in the permit, the calculations were provided in the previous permit application(s). No changes to existing limits are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 8.0 through 8.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
____ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) The following permit conditions are considered the applicable requirements for monitoring, testing, recordkeeping and reporting for this emission unit. Where appropriate, the actual permits are attached to provide the applicable language along with the underlying rule/regulatory citation. No changes are being requested at this time. **Requirements currently captured in Title V permit:** R30-05100005-2019 (MM01) Sections 8.2 through 8.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? _X_Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description		
Emission unit ID number: 17S	**Emission unit name:** Unit 1 Emergency Diesel Driven Fire Pump	**List any control devices associated with this emission unit:** N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Emergency diesel driven fire pump that replaced existing unit associated with Unit 1 at the plant. 249 BHP diesel engine.

Manufacturer: Cummins	**Model number:** CFP7E-F60 Fire Pump / QSB6.7 Engine	**Serial number:**
Construction date: MM/DD/YYYY 08/2023	**Installation date:** MM/DD/YYYY 08/2023	**Modification date(s):** MM/DD/YYYY 08/2023

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):
Approx. 14 gal/hr, 249 BHP

Maximum Hourly Throughput: Approx. 14 gal/hr	**Maximum Annual Throughput:** 7,000 gal/yr	**Maximum Operating Schedule:** Assumed 500 hr/yr, but not limited during emergency

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☑ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 249 BHP	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15 ppm sulfur.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		Approx. 137,030 btu/gal

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.65	0.16
Nitrogen Oxides (NO_X)	1.36	0.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.06	0.015
Particulate Matter (PM_{10})	0.06	0.015
Total Particulate Matter (TSP)	0.06	0.015
Sulfur Dioxide (SO_2)	0.51	0.128
Volatile Organic Compounds (VOC)	0.63	0.16
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY
CO2	286.35	71.59

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, PM, and CO. AP-42 used for SO2, CO2, and VOC.

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Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L.

Requirements currently captured in Title V permit:
R30-05100005-2019 (MM01) Section 7.1.

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For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L.

Requirements currently captured in Title V permit:
R30-05100005-2019 (MM01) Sections 7.2 through 7.5.

Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description		
Emission unit ID number: 18S	**Emission unit name:** Unit 2 Emergency Diesel Driven Fire Pump	**List any control devices associated with this emission unit:** N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Emergency diesel driven fire pump that will replace existing unit associated with Unit 2 at the plant. 249 BHP diesel engine.

Manufacturer: Cummins	**Model number:** CFP7E-F60 Fire Pump / QSB6.7 Engine	**Serial number:**
Construction date: MM/DD/YYYY 06/2024	**Installation date:** MM/DD/YYYY 06/2024	**Modification date(s):** MM/DD/YYYY 06/2024

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Approx. 14 gal/hr, 249 BHP

Maximum Hourly Throughput: Approx. 14 gal/hr	**Maximum Annual Throughput:** 7,000 gal/yr	**Maximum Operating Schedule:** Assumed 500 hr/yr, but not limited during emergency

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☑ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 249 BHP	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15 ppm sulfur.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		Approx. 137,030 btu/gal

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.65	0.16
Nitrogen Oxides (NO_X)	1.36	0.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.06	0.015
Particulate Matter (PM_{10})	0.06	0.015
Total Particulate Matter (TSP)	0.06	0.015
Sulfur Dioxide (SO_2)	0.51	0.128
Volatile Organic Compounds (VOC)	0.63	0.16
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY
CO2	286.35	71.59

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, PM, and CO. AP-42 used for SO2, CO2, and VOC.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Section 7.1.
☐ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Sections 7.2 through 7.5.
Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description		
Emission unit ID number: LF DEG	**Emission unit name:** LF DEG	**List any control devices associated with this emission unit:** N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.):

Landfill Leachate Collection Sump Diesel Emergency Generator with integral 600 gallon diesel fuel tank. 300kw generator, 464 Bhp diesel engine.

Manufacturer: Cummins	**Model number:** C300DQDAC gen/QSL9-G7 engine	**Serial number:**
Construction date: (MM/DD/YYYY) 04 / / 2020	**Installation date:** (MM/DD/YYYY) 04 / / 2020	**Modification date(s):** (MM/DD/YYYY) / / ; / / / / ; / /

Design Capacity (examples: furnaces - tons/hr, tanks - gallons):
approx. 23.1 gal/hr, 464 Bhp, 600 gal associated fuel tank.

Maximum Hourly Throughput: approx 23.1 gal/hr	**Maximum Annual Throughput:** 11,550 gal/yr	**Maximum Operating Schedule:** assumed 500 hr/yr,but not limited during emergency

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ✔ Yes ___ No	**If yes, is it?** ___ Indirect Fired ___Direct Fired
Maximum design heat input and/or maximum horsepower rating: 464 Bhp	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than15ppm S.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		approx. 137,030 btu/gal

Page______of ______

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.31	0.08
Nitrogen Oxides (NO_X)	5.37	1.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.03	0.008
Particulate Matter (PM_{10})	0.03	0.008
Total Particulate Matter (TSP)	0.03	0.008
Sulfur Dioxide (SO_2)	0.11	0.028
Volatile Organic Compounds (VOC)	1.17	0.292
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, CO, SO2, and PM. AP-42 used for VOC.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. Requirements currently captured in Title V Permit: R30-05100005-2019 (MM01) Section 8.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
___Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) Requirements currently captured in Title V Permit: R30-05100005-2019 (MM01) Sections 8.2 through 8.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? _✔_Yes ___No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	Emission unit name:	List any control devices associated with this emission unit:
LF DEG2	LF DEG2	n/a

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Diesel driven 400kw, 513 Bhp, mobile emergency generator to be used at the Landfill Leachate Storage Pond

Manufacturer:	Model number:	Serial number:
Cummins	QSG12	

Construction date: MM/DD/YYYY	Installation date: MM/DD/YYYY	Modification date(s): MM/DD/YYYY
07/2023	07/2023	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

approx 23.2 gal/hr, 513 Bhp, 470 gallon fuel tank

Maximum Hourly Throughput:	Maximum Annual Throughput:	Maximum Operating Schedule:
approx 23.2 gal/hr	11,600 gal/yr	assumed 500hr/yr but not limited during emergency

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No

If yes, is it? ☐ Indirect Fired ☐ Direct Fired

Maximum design heat input and/or maximum horsepower rating:

513 Bhp

Type and Btu/hr rating of burners:

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15ppm S.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		approx 137,030 btu/gal

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Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.08	0.02
Nitrogen Oxides (NO_X)	0.14	0.04
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.01	0.002
Particulate Matter (PM_{10})	0.01	0.002
Total Particulate Matter (TSP)	0.01	0.002
Sulfur Dioxide (SO_2)	0.11	0.026
Volatile Organic Compounds (VOC)	1.29	0.322
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, CO, and PM. AP-42 used for SO2 and VOC.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Section 8.1 (see Attachment I): Where appropriate, revisions to existing language are noted.
☐ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Sections 8.2 through 8.5 (see Attachment I): Where appropriate, revisions to existing language are noted.
Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Attachment G

Air Pollution Control Device Forms

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:
ML1 ESP

List all emission units associated with this control device.
Unit 1

Manufacturer:
Wheelabrator Frye

Model number:
1487

Installation date:
12/30/1977

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare ___ Other (describe) ________________

___ Wet Plate Electrostatic Precipitator _X_ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
PM	100%	99.85%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Avg. Pressure Drop = 0.07 inches H_2O, Avg. Gas Flow Rate = $3{,}000 \times 10^3$ acfm, Avg. Operating temp. = 370 ^oF, Design Removal Efficiency = 99.85%

Is this device subject to the CAM requirements of 40 C.F.R. 64? _X_ Yes __ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitor opacity as an indicator of electrostatic precipitator performance. Periodic stack tests are performed to assure compliance with the particulate mass emissions standard.

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:
ML1 FGD

List all emission units associated with this control device.
Unit 1

Manufacturer:
B&W

Model number:
Custom

Installation date:
04/28/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) _X_ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare ___ Other (describe) ________________

___ Wet Plate Electrostatic Precipitator ___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
SO_2	100%	95%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Full Load Flow Rate = 2.6×10^6 acfm, Outlet temperature = 128 °F, Design Removal Efficiency = 95%

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of SO_2 emissions using CEMS

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML1 SCR	**List all emission units associated with this control device.** Unit 1	
Manufacturer:	**Model number:** Custom	**Installation date:** 05/02/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare __X Other (describe) Selective Catalytic Reduction

___ Wet Plate Electrostatic Precipitator ___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
NO_x	100%	90%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).
NOx Control Efficiency = 90.0%, Design Temperature = 750 ºF, Maximum ammonia slip = 2 ppmvd at 3% O_2

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of NO_x emissions using CEMS

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:
ML2 ESP

List all emission units associated with this control device.
Unit 2

Manufacturer:	**Model number:**	**Installation date:**
Wheelabrator Frye	1487	06/16/1978

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare ___ Other (describe) ________________

___ Wet Plate Electrostatic Precipitator _X_ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
PM	100%	99.85%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Avg. Pressure Drop = 0.07 inches H_2O, Avg. Gas Flow Rate = $3{,}000\text{x}10^3$ acfm, Avg. Operating temp. = 370 °F, Design Removal Efficiency = 99.85%

Is this device subject to the CAM requirements of 40 C.F.R. 64? _X_ Yes __ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitor opacity as an indicator of electrostatic precipitator performance. Periodic stack tests are performed to assure compliance with the particulate mass emissions standard.

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML2 FGD	**List all emission units associated with this control device.** Unit 2	
Manufacturer: B&W	**Model number:** Custom	**Installation date:** 01/15/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter	___ Venturi Scrubber	___ Multiclone
___ Carbon Bed Adsorber	___ Packed Tower Scrubber	___ Single Cyclone
___ Carbon Drum(s)	_X_ Other Wet Scrubber	___ Cyclone Bank
___ Catalytic Incinerator	___ Condenser	___ Settling Chamber
___ Thermal Incinerator	___ Flare	___ Other (describe) _____________
___ Wet Plate Electrostatic Precipitator		___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
SO_2	100%	95%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Full Load Flow Rate = 2.6×10^6 acfm, Outlet temperature = 128 °F, Design Removal Efficiency = 95%

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of SO_2 emissions using CEMS

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number: ML2 SCR	**List all emission units associated with this control device.** Unit 2	
Manufacturer:	**Model number:** Custom	**Installation date:** 05/02/2007

Type of Air Pollution Control Device:

___ Baghouse/Fabric Filter ___ Venturi Scrubber ___ Multiclone

___ Carbon Bed Adsorber ___ Packed Tower Scrubber ___ Single Cyclone

___ Carbon Drum(s) ___ Other Wet Scrubber ___ Cyclone Bank

___ Catalytic Incinerator ___ Condenser ___ Settling Chamber

___ Thermal Incinerator ___ Flare _X_ Other (describe) Selective Catalytic Reduction

___ Wet Plate Electrostatic Precipitator ___ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
NO_x	100%	90%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).
NOx Control Efficiency = 90.0%, Design Temperature = 750 ºF, Maximum ammonia slip = 2 ppmvd at 3% O_2

Is this device subject to the CAM requirements of 40 C.F.R. 64? ___ Yes _X_ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.** Continuous Emissions Monitoring Used.

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Monitoring of NO_x emissions using CEMS

Attachment H

Compliance Assurance Monitoring (CAM) Forms

ATTACHMENT H - Compliance Assurance Monitoring (CAM) Plan Form

For definitions and information about the CAM rule, please refer to 40 CFR Part 64. Additional information (including guidance documents) may also be found at http://www.epa.gov/ttn/emc/cam.html

CAM APPLICABILITY DETERMINATION

1) Does the facility have a PSEU (Pollutant-Specific Emissions Unit considered separately with respect to **EACH** regulated air pollutant) that is subject to CAM (40 CFR Part 64), which must be addressed in this CAM plan submittal? To determine applicability, a PSEU must meet **all** of the following criteria (*If No, then the remainder of this form need not be completed*):

☒ YES ☐ NO

a. The PSEU is located at a major source that is required to obtain a Title V permit;

b. The PSEU is subject to an emission limitation or standard for the applicable regulated air pollutant that is NOT exempt;

LIST OF EXEMPT EMISSION LIMITATIONS OR STANDARDS:

- NSPS (40 CFR Part 60) or NESHAP (40 CFR Parts 61 and 63) proposed after 11/15/1990.
- Stratospheric Ozone Protection Requirements.
- Acid Rain Program Requirements.
- Emission Limitations or Standards for which a WVDEP Division of Air Quality Title V permit specifies a continuous compliance determination method, as defined in 40 CFR §64.1.
- An emission cap that meets the requirements specified in 40 CFR §70.4(b)(12).

c. The PSEU uses an add-on control device (as defined in 40 CFR §64.1) to achieve compliance with an emission limitation or standard;

d. The PSEU has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than the Title V Major Source Threshold Levels; AND

e. The PSEU is NOT an exempt backup utility power emissions unit that is municipally-owned.

BASIS OF CAM SUBMITTAL

2) Mark the appropriate box below as to why this CAM plan is being submitted as part of an application for a Title V permit:

☒ RENEWAL APPLICATION. **ALL** PSEUs for which a CAM plan has NOT yet been approved need to be addressed in this CAM plan submittal.

☐ INITIAL APPLICATION (submitted after 4/20/98). **ONLY** large PSEUs (i. e., PSEUs with potential post-control device emissions of an applicable regulated air pollutant that are equal to or greater than Major Source Threshold Levels) need to be addressed in this CAM plan submittal.

☐ SIGNIFICANT MODIFICATION TO LARGE PSEUs. **ONLY** large PSEUs being modified after 4/20/98 need to be addressed in this cam plan submittal. For large PSEUs with an approved CAM plan, Only address the appropriate monitoring requirements affected by the significant modification.

3) [a] BACKGROUND DATA AND INFORMATION					
Complete the following table for **all** PSEUs that need to be addressed in this CAM plan submittal. This section is to be used to provide background data and information for each PSEU In order to supplement the submittal requirements specified in 40 CFR §64.4. If additional space is needed, attach and label accordingly.					
PSEU DESIGNATION	DESCRIPTION	POLLUTANT	CONTROL DEVICE	[b] EMISSION LIMITATION or STANDARD	[c] MONITORING REQUIREMENT
Unit 1	Coal-Fired Steam Generator	PM	ESP	45CSR2-4.1.a	Monitor Duct Opacity Using COMS
Unit 2	Coal-Fired Steam Generator	PM	ESP	45CSR2-4.1.a	Monitor Duct Opacity Using COMS
<u>EXAMPLE</u> Boiler No. 1	Wood-Fired Boiler	PM	Multiclone	45CSR§2-4.1.c.; 9.0 lb/hr	Monitor pressure drop across multiclone: Weekly inspection of multiclone

[a] If a control device is common to more than one PSEU, one monitoring plan may be submitted for the control device with the affected PSEUs identified and any conditions that must be maintained or monitored in accordance with 40 CFR §64.3(a). If a single PSEU is controlled by more than one control device similar in design and operation, one monitoring plan for the applicable control devices may be submitted with the applicable control devices identified and any conditions that must be maintained or monitored in accordance with 40 CFR §64.3(a).

[b] Indicate the emission limitation or standard for any applicable requirement that constitutes an emission limitation, emission standard, or standard of performance (as defined in 40 CFR §64.1).

[c] Indicate the monitoring requirements for the PSEU that are required by an applicable regulation or permit condition.

CAM MONITORING APPROACH CRITERIA			
Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide monitoring data and information for EACH indicator selected for EACH PSEU in order to meet the monitoring design criteria specified in 40 CFR §64.3 and §64.4. if more than two indicators are being selected for a PSEU or if additional space is needed, attach and label accordingly with the appropriate PSEU designation, pollutant, and indicator numbers.			
4a) PSEU Designation: **Unit 1**	**4b) Pollutant:** **PM**	**4c) [a] Indicator No. 1:** Opacity	**4d) [a] Indicator No. 2:** **Opacity**
5a) GENERAL CRITERIA Describe the MONITORING APPROACH used to measure the indicators:		Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.	Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.
[b] Establish the appropriate INDICATOR RANGE or the procedures for establishing the indicator range which provides a reasonable assurance of compliance:		Opacity data has been collected during Method 5 particulate emission testing. The plan will incorporate existing test data along with CAM stack testing to verify a conservative indicator range. The proposed upper threshold value of the indicator range is a 3-hour block average opacity value greater than 10% Opacity	Excess short duration opacity increases occurring during any calendar quarter are not to exceed 5% of the total operating time.
5b) PERFORMANCE CRITERIA Provide the SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, such as detector location, installation specifications, and minimum acceptable accuracy:		The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.	The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.
[c] For new or modified monitoring equipment, provide VERIFICATION PROCEDURES, including manufacturer's recommendations, TO CONFIRM THE OPERATIONAL STATUS of the monitoring:		N/A	N/A
Provide QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES that are adequate to ensure the continuing validity of the data, (i.e., daily calibrations, visual inspections, routine maintenance, RATA, etc.):		QA/QC is performed in accordance with 40 CFR 75.	QA/QC is performed in accordance with 40 CFR 75.
[d] Provide the MONITORING FREQUENCY:		Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)	Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)
Provide the DATA COLLECTION PROCEDURES that will be used:		Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.	Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.
Provide the DATA AVERAGING PERIOD for the purpose of determining whether an excursion or exceedance has occurred:		The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase).	The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase) and the total operating time of the units.

[a] Describe all indicators to be monitored which satisfies 40 CFR §64.3(a). Indicators of emission control performance for the control device and associated capture system may include measured or predicted emissions (including visible emissions or opacity), process and control device operating parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities.

[b] Indicator Ranges may be based on a single maximum or minimum value or at multiple levels that are relevant to distinctly different operating conditions, expressed as a function of process variables, expressed as maintaining the applicable indicator in a particular operational status or designated condition, or established as interdependent between more than one indicator. For CEMS, COMS, or PEMS, include the most recent certification test for the monitor.

[c] The verification for operational status should include procedures for installation, calibration, and operation of the monitoring equipment, conducted in accordance with the manufacturer's recommendations, necessary to confirm the monitoring equipment is operational prior to the commencement of the required monitoring.

[d] Emission units with post-control PTE ≥ 100 percent of the amount classifying the source as a major source (i.e., Large PSEU) must collect four or more values per hour to be averaged. A reduced data collection frequency may be approved in limited circumstances. Other emission units must collect data at least once per 24 hour period.

CAM MONITORING APPROACH CRITERIA

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide monitoring data and information for EACH indicator selected for EACH PSEU in order to meet the monitoring design criteria specified in 40 CFR §64.3 and §64.4. if more than two indicators are being selected for a PSEU or if additional space is needed, attach and label accordingly with the appropriate PSEU designation, pollutant, and indicator numbers.

4a) PSEU Designation: Unit 2	**4b) Pollutant:** PM	**4c) [a] Indicator No. 1:** Opacity	**4d) [a] Indicator No. 2:** Opacity
5a) GENERAL CRITERIA Describe the MONITORING APPROACH used to measure the indicators:		Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.	Opacity data is measured and recorded by a certified continuous opacity monitoring system (COMS). The 6-minute average data is recorded and will be used to calculate block 3-hour average opacity values.
[b] Establish the appropriate INDICATOR RANGE or the procedures for establishing the indicator range which provides a reasonable assurance of compliance:		Opacity data has been collected during Method 5 particulate emission testing. The plan will incorporate existing test data along with CAM stack testing to verify a conservative indicator range. The proposed upper threshold value of the indicator range is a 3-hour block average opacity value greater than 10% Opacity	Excess short duration opacity increases occurring during any calendar quarter are not to exceed 5% of the total operating time.
5b) PERFORMANCE CRITERIA Provide the SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, such as detector location, installation specifications, and minimum acceptable accuracy:		The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.	The COMs is located in the duct downstream of the ESP in accordance with 40 CFR 60.13(i)(1); the COMs is installed, maintained and provides data accuracy in accordance with 40 CFR 75.
[c] For new or modified monitoring equipment, provide VERIFICATION PROCEDURES, including manufacturer's recommendations, TO CONFIRM THE OPERATIONAL STATUS of the monitoring:		N/A	N/A
Provide QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES that are adequate to ensure the continuing validity of the data, (i.e., daily calibrations, visual inspections, routine maintenance, RATA, etc.):		QA/QC is performed in accordance with 40 CFR 75.	QA/QC is performed in accordance with 40 CFR 75.
[d] Provide the MONITORING FREQUENCY:		Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)	Opacity is measured continuously except for periods of monitor malfunction or downtime (e.g. calibration, repairs, etc.)
Provide the DATA COLLECTION PROCEDURES that will be used:		Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.	Opacity data will be collected and stored in a Data Acquisition System (DAS) on a block 3-hour average basis.
Provide the DATA AVERAGING PERIOD for the purpose of determining whether an excursion or exceedance has occurred:		The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase).	The opacity values used to compare with the upper threshold value of the indicator range is the block 3-hour average opacity (short duration opacity increase) and the total operating time of the units.

[a] Describe all indicators to be monitored which satisfies 40 CFR §64.3(a). Indicators of emission control performance for the control device and associated capture system may include measured or predicted emissions (including visible emissions or opacity), process and control device operating parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities.

[b] Indicator Ranges may be based on a single maximum or minimum value or at multiple levels that are relevant to distinctly different operating conditions, expressed as a function of process variables, expressed as maintaining the applicable indicator in a particular operational status or designated condition, or established as interdependent between more than one indicator. For CEMS, COMS, or PEMS, include the most recent certification test for the monitor.

[c] The verification for operational status should include procedures for installation, calibration, and operation of the monitoring equipment, conducted in accordance with the manufacturer's recommendations, necessary to confirm the monitoring equipment is operational prior to the commencement of the required monitoring.

[d] Emission units with post-control PTE ≥ 100 percent of the amount classifying the source as a major source (i.e., Large PSEU) must collect four or more values per hour to be averaged. A reduced data collection frequency may be approved in limited circumstances. Other emission units must collect data at least once per 24 hour period.

RATIONALE AND JUSTIFICATION	
Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide rationale and justification for the selection of EACH indicator and monitoring approach and EACH indicator range in order to meet the submittal requirements specified in 40 CFR §64.4.	
6a) PSEU Designation: Unit 1	6b) Regulated Air Pollutant: PM

7) **INDICATORS AND THE MONITORING APPROACH**: Provide the rationale and justification for the selection of the indicators and the monitoring approach used to measure the indicators. Also provide any data supporting the rationale and justification. Explain the reasons for any differences between the verification of operational status or the quality assurance and control practices proposed, and the manufacturer's recommendations. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

Wheeling Power believes that the continuous opacity monitoring system (COMS) data is the most appropriate and readily available indicator for continuously evaluating the performance and operations of the electrostatic precipitator and thereby assessing compliance with the applicable particulate emission rate limitation between periodic 40 CFR Part 60, Method 5 compliance testing. Monitoring of other ESP operating parameters such as TR set voltage and current levels may be beneficial in evaluating ESP performance trends on a short term basis as well, however, these are not continuous nor are they direct indicators of conditions in the stack prior to release of the flue gas. For these reasons, a specific corrective action plan has been developed based upon opacity monitoring. This corrective action plan will be implemented at any time there is a short duration or a sustained duration increase in opacity above the upper threshold value of the indicator range.

Monitoring: The permittee shall monitor and maintain 6-minute opacity averages measured by a continuous opacity monitoring system, operated and maintained pursuant to 40 C.F.R. Part 75, including the minimum data requirements, in order to determine 3-hour block average opacity values. The 6-minute opacity averages shall be used to calculate 3-hour block average opacity values. The COM QA/QC procedures shall be equivalent to the applicable requirements of 40 C.F.R. Part 75. Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, but not limited to, calibration checks and required zero and span adjustments), the opacity shall be continuously monitored (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs and QA/QC activities shall not be used for purposes of 40 C.F.R. Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement. Data availability shall be at least of 50% of the operating time in the 3-hour block to satisfy the data requirements to calculate the 3-hour average opacity. The number of invalid 3-hour blocks shall not exceed 15% of the total 3-hour blocks during unit operation for a quarterly reporting period.

Recordkeeping: Records of the block 3-hour COMS opacity averages and corrective actions taken during excursions of the CAM plan indicator range shall be maintained on site and shall be made available to the Director or his duly authorized representative upon request. COMS performance data will be maintained in accordance with 40 C.F.R. Part 75 recordkeeping requirements. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 C.F.R. §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 C.F.R. Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

Reporting: The permittee shall submit semiannual monitoring reports to the DAQ. A report for monitoring under 40 C.F.R. 64 shall include, at a minimum, the following information: (a) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions and the corrective actions taken; (b) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks); and (c) A description of the actions taken to implement a quality improvement plan (QIP) during the reporting period as specified in 40 C.F.R. §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

For purposes of this corrective action plan:
A **short duration increase in opacity** is defined as an increase in opacity that persists for at least a block three-hour period (30 consecutive 6-minute periods), and which measure greater than the upper threshold value of the indicator range.
A **sustained increase in opacity (or an excursion)** is defined as an increase in opacity that persists for two consecutive 3-hour block periods (two consecutive short duration opacity increase periods), and which measure greater than the upper threshold value of the indicator range.

This plan outlines specific corrective action procedures to be implemented by plant personnel for the following scenarios:

Case A: Upon alarm of a Short duration increase in opacity.
Case B: Upon alarm of a sustained increase in opacity.

These corrective action procedures do not apply to opacity increases that occur during exempt periods. Assignment of personnel to carry out each step of this plan will be the sole responsibility of Plant Management and may change based upon specific conditions.

Case A: (Short duration increase in opacity.)
Plant personnel will continue to observe the COMS data and at the same time initiate a review of other available information (such as: TR set status, voltage, current, operating parameters, etc.) in order to validate and/or identify the cause of the opacity increase.

1. If the opacity does not return to and remain at normal operating levels within (within 180 minutes), further corrective action may become necessary.
1. If the cause of the opacity increase is not already known, unit-operating data will be collected for the purpose of determining the cause of the opacity increase.
1. If the opacity increase occurs after normal working hours, on weekends, or holidays; the unit-operations data may be collected the following working day.
1. Once the cause of the opacity increase is determined, plant personnel will take necessary steps to mitigate the unit operating condition or equipment failure that is found to be causing the short duration opacity increase.

B. Case B: (Sustained increase in opacity.)

1. Upon detecting an excursion or exceedance, the permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.
2. If the opacity does not return and remain at normal operating levels within a short duration (within 180 minutes), and the cause of the opacity increase is not already known, further analysis of the unit, and auxiliary operating data will be analyzed and recorded for the purpose of determining the cause of the opacity increase.
3. If the opacity increase occurs after normal working hours, on weekends, or holidays, off-shift personnel may be required to determine the cause of the opacity increase and initiate appropriate corrective actions.
4. Plant personnel will initiate the following corrective actions as necessary to reduce stack opacity to normal operating levels:
    a. Any individual TR sets that are out-of-service or not operating at normal power levels shall be repaired and/or adjusted as appropriate.
    b. ESP rapping procedures may be initiated and/or adjusted as necessary.
    c. Flue gas conditioning systems will be placed in service or adjusted as necessary.
    d. Depending on the specific events found to be the cause of the opacity increase, other corrective actions will be implemented as necessary to reduce the opacity to normal operating levels.

If five (5) percent or greater of the block three (3) hour average COMS opacity values indicate excursions of the 10% opacity threshold during a calendar quarter, the permittee shall develop and implement a QIP. The Director may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to permit condition 3.3.1.

If the opacity level continues to exceed the upper threshold value of the indicator range Opacity after the corrective actions as outlined above for Case B are implemented, plant personnel will contact appropriate management staff to obtain necessary approvals to reduce load, or in extreme cases, commence a unit shutdown in order to remediate the cause of the opacity increase.

Based on the results of a determination of actions taken by the permittee, the Administrator or the Director may require the permittee to develop and implement a QIP. If a QIP is required, then it shall be developed, implemented, and modified as required according to 40 C.F.R. §§ 64.8(b) through (e).

8) **INDICATOR RANGES**: Provide the rationale and justification for the selection of the indicator ranges. The rationale and justification shall indicate how **EACH** indicator range was selected by either a COMPLIANCE OR PERFORMANCE TEST, a TEST PLAN AND SCHEDULE, or by ENGINEERING ASSESSMENTS. Depending on which method is being used for each indicator range, include the specific information required below for that specific indicator range. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- COMPLIANCE OR PERFORMANCE TEST (Indicator ranges determined from control device operating parameter data obtained during a compliance or performance test conducted under regulatory specified conditions or under conditions representative of maximum potential emissions under anticipated operating conditions. Such data may be supplemented by engineering assessments and manufacturer's recommendations). The rationale and justification shall INCLUDE a summary of the compliance or performance test results that were used to determine the indicator range, and documentation indicating that no changes have taken place that could result in a significant change in the control system performance or the selected indicator ranges since the compliance or performance test was conducted.

- TEST PLAN AND SCHEDULE (Indicator ranges will be determined from a proposed implementation plan and schedule for installing, testing, and performing any other appropriate activities prior to use of the monitoring). The rationale and justification shall INCLUDE the proposed implementation plan and schedule that will provide for use of the monitoring as expeditiously as practicable after approval of this CAM plan, except that in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval.

- ENGINEERING ASSESSMENTS (Indicator Ranges or the procedures for establishing indicator ranges are determined from engineering assessments and other data, such as manufacturers' design criteria and historical monitoring data, because factors specific to the type of monitoring, control device, or PSEU make compliance or performance testing unnecessary). The rationale and justification shall INCLUDE documentation demonstrating that compliance testing is not required to establish the indicator range.

RATIONALE AND JUSTIFICATION:

The indicator is based upon an opacity/mass relationship of the emissions unit at full load operation. It is anticipated that the 0.05 lb/mmBTU particulate emissions limit will not be exceeded when 3-hour block opacity values remain at or below 10% opacity. Accordingly, the Mitchell Plant can demonstrate a reasonable assurance of compliance with the particulate mass emission limit as long as the 3-hour block average stack (duct) opacity is maintained below the upper threshold value of 10%. opacity.

Wheeling Power Company is proposing that the opacity/mass relationship be verified using existing baseline mass particulate emission test results and additional full load "CAM Testing". Based on previous compliance or performance testing of the electrostatic precipitator using 40 CFR Part 60 methods, Wheeling Power Company believes that compliance with the upper threshold value of 10% opacity for the 3-hour block average periods will provide reasonable assurance of compliance with the particulate emission standard. The 10% threshold was chosen for two reasons: first, the historic particulate emission test data that has been collected over the past few years shows this source to be in compliance with the 0.05 lb/mmBTU particulate limit by a good margin when stack opacity is less than 10% and second, we presume that DAQ established the 10% 45 CSR 2 opacity SIP limit at a level that DAQ believes sources will likely be in compliance with the mass SIP limit to provide a conservative reasonable assurance of compliance with the mass emission limit. The 3-hour block averaging time period was chosen to provide adequate time to make operational corrections to comply with the particulate mass emission standard.

Historic baseline test data collected in the past recent years and submitted to WV DEP is summarized below:

Test Date	Measured Emission Rate	Average Opacity
8/21/2000	0.0180 lb/mmBtu	7.0
8/5/2003	0.0147 lb/mmBtu	3.3
7/14/2006	0.0134 lb/mmBtu	3.2
4/7/2009	0.0195 lb/mmBtu	5.1
1/24/2012	0.0337 lb/mmBtu	3.7
12/14/2012	0.0037 lb/mmBtu	6.1
3/18/2014	0.0033 lb/mmBtu	7.6
3/3/2016	0.0030 lb/mmBtu	3.9
12/12/2018	0.0026 lb/mmBtu	6.2
6/17/2021	0.0040 lb/mmBtu	6.8

No changes have been made that would significantly impact ESP performance. Data collected during future periodic 45CSR2 mass emissions tests will be used to supplement the existing data set in order to verify the continuing appropriateness of the 10% indicator range value.

While the above compliance test data has been used as baseline confirmation of mass emission compliance at full load, additional full load testing was also conducted to supplement the data set with data points collected while operating at or near the 10% opacity threshold. These points were established by "de-tuning" the electrostatic precipitator (making adjustments to operating parameters of the precipitator) and/or making other operational adjustments to the unit to increase the particulate mass loading and opacity downstream of the precipitator. The data set used to establish the opacity/mass relationship and the indicator verification consist of the particulate mass emissions compliance test data and the data collected during the CAM testing program. The CAM testing at elevated opacity levels was performed for one 2-hour test run (as opposed to a full 6-hour time period typical of a compliance test). Limiting the data collection to 2-hours minimized the environmental impacts of operating the particulate control equipment under less than normal operating conditions. Nevertheless, it was understood that more than one run under specific unit operating conditions may be necessary.

RATIONALE AND JUSTIFICATION

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide rationale and justification for the selection of EACH indicator and monitoring approach and EACH indicator range in order to meet the submittal requirements specified in 40 CFR §64.4.

6a) PSEU Designation:	6b) Regulated Air Pollutant:
Unit 2	PM

7) **INDICATORS AND THE MONITORING APPROACH**: Provide the rationale and justification for the selection of the indicators and the monitoring approach used to measure the indicators. Also provide any data supporting the rationale and justification. Explain the reasons for any differences between the verification of operational status or the quality assurance and control practices proposed, and the manufacturer's recommendations. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

Wheeling Power believes that the continuous opacity monitoring system (COMS) data is the most appropriate and readily available indicator for continuously evaluating the performance and operations of the electrostatic precipitator and thereby assessing compliance with the applicable particulate emission rate limitation between periodic 40 CFR Part 60, Method 5 compliance testing. Monitoring of other ESP operating parameters such as TR set voltage and current levels may be beneficial in evaluating ESP performance trends on a short term basis as well, however, these are not continuous nor are they direct indicators of conditions in the stack prior to release of the flue gas. For these reasons, a specific corrective action plan has been developed based upon opacity monitoring. This corrective action plan will be implemented at any time there is a short duration or a sustained duration increase in opacity above the upper threshold value of the indicator range.

Monitoring: The permittee shall monitor and maintain 6-minute opacity averages measured by a continuous opacity monitoring system, operated and maintained pursuant to 40 C.F.R. Part 75, including the minimum data requirements, in order to determine 3-hour block average opacity values. The 6-minute opacity averages shall be used to calculate 3-hour block average opacity values. The COM QA/QC procedures shall be equivalent to the applicable requirements of 40 C.F.R. Part 75. Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, but not limited to, calibration checks and required zero and span adjustments), the opacity shall be continuously monitored (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs and QA/QC activities shall not be used for purposes of 40 C.F.R. Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement. Data availability shall be at least of 50% of the operating time in the 3-hour block to satisfy the data requirements to calculate the 3-hour average opacity. The number of invalid 3-hour blocks shall not exceed 15% of the total 3-hour blocks during unit operation for a quarterly reporting period.

Recordkeeping: Records of the block 3-hour COMS opacity averages and corrective actions taken during excursions of the CAM plan indicator range shall be maintained on site and shall be made available to the Director or his duly authorized representative upon request. COMS performance data will be maintained in accordance with 40 C.F.R. Part 75 recordkeeping requirements. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 C.F.R. §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 C.F.R. Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

Reporting: The permittee shall submit semiannual monitoring reports to the DAQ. A report for monitoring under 40 C.F.R. 64 shall include, at a minimum, the following information: (a) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions and the corrective actions taken; (b) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks); and (c) A description of the actions taken to implement a quality improvement plan (QIP) during the reporting period as specified in 40 C.F.R. §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

For purposes of this corrective action plan:
A **short duration increase in opacity** is defined as an increase in opacity that persists for at least a block three-hour period (30 consecutive 6-minute periods), and which measure greater than the upper threshold value of the indicator range.
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These corrective action procedures do not apply to opacity increases that occur during exempt periods. Assignment of personnel to carry out each step of this plan will be the sole responsibility of Plant Management and may change based upon specific conditions.

Case A: (Short duration increase in opacity.)
Plant personnel will continue to observe the COMS data and at the same time initiate a review of other available information (such as: TR set status, voltage, current, operating parameters, etc.) in order to validate and/or identify the cause of the opacity increase.

1. If the opacity does not return to and remain at normal operating levels within (within 180 minutes), further corrective action may become necessary.
3. If the cause of the opacity increase is not already known, unit-operating data will be collected for the purpose of determining the cause of the opacity increase.
3. If the opacity increase occurs after normal working hours, on weekends, or holidays; the unit-operations data may be collected the following working day.
4. Once the cause of the opacity increase is determined, plant personnel will take necessary steps to mitigate the unit operating condition or equipment failure that is found to be causing the short duration opacity increase.

B. Case B: (Sustained increase in opacity.)

1. Upon detecting an excursion or exceedance, the permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.
2. If the opacity does not return and remain at normal operating levels within a short duration (within 180 minutes), and the cause of the opacity increase is not already known, further analysis of the unit, and auxiliary operating data will be analyzed and recorded for the purpose of determining the cause of the opacity increase.
3. If the opacity increase occurs after normal working hours, on weekends, or holidays, off-shift personnel may be required to determine the cause of the opacity increase and initiate appropriate corrective actions.
4. Plant personnel will initiate the following corrective actions as necessary to reduce stack opacity to normal operating levels:
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    b. ESP rapping procedures may be initiated and/or adjusted as necessary.
    c. Flue gas conditioning systems will be placed in service or adjusted as necessary.
    d. Depending on the specific events found to be the cause of the opacity increase, other corrective actions will be implemented as necessary to reduce the opacity to normal operating levels.

If five (5) percent or greater of the block three (3) hour average COMS opacity values indicate excursions of the 10% opacity threshold during a calendar quarter, the permittee shall develop and implement a QIP. The Director may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to permit condition 3.3.1.

If the opacity level continues to exceed the upper threshold value of the indicator range Opacity after the corrective actions as outlined above for Case B are implemented, plant personnel will contact appropriate management staff to obtain necessary approvals to reduce load, or in extreme cases, commence a unit shutdown in order to remediate the cause of the opacity increase.

Based on the results of a determination of actions taken by the permittee, the Administrator or the Director may require the permittee to develop and implement a QIP. If a QIP is required, then it shall be developed, implemented, and modified as required according to 40 C.F.R. §§ 64.8(b) through (e).

8) **INDICATOR RANGES**: Provide the rationale and justification for the selection of the indicator ranges. The rationale and justification shall indicate how **EACH** indicator range was selected by either a COMPLIANCE OR PERFORMANCE TEST, a TEST PLAN AND SCHEDULE, or by ENGINEERING ASSESSMENTS. Depending on which method is being used for each indicator range, include the specific information required below for that specific indicator range. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- COMPLIANCE OR PERFORMANCE TEST (Indicator ranges determined from control device operating parameter data obtained during a compliance or performance test conducted under regulatory specified conditions or under conditions representative of maximum potential emissions under anticipated operating conditions. Such data may be supplemented by engineering assessments and manufacturer's recommendations). The rationale and justification shall INCLUDE a summary of the compliance or performance test results that were used to determine the indicator range, and documentation indicating that no changes have taken place that could result in a significant change in the control system performance or the selected indicator ranges since the compliance or performance test was conducted.

- TEST PLAN AND SCHEDULE (Indicator ranges will be determined from a proposed implementation plan and schedule for installing, testing, and performing any other appropriate activities prior to use of the monitoring). The rationale and justification shall INCLUDE the proposed implementation plan and schedule that will provide for use of the monitoring as expeditiously as practicable after approval of this CAM plan, except that in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval.

- ENGINEERING ASSESSMENTS (Indicator Ranges or the procedures for establishing indicator ranges are determined from engineering assessments and other data, such as manufacturers' design criteria and historical monitoring data, because factors specific to the type of monitoring, control device, or PSEU make compliance or performance testing unnecessary). The rationale and justification shall INCLUDE documentation demonstrating that compliance testing is not required to establish the indicator range.

RATIONALE AND JUSTIFICATION:

The indicator is based upon an opacity/mass relationship of the emissions unit at full load operation. It is anticipated that the 0.05 lb/mmBTU particulate emissions limit will not be exceeded when 3-hour block opacity values remain at or below 10% opacity. Accordingly, the Mitchell Plant can demonstrate a reasonable assurance of compliance with the particulate mass emission limit as long as the 3-hour block average stack (duct) opacity is maintained below the upper threshold value of 10%. opacity.

Wheeling Power Company is proposing that the opacity/mass relationship be verified using existing baseline mass particulate emission test results and additional full load "CAM Testing". Based on previous compliance or performance testing of the electrostatic precipitator using 40 CFR Part 60 methods, Wheeling Power Company believes that compliance with the upper threshold value of 10% opacity for the 3-hour block average periods will provide reasonable assurance of compliance with the particulate emission standard. The 10% threshold was chosen for two reasons: first, the historic particulate emission test data that has been collected over the past few years shows this source to be in compliance with the 0.05 lb/mmBTU particulate limit by a good margin when stack opacity is less than 10% and second, we presume that DAQ established the 10% 45 CSR 2 opacity SIP limit at a level that DAQ believes sources will likely be in compliance with the mass SIP limit to provide a conservative reasonable assurance of compliance with the mass emission limit. The 3-hour block averaging time period was chosen to provide adequate time to make operational corrections to comply with the particulate mass emission standard.

Historic baseline test data collected in the past recent years and submitted to WV DEP is summarized below:

Test Date	Measured Emission Rate	Average Opacity
8/21/2000	0.0180 lb/mmBtu	7.0
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7/14/2006	0.0134 lb/mmBtu	3.2
4/8/2009	0.0099 lb/mmBtu	5.9
1/26/2012	0.0421 lb/mmBtu	6.2
12/13/2012	0.0038 lb/mmBtu	6.1
3/20/2014	0.0035 lb/mmBtu	7.2
3/2/2016	0.0031 lb/mmBtu	5.9
12/13/2018	0.0045 lb/mmBtu	8.5
6/16/2021	0.0039 lb/mmBtu	8.7

No changes have been made that would significantly impact ESP performance. Data collected during future periodic 45CSR2 mass emissions tests will be used to supplement the existing data set in order to verify the continuing appropriateness of the 10% indicator range value.

While the above compliance test data has been used as baseline confirmation of mass emission compliance at full load, additional full load testing was also conducted to supplement the data set with data points collected while operating at or near the 10% opacity threshold. These points were established by "de-tuning" the electrostatic precipitator (making adjustments to operating parameters of the precipitator) and/or making other operational adjustments to the unit to increase the particulate mass loading and opacity downstream of the precipitator. The data set used to establish the opacity/mass relationship and the indicator verification consist of the particulate mass emissions compliance test data and the data collected during the CAM testing program. The CAM testing at elevated opacity levels was performed for one 2-hour test run (as opposed to a full 6-hour time period typical of a compliance test). Limiting the data collection to 2-hours minimized the environmental impacts of operating the particulate control equipment under less than normal operating conditions. Nevertheless, it was understood that more than one run under specific unit operating conditions may be necessary.

Attachment I
Existing Applicable Permits

West Virginia Department of Environmental Protection

Earl Ray Tomblin
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Class I Administrative Update Permit

R13-2608E

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:

AEP Generation Resources, Inc.
Mitchell Plant
051-00005

William F. Dunham
Deputy Director

Issued: May 12, 2014

This permit will supercede and replace Permit R13-2608D.

Facility Location:	State Route 2 Cresap/Moundsville, Marshall County, West Virginia
Mailing Address:	Mitchell Plant P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generating Plant
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Permit Type:	Administrative Update
Description of Change:	This update is to correctly codify the term of the limited use for Boiler Aux-1 in the terms as defined in the Subpart DDDDD of Part 63 of Chapter 40 and correctly define the compliance path for Aux-1 under Subpart Db of Part 60 in Chapter 40.

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	Design Capacity	Control Device
		1S - Limestone Material Handling		
BUN-1		Limestone Unloading Crane	1,000 TPH	None
RH-1		Limestone Unloading Hopper	60 Tons	WS/PE
VF-1		Limestone Unloading Feeder	750 TPH	FE
BC-1		Limestone Dock/Connecting Conveyor	750 TPH	PE
TH-1		Limestone Transfer House #1	750 TPH	FE
BC-2		Limestone Storage Pile Stacking Conveyor	750 TPH	PE
LSSP		Limestone Active/Long-Term Stockpile	41,300 Tons	None
		2S - Gypsum Material Handling		
BC-8		Vacuum Collecting Conveyor	200 TPH	PE
TH-3		Gypsum Transfer House #3	200 TPH	FE
BC-9		Connecting Conveyor	200 TPH	PE
TH-4		Gypsum Transfer House #4	200 TPH	FE
BC-10		Connecting Conveyor	200 TPH	PE
TH-5		Gypsum Transfer House #5	200 TPH	FE
BC-11		Connecting Conveyor	200 TPH	PE
TH-6		Gypsum Transfer House #6	200 TPH	FE
BC-12		Stacking Tripper Conveyor	200 TPH	PE
GSP		Gypsum Stockpile	15,600 Tons	FE
PSR-1		Traveling Portal Scraper Reclaimer	1,000 TPH	FE
BC-14		Reclaim Conveyor	1,000 TPH	PE
TH-7		Transfer House #7	1,000 TPH	FE
BC-13		Bypass Conveyor	200 TPH	PE
BC-15		Connecting Conveyor	1,000 TPH	PE
TH-1		Transfer House #1	1,000 TPH	FE
BC-16		Transfer Conveyor	1,000 TPH	PE
BL-1		Barge Loader	1,000 TPH	PE
BC-14		Reclaim Conveyor Extension	1,000 TPH	PE
TH-8		Transfer House #8	1,000 TPH	FE
BC-19		Transfer Conveyor	1,000 TPH	PE
TH-9		Transfer House #9	1,000 TPH	FE
BC-20		Transfer Conveyor	1,000 TPH	FE

Emission Unit ID	Emission Point ID	Emission Unit Description	Design Capacity	Control Device
TH-10		Transfer House #10	1,000 TPH	PE
BC-21		Transfer Conveyor to 21	1,000 TPH	FE
BUN-1		Clamshell Unloading Crane	1,000 TPH	
RH-4		Gypsum Unloading Hopper	30 tons	WSPE
RP-1		Gypsum Rotary Plow	750 TPH	FE
BC-17		Dock Connecting Conveyor	750 TPH	PE
TH-7		Transfer House #7	750 TPH	FE
BC-18		Bypass Conveyor	750 TPH	PE
TH-6		Transfer House #6	750 TPH	FE
3S		**Limestone Mineral Processing**		
VF-2		Limestone Reclaim Feeder 2	750 TPH	FE
VF-3		Limestone Reclaim Feeder 3	750 TPH	FE
BC-3		Limestone Tunnel Reclaim Conveyor	750 TPH	PE
FB-1		Emergency Limestone Reclaim Feeder/Breaker	750 TPH	None
TH-2		Limestone Transfer House 2	750 TPH	FE
BC-4		Limestone Silo A Feed Conveyor	750 TPH	PE
BC-5		Limestone Silo B Feed Conveyor	750 TPH	PE
BC-6		Limestone Silo C Feed Conveyor (future)	750 TPH	PE
LSB-1	6E	Limestone Silo A	900 tons	FF
LSB-2	7E	Limestone Silo B	900 tons	FF
LSB-3	8E	Limestone Silo C (future)	900 tons	FF
		Vibrating Bin Discharger (one per silo)	68.4 TPH	FE
LSWF-1 LSWF-2 LSWF-3		Limestone Weigh Feeder	68.4 TPH	FE
		Wet Ball Mill (one per silo)	68.4 TPH	FE
4S		**Dry Sorbent Material Handling**		
		Truck Unloading Connection (2)	25 TPH	FE
DSSB-1	10E	Dry Sorbent Storage Silo #1	500 Tons	FE/FF
DSSB-1	11E	Dry Sorbent Storage Silo #2	500 Tons	FE/FF
		Aeration Distribution Bins	4.6 TPH	FE
		De-aeration Bins	4.6 TPH	FE
		Rotary Feeder	4.6 TPH	FE
5S		**Coal Blending System**		

Emission Unit ID	Emission Point ID	Emission Unit Description	Design Capacity	Control Device
HTS-1		Transfer House #1	3,000 TPH	FE
HSC-1		Stacking Conveyor #1	3,000 TPH	PE
HTS-2A		Transfer House #2A	3,000 TPH	FE
HSC-2		Stacking Conveyor #2	3,000 TPH	PE
HTS-3		Transfer House #3	3,000 TPH	FE
HSC-3		Stacking Conveyor #3	3,000 TPH	PE
SH-1		Stacking Hopper SH-1 Transfer to SC-3 (receives coal from existing plant radial stacker R9)	3,000 TPH	FE
HSC-3 to High Sulfur Pile (CSA-2, existing)		Transfer from Stacking Conveyor HSC-3 to the High Sulfur Coal Pile located at existing North Yard Storage Area (CSA-2)	3,000 TPH	ST
HVF-1		Coal Reclaim Feeder 1	800 TPH	FE
HVF-2		Coal Reclaim Feeder 1	800 TPH	FE
HVF-3		Coal Reclaim Feeder 1	800 TPH	FE
HVF-4		Coal Reclaim Feeder 1	800 TPH	FE
HVF-1 through HVF-4 to HRC-1 (Transfer)_		Transfer from Vibrating Feeders HVF-1 through HVF-4 to Reclaim Conveyor HRC-1	1,600 TPH	FE
HRC-1		Coal Tunnel Reclaim Conveyor	1,600 TPH	PE
HTS-2B		Coal Transfer House #2B	1,600 TPH	FE
HRC-2		Reclaim Conveyor #2	1,600 TPH	PE
HTS-4		Coal Transfer House #4	1,600 TPH	FE
HRC-3		Reclaim Conveyor #3	1,600 TPH	PE
HTS-5		Coal Transfer House #5	1,600 TPH	FE
SB-1		Surge Bin #1	80 Tons	FE
HBF-1A		Belt Feeder 1A	800 TPH	PE
HBF-1B		Belt Feeder 1B	800 TPH	PE
HBF-1A/1B to BF-4E/4W (Transfer)		Transfer from Belt Feeders HBF-1A and HBF-1B to Existing Coal Conveyors 4E and 4W	1,600 TPH	FE
6S. 7S		**Emergency Quench Water System**		
6S	15E	Diesel Fired Engine for Quench Pump #1	60 Bhp	None
7S	16E	Diesel Fired Engine for Quench Pump #2	60 Bhp	None
9S		**Magnesium Hydroxide Material Handling System**		
MHM-1		Magnesium Hydroxide Mix Tank	1,000 Gallons	

Emission Unit ID	Emission Point ID	Emission Unit Description	Design Capacity	Control Device
MHM-2		Magnesium Hydroxide Mix Tank	1,000 Gallons	
11S		**Wastewater Treatment System Material Handling**		
		Truck Unloading Connection (2)	25 TPH	FE
		Lime Storage Silo #1	100 TPH	FE//FF
		Lime Storage Silo #2	100 TPH	FE//FF
		Wastewater Treatment Cake Stockpile	3,600 Tons	BE
FB-2		Filter Cake Feeder/Breaker	600 TPH	PE
BC-22		Transfer Conveyor 22	600 TPH	PE
TH-12		Transfer House #12	600 TPH	PE
		Fly Ash Handling System		
ME-1A	EP-1	Unit 1 Mechanical Exhauster		FF/Separator
ME-1B	EP-2	Unit 1 Mechanical Exhauster		FF/Separator
ME-1C	EP-3	Unit 1 Mechanical Exhauster		FF/Separator
ME-2A	EP-4	Unit 2 Mechanical Exhauster		FF/Separator
ME-2B	EP-5	Unit 2 Mechanical Exhauster		FF/Separator
ME-2C	EP-6	Unit 2 Mechanical Exhauster		FF/Separator
FAS-A	EP-7	Fly Ash Silo A	2,160 tons	FF Bin Vent
FAS-B	EP-8	Fly Ash Silo B	2,160 tons	FF Bin Vent
FAS-B	EP-8	Fly Ash Silo B	2,160 tons	FF Bin Vent
WFA-AA	F-1	Conditioned fly ash transfer from Silo A to Truck	360 TPH	MC
WFA-BA	F-2	Conditioned fly ash transfer from Silo B to Truck	360 TPH	MC
WFA-CA	F-3	Conditioned fly ash transfer from Silo C to Truck	360 TPH	MC
WFA-BA	F-4	Conditioned fly ash transfer from Silo A to Truck	360 TPH	MC
WFA-BB	F-5	Conditioned fly ash transfer from Silo B to Truck	360 TPH	MC
WFA-CB	F-6	Conditioned fly ash transfer from Silo C to Truck	360 TPH	MC
TC-A	EP-10	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
TC-B	EP-11	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
TC-C	EP-12	Dry Ash Transfer from Silo A to Truck	360 TPH	TC
		Auxiliary Boiler		
Aux-1	Aux-ML-1	Auxiliary Boiler using Flue Gas Recirculation with Low NO_x Burners	663 MMBtu/hr	None
You can type whatever you want here :o)				

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

2.3.3. 45CSR19 – *Requirements for Pre-Construction Review, Determination of Emission Offsets for Proposed New or Modified Stationary Sources of Air Pollution and Emission Trading for Intrasource Pollutants.*

2.4. Term and Renewal

2.4.1. This permit supersedes and replaces previously issued Permit R13-2608D. 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 R13-2608, R13-2608A, R13-2608B, R13-2608C, R13-2608D, R13-2608E, 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.]

3.2. 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

4.1. Limitations and Standards

4.1.1. Limestone transferred across belt conveyor BC-1 to Transfer House #1 [TH-1] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.

4.1.2 Limestone transferred across belt conveyor BC-3 to Transfer House #2 [TH-2] shall be limited to a maximum transfer rate of 750 tons per hour and 1,100,000 tons per year.

4.1.3. Gypsum transferred across belt conveyor BC-9 to Transfer House #4 [TH-4] shall be limited to a maximum transfer rate of 200 tons per hour and 1,700,000 tons per year.

4.1.4. Gypsum and wastewater treatment system cake transferred across belt conveyor BC-14 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,912,000 tons per year.

4.1.5. Gypsum transferred across belt conveyor BC-17 to Transfer House #7 [TH-7] shall be limited to a maximum transfer rate of 750 tons per hour and 1,200,000 tons per year.

4.1.6. Gypsum transferred across belt conveyor BC-19 to Transfer House #9 [TH-9] shall be limited to a maximum transfer rate of 1,000 tons per hour and 1,700,000 tons per year.

4.1.7. Coal transferred across belt conveyor HSC-1 shall be limited to a maximum transfer rate of 3,000 tons per hour and 5,732,544 tons per year.

4.1.8. Dry Sorbent (Trona or Hydrated Lime) for SO_3 mitigation shall be delivered to the facility at a maximum annual rate of 81,000 tons per year.

4.1.9. Liquid magnesium hydroxide shall be delivered to the facility at a maximum annual rate of 6,600,000 gallons per year.

4.1.10. Hydrated lime for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 3,200 tons per year.

4.1.11. Ferric Chloride for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 110,000 gallons per year.

4.1.12. Acid (hydrochloric or sulfuric) for the FGD wastewater treatment system shall be delivered to the facility at a maximum annual rate of 170,000 gallons per year.

4.1.13. Polymer and organosulfide for the FGD wastewater treatment facility shall be delivered to the facility at a maximum annual rate of 13,500 gallons per year.

4.1.14. The diesel-fired engines [6S and 7S] used to power the emergency quench water system shall be limited to a total maximum combined annual operating schedule of 200 hours per year.

4.1.15. Compliance with all annual operating limits shall be determined using a twelve month rolling total. A twelve month rolling total shall mean the sum of the quantified operating data at any given time during the previous twelve (12) consecutive calendar months.

4.1.16. The permittee shall maintain a water truck on site and in good operating condition, and shall utilize same to apply water as often as is necessary in order to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads and other work areas where mobile equipment is used. The spraybar shall be equipped with spray nozzles, of sufficient size and number, so as to provide adequate coverage to the area being treated.

The pump delivering the water shall be of sufficient size and capacity so as to be capable of delivering to the spray nozzle(s) an adequate quantity of water and at a sufficient pressure, so as to assure that the treatment process will minimize the atmospheric entrainment of fugitive particulate emissions generated from the haulroads and work areas where mobile equipment is used.

4.1.17. Additionally, at least three times per year the permittee shall apply a mixture of water and an environmentally acceptable dust control additive hereafter referred to as solution to all unpaved haul roads. The solution shall have a concentration of dust control additive sufficient to minimize the atmospheric entrainment of fugitive particulate emissions that may be generated from haulroads.

4.1.18. The permittee shall not cause, suffer, allow or permit any source of fugitive particulate matter to operate that is not equipped with a fugitive particulate matter control system. This system shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter.

4.1.19. The installation and operation of the proposed Limestone Processing equipment [3S] shall be applicable to the limits and requirements set forth by 40CFR60 - Subpart OOO, "Standards of performance for non-metallic mineral processing plants."

a. The material transfers across the conveyors within the enclosed transfer stations and ball mill within the processing building will be limited to the opacity emissions from the building or building vents. The buildings will be limited to emissions of no visible opacity per 40CFR60.672(e)(1), and the vents from the buildings will be limited to an opacity of 7% and particulate emissions of 0.022 grains per dry standard cubic foot, per 40CFR60.672(e)(2).

b. The emissions from the baghouse on each of the limestone day bins will be limited to 7% opacity per 40CFR60.672(f).

c. All material transfer points outside of the buildings will be limited to a maximum 10% opacity per 40CFR60.672(b).

d. In order to comply with the emission and opacity limitations of this Subpart, the permittee shall employ dust suppression methods to minimize particulate emissions from the limestone processing equipment. In order to demonstrate compliance, in accordance to the requirements of the regulation, the applicant shall conduct performance testing and monitoring activities as set forth by this Subpart.

4.1.20. The maximum amount of fly ash handled by the fly ash handling system shall not exceed 800,000 tons per year on a dry (1% moisture) basis (i.e 980,000 tons per year at 20% moisture). Compliance with the throughput limit shall be determined using a rolling yearly total. A rolling yearly total shall mean the sum of the fly ash transferred for the previous twelve (12) consecutive calendar months.

4.1.21. PM emissions from Mechanical Exhausters ME-1A, ME-1B and ME-1C shall not exceed 0.16 lb/hr and 0.69 tpy individually nor 0.32 lb/hr and 1.38 tons per year combined.

4.1.22. PM emissions from Mechanical Exhausters ME-2A, ME-2B and ME-2C shall not exceed 0.15 lb/hr and 0.65 tpy individually nor 0.30 lb/hr and 1.30 tons per year combined.

4.1.23. PM emissions from Bin Vent Filters BVF-A, BVF-B and BVF-C shall not exceed 0.75 lb/hr nor 3.25 tpy combined.

4.1.24. PM emissions from the transfer of conditioned fly ash from the silos to trucks (WFA-AA, WFA-AB, WFA-BA, WFA-BB, WFA-CA, and WFA-CB) shall not exceed 0.07 pounds per hour nor 0.09 tons per year combined.

4.1.25. **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. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.1. and 4.1.2. of this permit, the permittee shall monitor the hourly and annual limestone transfer rates across belt conveyor BC-1 to Transfer House #1 [TH-1] and across belt conveyor BC-3 to Transfer House #2 [TH-2].

4.2.2. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.3., 4.1.4., 4.1.5. and 4.1.6. of this permit, the permittee shall monitor the hourly and annual gypsum and wastewater treatment cake transfer rates across belt conveyors BC-9 to Transfer House #4 [TH-4], BC-14 to Transfer House #7 [TH-7], BC-17 to the Transfer House #7 Extension, and BC-19 to Transfer House #9 [TH-9].

4.2.3. For the purpose of determining compliance with the material transfer limits set forth by Section 4.1.7. of this permit, the permittee shall monitor the hourly and annual coal transfer rates across belt conveyor HSC-1 to Transfer Station #2A.

4.2.4. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the SO_3 mitigation system, as set forth by Section 4.1.8. and 4.1.9. of this permit, the permittee shall monitor the on-site delivery of dry sorbent (including trona and hydrated lime) and liquid magnesium hydroxide.

4.2.5. For the purpose of determining compliance with the limits associated with the delivery of raw materials for the FGD wastewater treatment system, as set forth by Sections 4.1.10. through 4.1.13. of this permit, the permittee shall monitor the on-site delivery of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide.

4.2.6. For the purpose of determining compliance with the operating limits set forth by Section 4.1.14. of this permit, the permittee shall monitor the operating schedule of the diesel-fired engine [6S and 7S] used to power the emergency quench water system.

4.2.7. For the purpose of determining compliance with the limits associated with disposal of dry fly ash, as set forth by Section 4.1.20 of this permit, the permittee shall monitor and record the amount of dry fly ash disposed of.

4.2.8. For the purpose of determining compliance with the operating limits set forth by Section 4.1.17. of this permit, the permittee shall monitor and record the date that chemical solution is applied to the haulroads along with the amount and concentration of the solution applied.

4.3. Testing Requirements

4.3.1. For the purpose of determining compliance with the performance testing requirements of 40 C.F.R. Part 60, Subpart OOO, as set forth by Section 4.1.19. of this permit, the permittee shall conduct compliance testing of the permitted facility within 180 days of the equipment start-up. These tests will be used to determine the particulate matter emissions generated from the open transfer points and processing operations. The testing methods to be employed are as follows:

Pollutant	USEPA Test Method*
Determination of the Opacity of Emissions	9

* Per 40CFR60, Appendix A

The permittee shall submit to the Director of the DAQ a test protocol detailing the proposed test methods, date, and time testing is to take place, testing locations, and any other relevant information. The test protocol must be received by the Director no less than thirty (30) days prior to the date the testing is to take place. The Director shall be notified at least fifteen (15) days in advance of the actual dates and times during which the tests will be conducted. The results of emissions testing shall be submitted to the DAQ within thirty (30) days of completion of testing.

4.3.2. Within 120 days of startup of the dry ash handling system, the permittee shall perform or have performed EPA approved tests (or other methods as approved by WVDAQ) to determine maximum PM emissions from any one of the Silo Bin Vent Filters (BVF-A, BVF-B or BVF-C).

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 the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.1. of this permit, the permittee shall maintain monthly records of the amount of limestone transferred across the monitored belt conveyors.

4.4.5. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.2. of this permit, the permittee shall maintain monthly records of the amount of gypsum and wastewater treatment cake transferred across the monitored belt conveyors.

4.4.6. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.3. of this permit, the permittee shall maintain monthly records of the amount of coal transferred across the monitored belt conveyor.

4.4.7. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.4. of this permit, the permittee shall maintain monthly records of the amount of dry sorbent (trona and hydrated lime) and liquid magnesium hydroxide delivered to the facility via truck.

4.4.8. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.5. of this permit, the permittee shall maintain monthly records of the amount of hydrated lime, ferric chloride, acid (hydrochloric or sulfuric), polymer and organosulfide delivered to the facility via truck.

4.4.9. For the purpose of demonstrating compliance with the monitoring requirements set forth in Section 4.2.6. of this permit, the permittee shall maintain monthly records of the hours of operation of the diesel-fired engines [6S and 7S].

4.4.10. For the purposes of determining compliance with Section 4.1.16., 4.1.17., and 4.1.18. of this permit, the permittee shall maintain records of the amount of dust control additive used at the facility and the dates the solution was applied.

4.4.11. All records produced in accordance to the requirements set forth by Section 4.4. of this permit shall be maintained on-site for a period of no less than five (5) years and made available to the Director or his duly authorized representative upon request. At a time prior to being submitted to the Director, all records shall be certified and signed by a "Responsible Official" or a duly authorized representative, utilizing the attached Certification of Data Accuracy statement.

4.4.12. For the purposes of determining compliance with the maximum throughput limit set forth in Condition 4.1.20 above, the facility shall maintain monthly (and calculated rolling yearly total) records of the amount of fly ash handled by the Units 1 and 2 fly ash system.

5.0. Source-Specific Requirements for the Auxiliary Boiler (Aux-1)

5.1. Limitations and Standards

5.1.1. The following conditions and requirements are specific to the Boiler Aux-1:

a. Emissions from the boiler shall not exceed the following limits:

Pollutant	lb/hr	tpy
SO_2	39.78*	17.42
NO_x	99.45	43.56
CO	206.86	90.60
VOC	0.95	0.41
PM (filterable +condensable.)	15.63	6.85
PM_{10} (filterable +condensable)	10.90	4.77
$PM_{2.5}$ (filterable +condensable)	7.34	3.22
CO_2	105,606.4	46,255.6
N_2O	0.88	0.38
CH_4	4.38	1.92
CO_{2e} (Total)	105,971.18	46,413.72
Formaldehyde	0.29	0.13
Benzene	0.01	0.01
Ethylbenzene	0.01	0.01
Toluene	0.03	0.02
Xylene	0.01	0.01
Naphthalene	0.01	0.01

* This limit makes 40 CFR §60.42b(k)(2) applicable and excludes the unit from limitations of 40 CFR §60.42b(k)(1). This limit satisfies the limitation in 45 CSR §10-3.1.b.

b. Boiler Aux-1 shall be fitted with Low NO_x burners and shall utilize Flue Gas Recirculation.

c. The permittee shall limit the annual capacity of the boiler to no more than 10 percent by limiting the annual average heat input of the boiler to 580,788 MMBtu per year. Compliance with this limit shall be satisfied though compliance with the annual fuel usage limit in item d of this condition.
[40 CFR §60.44b(c) and §63.7575; and 45 CSR §2-8.4.a.1.]

d. For the purpose of complying with the SO_2 limits in item a of this condition, the Boiler Aux-1 shall not consume more than 4,736 gallons of fuel oil (distillate oil) per hour nor more than 4,148,736 gallons per year. Such fuel oil can not contain more than 600 ppm or 0.06 % of

sulfur, which makes the sulfur dioxide potential for this unit at no greater than 0.06 lb/MMBtu.
[40 CFR §60.42.b(k)(2), §60.43b(h)(5), and §60.48b(j)(2); and 45 CSR §10-10.2]

e. Opacity from boiler shall not exceed 20% based on a 6-minute average, except for one 6-minute period per hour of not more than 27% opacity, except during periods of startup, shutdown, or malfunction.
[40 CFR §§60.43b(f) & (g)]

f. Visible emissions from the boiler shall not exceed 10 percent opacity based on a six minute block average, except during periods of startup, shutdown, or malfunction.
[45 CSR §2-3.1, and §2-9.1.]

g. The permittee shall conduct an initial tune-up of the unit before January 31, 2016 (40 CFR §63.7510(e)) and subsequent tune-ups once every 5 years thereafter in accordance with the applicable requirements of 40 CFR 63, Subpart DDDDD. Subsequent tune-ups shall be conducted no later than 61 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 72 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 (you 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 maintain;

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]

5.1.2. **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.]

5.2. Monitoring Requirements

5.2.1. In order to determine compliance with Condition 5.1.1.d of this permit, the permittee shall monitor and record the amount of fuel oil combusted by Boiler Aux-1 on a monthly basis. Compliance with fuel usage limitations in item d will constitute compliance with the emission limitations of item a. of Condition 5.1.1. Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.49b(d)(2); and 45 CSR §2-8.3c., §§10-8.2.c.3., and 8.3.c.]

5.2.2. The permittee shall obtain records indicating the fuel oil received at the facility for Boiler Aux I meets the specification of distillate oil as defined in 40 CFR §60.41b and sulfur content stated in item d. of Condition 5.1.1. from the fuel supplier. Such records shall be maintained in accordance with Condition 3.4.1.
[40 CFR §60.49b(r)(1) and 45 CSR §§10-8.2.c.3.]

5.2.3. The permittee shall conduct subsequent visible emission observations of the emission point for Boiler Aux-1 at least once every 12 months from the date of the most recent observation. Such observations be conducted using Method 9 of Appendix A-4 of Part 60. If visible emissions are observed, the permittee must follow the subsequent observation schedule in 40 CFR §60.48b(a)(1)(ii) through (iv) as applicable. Record of Method 9 observation shall contain the following:

a. Dates and time intervals of all opacity observation periods;

b. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

c. Copies of all visible emission observer opacity field data sheets;

If the most recent observation is less than 10 percent opacity, the permittee may use Method 22 of Appendix A-7 of Part 60 to demonstrate compliance in lieu of using Method 9. The use of Method 22 observations must be in accordance with the length of observation and frequency as outline in 40 CFR §60.48b(a)(2)(i) through (ii) as applicable. Record of Method 9 observation shall contain the following

a. Dates and time intervals of all visible emissions observation periods;

b. Name and affiliation for each visible emission observer participating in the performance test;

c. Copies of all visible emission observer opacity field data sheets; and

d. Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

Records of observations shall be maintained in accordance with Condition 3.4.1.
[40 CFR §§60.48b(a) and 60.49b(f); and 45 CSR §2-8.1(a)]

5.3. Testing Requirements

[Reserved]

5.4. Recordkeeping Requirements

5.4.1. **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.

5.4.2. **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.

5.4.3. **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.

5.4.4. The permittee shall keep the following records in accordance with 40CFR§63.7555. This includes but not limited to the following information during the tune up as required in Condition 4.1.1.g. and 40 CFR §63.7540:

a. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater. If concentrations of NO_x were taken during the tune-up of the unit, record of such measurements shall be included;

b. A description of any corrective actions taken as a part of the tune-up; and.
[40 CFR §§63.7540(a)(10)(vi) and 63.7555]

5.5. Reporting Requirements

5.5.1. The permittee shall submit a "Notification of Compliance Status" for Boiler Aux-1 to the Director before the close of business on the sixtieth (60^{th}) day after completion of the initial compliance demonstration as required in 40 CFR §63.7530(f). Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the information specified in 40 CFR §§63.7545(e)(1), and (8), which included a statement the initial tune-up for boiler was completed.
[40CFR§63. 7530(d), and §63. 7545(e)]

5.5.2. The permittee shall submit "5- year Compliance Reports" to the Director for Boiler Aux-1 with the first report being submitted by no later than January 31, 2016, and subsequent reports are due every 5 years from 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 biennial 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)]

5.5.3. The permittee shall report any observation made in accordance with Condition 5.2.3. that indicate visible emissions in excess of either items e and/or f of Condition 5.1.1. made during January 1 to June 30 in the facility's Title V Semi Annual Compliance Report or July 1 to December 31 as part of the facility's Title V Annual Compliance Report. Such report shall include the record of the recorded observation in accordance with Condition 5.2.3. and measures taken as result of the observation. This reporting requirement can be satisfied by including the results of the exceeded observation(s) with the facility's quarterly opacity report and list the exceedance in the facility's Title V annual compliance certification report.
[40 CFR §60.49b(h) and 45 CSR §2-8.3b.]

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.

west virginia department of environmental protection
Division of Air Quality

Phase II Acid Rain Permit

Plant Name: **Mitchell Power Station**		Permit #: **R33-3948-2027-6**
Affected Unit(s): **1, 2**		
Operator: **Kentucky Power Company**		ORIS Code: **3948**
Effective Date	From: **January 1, 2023**	To: **December 31, 2027**

Contents:

1. Statement of Basis.

2. SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3. Comments, notes and justifications regarding permit decisions and changes made to permit application forms during the review process, and any additional requirements or conditions.

4. The permit application forms submitted for this source, as corrected by the West Virginia Division of Air Quality. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

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1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with W. Va. Code §22-5-4(a)(16) and Titles IV and V of the Clean Air Act, the West Virginia Department of Environmental Protection, Division of Air Quality issues this permit pursuant to 45CSR33 and 45CSR30.

Permit Approval

Laura M. Crowder Digitally signed by: Laura M. Crowder DN: CN = Laura M. Crowder email = Laura.M.Crowder@wv.gov C = US O = West Virginia Department of Environmental Protection OU = Division of Air Quality Date: 2022.12.19 12:21:39 -05'00'

Laura M. Crowder, Director
Division of Air Quality

December 19, 2022
Date

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No.	**1**

SO_2 Allowances	**Year**				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	18995	18995	18995	18995	18995
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A
The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).					

NO_X Requirements	**2023**	**2024**	**2025**	**2026**	**2027**
NO_X Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50
Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers. In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.					

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

Plant Name: **Mitchell Power Station**	Permit #: **R33-3948-2027-6**

2. SO_2 Allocations and NO_x Requirements for each affected unit

Unit No. **2**

SO_2 Allowances	Year				
	2023	**2024**	**2025**	**2026**	**2027**
Table 2 allowances, as adjusted by 40 CFR Part 73	19656	19656	19656	19656	19656
Repowering plan allowances	N/A	N/A	N/A	N/A	N/A
The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. The aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR §72.84).					

NO_X Requirements	2023	2024	2025	2026	2027
NO_X Limit (lb/mmBtu)	0.50	0.50	0.50	0.50	0.50

Pursuant to 40 CFR Part 76 and 45CSR33, the West Virginia Department of Environmental Protection, Division of Air Quality approves a NO_x emissions compliance plan for this unit effective for calendar years 2023, 2024, 2025, 2026 and 2027. Under this plan the unit's actual annual average NO_x emission rate shall not exceed the applicable limitation of 0.50 lb/mmBtu as set forth in 40 CFR §76.5(a)(2) for Group 1, Phase I dry bottom wall-fired boilers.

In addition to the described NO_x compliance plans, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

3. Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:

None.

4. Permit application forms:

Attached.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/3 /202

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☑ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Mitchell (WV)	West Virginia	3948

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Mitchell (WV)
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, a Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision o the Act, including the provisions o title I o the Act relating to applicable National Ambient Air Quality Standards o State Implementation Plans;

(2) Limiting the number o allowances a source can hold; provided, that the number o allowances held by the source shall not affect the source's obligation o comply with any other provisions o the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, o limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date.

am authorized o make this submission o behalf o the owners and operators o the affected source o affected units for which the submission is made. certify under penalty o law that have personally examined, and am familiar with, the statements and information submitted this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best o my knowledge and belief true, accurate, and complete. am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Scott A. Weaver	
Signature Scott A Weaver	Date 4/7/2022

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

Page 1

This submission is: ☐ New ☑ Revised

STEP 1
Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

Plant Name	State	Plant Code
Mitchell	WV	3948

STEP 2

Identify each affected Group 1 and Group 2 boiler using the unit IDs from the current Certificate of Representation covering the facility. Also indicate the boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom, and select the compliance option for each unit by making an 'X' in the appropriate row and column.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	X	X				
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)						
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)						
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)						
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						

STEP 2, cont'd

Plant Name (From Step 1)	Mitchell

	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(i) NO_X Averaging Plan (include NO_X Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_X Averaging (check the NO_X Averaging Plan box and include NO_X Averaging Form))						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						

STEP 3: Identify the first calendar year in which this plan will apply.

January 1, 2019

STEP 4: Read the special provisions and certification, enter the name of the designated representative, sign and date.

Special Provisions

General. This source is subject to the standard requirements in 40 CFR 72.9. These requirements are listed in this source's Acid Rain Permit.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Scott A. Weaver	
Signature	Scott A Weaver	Date 12-18-18

West Virginia Department of Environmental Protection

Joe Manchin, III
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Class II General Permit G60-C Registration to Modify

for the
Prevention and Control of Air Pollution in regard to the
Construction, Modification, Relocation, Administrative Update and
Operation of Emergency Generators

The permittee identified at the facility listed below is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of General Permit G60-C.

G60-C057A

Issued to:
AEP Generation Resources Inc.
Mitchell Plant
051-00005

William F. Durham
Director

Issued: August 8, 2014

This Class II General Permit Registration will supercede and replace G60-C057.

Facility Location:	State Route 2, Moundsville, Marshall County, West Virginia
Mailing Address:	P.O. Box K Moundsville, WV 26041
Facility Description:	Electric Generation Facility
NAICS Codes:	221112
UTM Coordinates:	516.0 km Easting • 4,409.0 km Northing • Zone 17
Registration Type:	Modification
Description of Change:	Installation of two additional generators (EG-1 and EG-2) to black start the facility.

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 or registration 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.

Unless otherwise stated WVDEP DAQ did not determine whether the permittee is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart ZZZZ.

All registered facilities under Class II General Permit G60-C are subject to Sections 1.0, 2.0, 3.0, and 4.0.

The following sections of Class II General Permit G60-C apply to the registrant:

Section 5	Reciprocating Internal Combustion Engines (R.I.C.E.)	X
Section 6	Tanks	X
Section 7	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40CFR60 Subpart IIII)	X
Section 8	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (40CFR60 Subpart JJJJ)	X

Emission Units

Emission Unit ID	Emission Unit Description (Make, Model, Serial No.)	Year Installed	Design Capacity (Bhp/rpm)
LPG	Generac SG080, 127 BHP Engine (Spark Ignition Engine)	2013	127/1,800
EG-1	CAT® C175-16 (Compression Ignition (CI) Engine) Certificate No. ECPXL106.NZS-011 Engine ECPXL106.NZS	2014	3,717/1,800
EG-2	CAT® 3516C-HD TA (CI Engine) Certificate No. ECPXL78.1NZS-024 Engine ECPXL78.1NZS	2014	3,004/1,800

Emission Limitations

Source ID#	Nitrogen Oxides		Carbon Monoxide		Volatile Organic Compounds	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
LPG	0.74	0.19	21.75	5.44	0.22	0.06
EG-1	59.9	14.98	7.66	1.92	0.94	0.24
EG-2	36.4	9.1	4.85	1.21	1.18	0.03
TOTAL	97.04	24.27	34.26	8.57	2.34	0.33

West Virginia Department of Environmental Protection

Austin Caperton
Cabinet Secretary

Class II General Permit
G60-D

for the
Prevention and Control of Air Pollution in regard to the
Construction, Modification, Relocation, Administrative Update and
Operation of Emergency Generators

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45CSR13 — Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation.

William F. Durham
Director, Division of Air Quality

Issued: May 9, 2018

Class II General Permit G60-D supersedes and replaces General Permit G60-C issued on May 21, 2009.

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.

General Permit G60-D authorizes the construction, modification, administrative update and/or operation of emergency generators.

Table of Contents

1.0. Emission Units

1.1. General Permit Registration

1.1.1. All emission units covered by this permit are listed on the issued G60-D Registration.

2.0. General Conditions

2.1. Purpose

The purpose of this Class II General Permit is to authorize the construction, modification, administrative update, relocation, and operation of eligible emergency generators through a Class II General Permit registration process. The requirements, provisions, standards and conditions of this Class II General Permit address the prevention and control of regulated pollutants from the operation of emergency generator(s).

2.2. Authority

This permit is issued in accordance with West Virginia air pollution control law W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.2.1. 45 CSR 13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation.*

2.3. Applicability

2.3.1. All emergency generators installed for the purpose of allowing key systems to continue to operate without interruption during times of utility power outages, including emergency generators installed at Title V(major) facilities and other facilities having additional point sources of emissions, are eligible for Class II General Permit registration except for:

a. Any emergency generator which is a major source as defined in 45CSR14, 45CSR19 or 45CSR30;
b. Any emergency generator subject to the requirements of 45CSR14, 45CSR15, 45CSR19, 45CSR25, 45CSR27, 45CSR30, 45CSR34;
c. Any emergency generator whose estimated hours of operation exceeds 500 hours per year;
d. Any emergency generator located in or which may significantly impact an area which has been determined to be a nonattainment area. Unless otherwise approved by the Secretary.
e. Any emergency generator which will require an individual air quality permit review process and/or individual permit provisions to address the emission of a regulated pollutant or to incorporate regulatory requirements other than those established by General Permit G60-D.
f. Any emergency generator which is/are part of an emergency demand response program.

2.3.2. For the purposes of General Permit G60-D, *emergency generator* means a generator whose purpose is to allow key systems to continue to operate without interruption during times of utility power outages.

2.3.3. The West Virginia Division of Air Quality reserves the right to reopen this permit or any authorization issued under this permit if the area in which the affected facility is located is federally designated as non-attainment for specified pollutants. If subsequently any proposed construction, modification and/or operation does not demonstrate eligibility and/or compliance with the requirements, provisions, standards and conditions of this General Permit, this General

Permit registration shall be denied and an individual permit for the proposed activity shall be required.

2.3.4. Except for emergency diesel generators, all emission units covered by this permit, unless they are classified as De Minimis Sources in 45CSR13 Table 45-13B, must be fueled with pipeline-quality natural gas, field gas, propane gas, or equivalent with a maximum sulfur content of 20 grains of sulfur per 100 standard cubic feet and a maximum H_2S content of 0.25 grains per 100 cubic feet of gas (maximum allowed to have in natural gas sold for delivery through the interstate pipeline system).
[45CSR§13-5.11]

2.4. Definitions

2.4.1. 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.

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

2.4.3. "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.

2.4.4. The terms established in applicable definitions codified in the Code of Federal Regulations including 40 CFR Part 60 NSPS Subparts A, IIII and JJJJ or 40 CFR Part 63 MACT Subparts A and ZZZZ shall also apply to those sections of General Permit G60-D where these subparts are incorporated or otherwise addressed.

2.5. Acronyms

CAAA	Clean Air Act Amendments	NO_x	Nitrogen Oxides
CBI	Confidential Business Information	NSCR	Non Selective Catalytic Reduction
CEM	Continuous Emission Monitor	NSPS	New Source Performance Standards
CES	Certified Emission Statement		
CFR	Code of Federal Regulations	PM	Particulate Matter
CO	Carbon Monoxide	$PM_{2.5}$	Particulate Matter less than 2.5 µm in diameter
CSR	Code of State Rules		
DAQ	Division of Air Quality	PM_{10}	Particulate Matter less than 10 µm in diameter
DEP	Department of Environmental Protection	ppm	Parts per million
FOIA	Freedom of Information Act	ppm_v	Parts per million by Volume
HAP	Hazardous Air Pollutant	PSD	Prevention of Significant Deterioration
HP	Horsepower		
lb/hr	Pounds per hour	psi	Pounds per square inch
LDAR	Leak Detection and Repair	RICE	Reciprocating Internal Combustion Engine
M or m	Thousand		
MACT	Maximum Achievable Control Technology	SCR	Selective Catalytic Reduction
		SIC	Standard Industrial Classification
MDHI	Maximum Design Heat Input		
MM or mm	Million	SIP	State Implementation Plan
MMBTU/hr	Million British Thermal Units Per Hour	SO_2	Sulfur Dioxide
		TAP	Toxic Air Pollutant
MMCF/hr	Million Cubic Feet per Hour	TPY	Tons per year

N/A	Not Applicable	TSP	Total Suspended Particulate
NAAQS	National Ambient Air Quality Standards	USEPA	United States Environmental Protection Agency
NESHAPS	National Emissions Standards for Hazardous Air Pollutants	UTM	Universal Transverse Mercator
		VEE	Visual Emissions Evaluation
LAT	Latitude	VOC	Volatile Organic Compounds
LON	Longitude	VRU	Vapor Recovery Unit

2.6. Permit Expiration and Renewal

2.6.1. This Class II General 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.

2.6.2. General Permit registrations granted by the Secretary shall remain valid, continuous and in effect unless suspended or revoked by the Secretary. If the Class II General Permit registration is subject to action or change, existing registrations will continue to be authorized and subject to the previously established permit conditions. **[45CSR§13-10.2, 45CSR§13-10.3]**

2.6.3. The Secretary shall review and may renew, reissue or revise this Class II General Permit for cause. The Secretary shall define the terms and conditions under which existing General Permit registrations will be eligible for registration under a renewed, reissued, or revised General Permit and provide written notification to all General Permit registrants (or applicants). This notification shall also describe the registrant's (or applicant's) duty or required action and may include a request for additional information that may be required by any proposed general permit renewal, reissuance or revision.

2.7. Administrative Update to General Permit Registration

2.7.1. The registrant may request an administrative update to their General Permit registration as defined in and according to the procedures specified in 45CSR§13-4.
[45CSR§13-4.]

2.8. Modification to General Permit Registration

2.8.1. The registrant may request a minor permit modification to their General Permit registration as defined in and according to the procedures specified in 45CSR§13-5. **[45CSR§13-5.]**

2.9. Duty to Comply

2.9.1. The registered affected facility shall be constructed and operated in accordance with the information filed in the General Permit Registration Application and any amendments thereto. The Secretary may suspend or revoke a General Permit registration if the plans and specifications upon which the approval was based are not adhered to.

2.9.2. The registrant must comply with all applicable conditions of this Class II General Permit. Any General Permit noncompliance constitutes a violation of the West Virginia Code, and/or the Clean Air Act, and is grounds for enforcement action by the Secretary or USEPA.

2.9.3. Violation of any of the applicable requirements, provisions, standards or conditions contained in this Class II General Permit, or incorporated herein by reference, may subject the registrant 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.

2.9.4. Registration under this Class II General Permit does not relieve the registrant 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.

2.10. Inspection and Entry

2.10.1. The registrant 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 enter upon the registrant'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 Class II General 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 this Class II General Permit;

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.

2.11. Need to Halt or Reduce Activity not a Defense

2.11.1. It shall not be a defense for a registrant in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Class II General 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.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonably 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 this Class II General 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. In any enforcement proceeding, the registrant seeking to establish the occurrence of an emergency has the burden of proof.

2.12.3. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Federally-Enforceable Requirements

2.13.1. All terms and conditions in this permit are enforceable by the Secretary, USEPA, and citizens under the Clean Air Act.

2.13.2. Those provisions specifically designated in the permit as "State-enforceable only" shall become "Federally-Enforceable" requirements upon SIP approval by the USEPA.

2.14. Duty to Provide Information

2.14.1. The registrant shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this Class II General Permit Registration or to determine compliance with this General Permit. Upon request, the registrant shall also furnish to the Secretary copies of records required to be kept by the registrant. For information claimed to be confidential, the registrant 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 registrant shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 CFR Part 2.

2.15. Duty to Supplement and Correct Information

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

2.16. Credible Evidence

2.16.1. Nothing in this Class II General 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 defenses otherwise available to the registrant including but not limited to any challenge to the credible evidence rule in the context of any future proceeding.

2.17. Severability

2.17.1. The provisions of this Class II General Permit are severable. If any provision of this Class II General Permit, or the application of any provision of this Class II General Permit to any circumstance is held invalid by a court of competent jurisdiction, the remaining Class II General Permit terms and conditions or their application to other circumstances shall remain in full force and effect.

2.18. Property Rights

2.18.1. Registration under this Class II General Permit does not convey any property rights of any sort or any exclusive privilege.

2.19. Notification Requirements

2.19.1. The registrant shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit except as required under section 1.1.3 (e.g. 15 days after alternative operating scenario startup).

2.20. Suspension of Activities

2.20.1. In the event the registrant should deem it necessary to suspend, for a period in excess of one (1) year, all operations authorized by this permit, the registrant shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the one (1) year of the suspension period.

2.21. Transferability

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

3.0. Facility-Wide Requirements

3.1. Siting Criteria

3.1.1. All persons submitting a Class II General Permit Registration Application to construct, modify or relocate an emergency generator shall be subject to the following siting criteria:

a. No emission unit shall be constructed, located or relocated within 300 feet of any occupied dwelling, business, public building, school, church, community building, institutional building or public park. An owner of an occupied dwelling or business may elect to waive the 300 foot siting criteria.

b. Any person proposing to construct, modify or relocate any emission unit(s) within 300 feet of any occupied dwelling, business, public building, school, church, community, institutional building or public park may elect to apply for an individual permit pursuant to 45CSR13.

3.2. Limitations and Standards

3.2.1. **Open burning.** The open burning of refuse by any person is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.2.2. **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 or allow 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.]

3.2.3. **Asbestos.** The registrant 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 CFR § 61.145, 40 CFR § 61.148, and 40 CFR § 61.150. The registrant, 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 registrant is subject to the notification requirements of 40 CFR § 61.145(b)(3)(i). USEPA, the Division of Water and Waste Management (DWWM), and the Department of Health and Human Resources (DHHR) – Office of Environmental Health Services (OEHS) require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.2.4. **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]***

3.2.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one, twelve (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. *This requirement does not apply to emergency generator(s) permitted to operate only 500 hours per year.*
[45CSR§13-10.5.]

3.2.6. **Standby plan for reducing emissions.** When requested by the Secretary, the registrant 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.]

3.3. Monitoring Requirements

See Section 4.2.

3.4. Testing Requirements

3.4.1. **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 registrant shall conduct test(s) to determine compliance with the emission limitations set forth in this Class II General Permit and/or established or set forth in underlying documents. The Secretary, or their duly authorized representative, may at his/her option witness or conduct such test(s). Should the Secretary exercise his/her 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 CFR 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 Class II General 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 require, approve or specify additional testing or alternative testing to the test methods specified in the Class II General 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 3.4.1.a. of this general 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 Class II General Permit shall be conducted in accordance with an approved test protocol. 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 registrant 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 registrant 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 and any operating parameters required to be monitored. The report shall include the following: the certification described in paragraph 3.6.1; 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]

3.5. Recordkeeping Requirements

3.5.1. **Retention of records.** The registrant 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. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Said records shall be maintained on site or in a readily accessible off-site location maintained by the registrant for a period of five (5) years. Said records shall be readily available to the Secretary of the Division of Air Quality or his/her duly authorized representative for expeditious inspection and review. Any records submitted to the agency pursuant to a requirement of this permit or upon request by the Secretary shall be certified by a responsible official. Where appropriate, the registrant may maintain records electronically.

3.5.2. **Odors.** For the purposes of 45CSR4, the registrant 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.*]**

3.6. Reporting Requirements

3.6.1. **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.

3.6.2. **Confidential information.** A registrant 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.

3.6.3. **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, e-mailed 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 SE
Charleston, WV 25304-2345
-or-
DEPAirQualityReports@wv.gov
(preferred)

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

3.6.4. **Emission inventory.** At such time(s) as the Secretary may designate, the registrant 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 DAQ. 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.

3.6.5. **Operating Fee**

The registrant will be subject to (a) or (b) below dependent on the source status of the facility:

(a) In accordance with 45CSR22 – Air Quality Management Fee Program, the registrant shall not operate nor cause to operate the permitted facility or other associated facilities on the same or contiguous sites comprising the plant without first obtaining and having in current effect a Certificate to Operate (CTO). Such Certificate to Operate (CTO) shall be renewed annually, shall be maintained on the premises for which the certificate has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

(b) 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.

4.0. Source-Specific Requirements

4.1. Limitations and Standards

4.1.1. *Operation and Maintenance of Air Pollution Control Equipment and Emission Reduction Devices.* The registrant shall, to the extent practicable, install, maintain, and operate all pollution control equipment and emission reduction devices listed in the issued General Permit Registration and associated monitoring equipment to comply with limits set forth in this General Permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary. **[45CSR§13-5.11.]**

4.1.2. *Applicability of State and Federal Regulations.* The registrant is subject to the provisions of the following State Rules and Federal Regulations, to the extent applicable based on its registration:

a. 45CSR13 - Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, and Procedures for Evaluation
b. 45CSR16 - Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60
c. 45CSR22 - Air Quality Management Fee Program
d. 45CSR30 – Requirements for Operating Permits
e. 40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
f. 40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
g. 40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

4.2. Recordkeeping Requirements

4.2.1. *Monitoring information.* The registrant 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.

4.2.2. *Record of Maintenance of Air Pollution Control Equipment and Emission Reduction Devices.* For all pollution control equipment and emission reduction devices listed in the General Permit Registration, the registrant shall maintain accurate records of all required pollution control equipment and emission reduction devices inspection and/or preventative maintenance procedures specifically required in this General Permit.

4.2.3. *Record of Malfunctions of Air Pollution Control Equipment and Emission Reduction Devices.* For all air pollution control equipment and emission reduction devices listed in the General Permit Registration, the registrant shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment and emission reduction devices during which excess emissions above the applicable permit limit 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.

5.0. Source-Specific Requirements [Reciprocating Internal Combustion Engine(s) (RICE)]

5.1. Limitations and Standards

5.1.1. For the purposes of General Permit G60-D, *emergency generator* means a generator whose purpose is to allow key systems to continue to operate without interruption during times of utility power outages.

5.1.2. *Regulated Pollutant Limitation.* The registrant shall not cause, suffer, allow or permit emissions of any regulated pollutant listed in the General Permit Registration to exceed the emission limit (pounds per hour and tons per year) recorded with the registrant's General Permit Registration. The registrant may request a modification or administrative update to these emission limits.

5.1.3. *Maximum Hourly Limitation.* The maximum hours of operation for any registered emergency generator listed in the General Permit Registration application shall not exceed 500 hours per year. Compliance with the Maximum Yearly Hourly Operation Limitation shall be determined using a twelve-month rolling total. A twelve-month rolling total shall mean the sum of the hours or operation at any given time during the previous twelve consecutive calendar months.

5.1.4. The applicable emergency generator(s) shall be operated and maintained as follows:

a. In accordance with the manufacturer's recommendations and specifications or in accordance with a site specific maintenance plan; and,
b. In a manner consistent with good operating practices.

5.1.5. Requirements for Use of Catalytic Reduction Devices

a. Rich-burn engine(s) equipped with non-selective catalytic reduction (NSCR) air pollution control devices shall be fitted with a closed-loop, automatic air/fuel ratio controller to ensure emissions of regulated pollutants do not exceed the emission limit listed in the General Permit Registration for any engine/NSCR combination under varying load. The closed-loop, automatic air/fuel ratio controller shall control a fuel metering valve to ensure a fuel-rich mixture and a resultant exhaust oxygen content of less than or equal to 2%.

b. Lean-burn engine(s) equipped with selective catalytic reduction (SCR) air pollution control devices shall be fitted with a closed-loop automatic feedback controller to ensure emissions of regulated pollutants do not exceed the emission limit listed in the General Permit Registration for any engine/SCR combination under varying load. The closed-loop automatic feedback controller shall provide proper and efficient operation of the engine, ammonia injection and SCR device, monitor emission levels downstream of the catalyst element and limit ammonia slip to less than 10 ppm_v.

c. Lean-burn engine(s) equipped with oxidation catalyst air pollution control devices shall be fitted with a closed-loop automatic air/fuel ratio feedback controller to ensure emissions of regulated pollutants do not exceed the emission limit listed in the General Permit Registration for any engine/oxidation catalyst combination under varying load. The closed-loop, automatic air/fuel ratio controller shall control a fuel metering valve to ensure a lean-rich mixture.

d. For engine(s) equipped with a catalyst, the registrant shall monitor the temperature to the inlet of the catalyst and in accordance with manufacturer's specifications; a high temperature alarm shall shut off the engine before thermal deactivation of the catalyst occurs. If the engine shuts off due to high temperature, the registrant shall also check for thermal deactivation of the catalyst before normal operations are resumed.

e. The registrant shall follow a written operation and maintenance plan that provides the periodic and annual maintenance requirements.

5.1.6. The registrant shall comply with all applicable NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

5.1.7. The emission limitations specified in section 5.1.2 shall apply at all times except during periods of start-up and shut-down provided that the duration of these periods does not exceed 30 minutes per occurrence. The registrant shall operate the engine in a manner consistent with good air pollution control practices for minimizing emissions at all times, including periods of start-up and shut-down. The emissions from start-up and shut-down shall be included in the twelve (12) month rolling total of emissions. The registrant shall comply with all applicable start-up and shut-down requirements in accordance with 40 CFR Part 60, Subparts IIII, JJJJ and 40 CFR Part 63, Subpart ZZZZ.

5.2. Monitoring Requirements

5.2.1. Catalytic Reduction Devices

a. The registrant shall regularly inspect, properly maintain and/or replace catalytic reduction devices and auxiliary air pollution control devices to ensure functional and effective operation of the engine's physical and operational design. The registrant shall ensure proper operation, maintenance and performance of catalytic reduction devices and auxiliary air pollution control devices by:

1. Maintaining proper operation of the automatic air/fuel ratio controller or automatic feedback controller.

2. Following the catalyst manufacturer emissions related operating and maintenance recommendations, or develop, implement, or follow a site-specific maintenance plan.

5.3. Recordkeeping Requirements

5.3.1. To demonstrate compliance with general permit condition 5.1.3, the registrant shall maintain records of the hours of operation of the emergency generator(s) on a monthly basis.

5.3.2. To demonstrate compliance with general permit section 5.1.4, the registrant shall maintain records of the maintenance performed on each emergency generator.

5.3.3. To demonstrate compliance with general permit sections 5.2.1, the registrant shall maintain a copy of the site specific maintenance plan or manufacturer maintenance plan.

5.3.4. The registrant shall comply with all applicable recordkeeping requirements under NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

5.3.5. All records required by this section shall be maintained in accordance with section 3.5.1 of this general permit.

5.4. Testing Requirements

5.4.1. The registrant shall comply with all applicable testing requirements under NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

5.4.2. To demonstrate compliance with general permit section 5.1.5(a), the registrant shall verify that the closed-loop, automatic air/fuel ratio controller shall control a fuel metering valve to ensure a fuel-rich mixture and a resultant exhaust oxygen content of less than or equal to 2% during any performance testing.

5.5. Reporting Requirements

5.5.1. The registrant shall comply with all applicable notification requirements under NSPS for Stationary Compression Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart IIII, Stationary Spark Ignition Internal Combustion Engines specified in 40 CFR Part 60, Subpart JJJJ, and/or the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines specified in 40 CFR Part 63, Subpart ZZZZ.

6.0. Source-Specific Requirements (Tanks)

6.1. Limitations and Standards

6.1.1. All tanks in the General Permit Registration application will be listed in Section 1.0 (the emission unit table) of the issued registration. Tanks are to be used for fuel storage for the emergency generators only.

6.2. Monitoring Requirements

6.2.1. See Facility-Wide Monitoring Requirements.

6.3. Testing Requirements

6.3.1. See Facility-Wide Testing Requirements.

6.4. Recordkeeping Requirements

6.4.1. See Facility-Wide Recordkeeping Requirements.

6.5. Reporting Requirements

6.5.1. See Facility-Wide Reporting Requirements.

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.

Attachment K
45 CSR 2/10 Monitoring Plan

45 CSR 2 and 45 CSR 10
Monitoring and Recordkeeping Plan

Mitchell Plant

Facility Information:

Facility Name: Mitchell Plant

Facility Address: P.O. Box K
State Route 2
Moundsville, WV 26041

Facility Environmental Contact: Mr. G. M. (Matt) Palmer
–Plant Environmental Coordinator

A. Facility Description:

Mitchell Plant is a coal-fired electric generating facility with two main combustion units (Units 1 and 2) discharging through a common stack shell that utilizes two separate stack discharge flues. Mitchell plant also has an auxiliary boiler (Aux. 1) that discharges through an independent auxiliary stack (aux 1). Unit 1, Unit 2, and Aux. Boiler 1 each have a design heat input greater than 10 mmBTU/hr making both 45 CSR 2A (Interpretive Rule for 45 CSR 2) and 45 CSR 10A (Interpretive Rule for 45 CSR 10) applicable to these sources.

I. 45 CSR 2 Monitoring Plan:

In accordance with Section 8.2.a of 45 CSR 2, following is the proposed plan for monitoring compliance with opacity limits found in Section 3 of that rule:

A. Main Stack (CS012)

1. Applicable Standard:

45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method(s):

45 CSR 2, §3.2 …*Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emissions control.*

45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

a. Primary Monitoring Method: While a Continuous Opacity Monitoring System (COMS) would not be required on a wet scrubbed fuel burning unit, Mitchell Plant has chosen to employ COMS on each of the fuel burning units upstream of the wet scrubbers and located in plant ductwork. As such, the primary method of monitoring opacity at Mitchell Plant will be Continuous Opacity Monitors (COMS). The COMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75.

b. Other Credible Monitoring Method(s): While Mitchell Plant will use COMS as the primary method of monitoring opacity of the fuel burning units, we are also reserving the right to use other appropriate method that would produce credible data. These “other monitoring methods” will generally be used in the absence of COMS data or as other credible evidence used in conjunction with COMS data.

3. Recordkeeping:

a. **Operating Schedule and Quality/Quantity of Fuel Burned**

45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

The applicable paragraphs for Mitchell Plant are the following:

§7.1.a.2: *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

§7.1.a.4: *For fuel burning unit(s) which burn only coal, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a daily basis and an ash and BTU analysis for each shipment.*

§7.1.a.6: *For fuel burning unit(s) which burn a combination of fuels, the owner or operator shall comply with the applicable Recordkeeping requirements of paragraph 7.1.a.1 through 7.1.a.5 for each fuel burned.*

The date and time of each startup and shutdown of Units 1 and 2 will be maintained. The quantity of coal burned on a daily basis as well as the ash and Btu content will also be maintained. From a fuel oil perspective, the quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

b. **Record Maintenance**

45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.

4. Exception Reporting:

a. **Particulate Mass Emissions:**

45 CSR 2A, §7.2.a. *With respect to excursions associated with measured emissions under Section 4 of 45CSR2, compliance with the reporting and testing requirements under the Appendix to 45CSR2 shall fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45CSR2.*

Mitchell Plant will comply with the reporting and testing requirements specified under the Appendix to 45 CSR 2.

b. **Opacity:**

45 CSR 2A, §7.2.b. *COMS – In accordance with the provisions of this subdivision, each owner or operator employing COMS as the method of monitoring compliance with opacity limits shall submit a "COMS Summary Report" and/or an "Excursion and COMS Monitoring System Performance Report" to the Director on a quarterly basis; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the* *fuel burning unit(s). All reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter. The COMS Summary Report shall contain the information and be in the format shown in Appendix B unless otherwise specified by the Director.*

45 CSR 2A, §7.2.b.1. *If the total duration of excursions for the reporting period is less than one percent (1%) of the total operating time for the reporting period and monitoring system downtime for the reporting period is less than five percent (5%) of the total operating time for the reporting period, the COMS Summary Report shall be submitted to the Director; the Excursion and COMS Monitoring System Performance report shall be maintained on-site and shall be submitted to the Director upon request.*

45 CSR 2A, §7.2.b.2. *If the total duration of excursions for the reporting period is one percent (1%) or greater of the total operating time for the reporting period or the total monitoring system downtime for the reporting period is five percent (5%) or greater of the total operating time for the reporting period, the COMS Summary Report and the Excursion and COMS Monitoring System Performance Report shall both be submitted to the Director.*

45 CSR 2A, §7.2.b.3. *The Excursion and COMS Monitoring System Performance Report shall be in a format approved by the Director and shall include, but not be limited to, the following information:*

45 CSR 2A, §7.2.b.3.A. *The magnitude of each excursion, and the date and time, including starting and ending times, of each excursion.*

45 CSR 2A, §7.2.b.3.B. *Specific identification of each excursion that occurs during start-ups, shutdowns, and malfunctions of the facility.*

45 CSR 2A, §7.2.b.3.C. *The nature and cause of any excursion (if known), and the corrective action taken and preventative measures adopted (if any).*

45 CSR 2A, §7.2.b.3.D. *The date and time identifying each period during which quality- controlled monitoring data was unavailable, except for zero and span checks, and the reason for data unavailability and the nature of the repairs or adjustments to the monitoring system.*

45 CSR 2A, §7.2.b.3.E. *When no excursions have occurred or there were no periods of quality-controlled data unavailability, and no monitoring systems were inoperative, repaired, or adjusted, such information shall be stated in the report.*

Attached, as Appendices A and B are sample copies of a typical COMS "Summary Report" and "Excess opacity and COM downtime report" that we plan on using to fulfill the opacity reporting requirements. The COMS "Summary Report" will satisfy the conditions under 45 CSR 2A, §7.2.b for the "COMS Summary Report" and will be submitted to the Director according to its requirements. The "Excess opacity and COM downtime report" satisfies the conditions under 45 CSR 2A, §7.2.b.3. for the "Excursion and COMS Monitoring System Performance Report". The "Excess opacity and COM downtime report" shall be submitted to the Director following the conditions outlined in 45 CSR 2A, §7.2.b.1. and §7.2.b.2.

To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

B. **Aux. Stack (aux 1)**

1. Applicable Standard:

45 CSR 2, §3.1. *No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.*

2. Monitoring Method:

45 CSR 2, §8.2.a.1. *Direct measurement with a certified continuous opacity monitoring system (COMS) shall be deemed to satisfy the requirements for a monitoring plan. Such COMS shall be installed, calibrated, operated and maintained as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS1). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS1.*

45 CSR 2, §8.4.a. *The owner or operator of a fuel burning unit(s) may petition for alternatives to testing, monitoring, and reporting requirements prescribed pursuant to this rule for conditions, including, but not limited to, the following:*

45 CSR 2, §8.4.a.1. *Infrequent use of a fuel burning unit(s)*

Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack. Based on limited operating hours, the requirement for COMS installation per Section 6.2.a of interpretive rule 45 CSR 2A was determined to be overly-burdensome and sufficient reason for the granting of alternative monitoring methods. The alternative monitoring method based on USEPA Method 9 visible emission readings is described below.

- Primary Monitoring Method: As an alternative to COMS monitoring, a Method 9 reading will be conducted one time per month provided the following conditions are met: 1) The auxiliary boiler has operated at normal, stable load conditions for at least 24 consecutive hours and 2) weather/lighting conditions are conducive to taking proper Method 9 readings. Since the Mitchell auxiliary boiler does not utilize post-combustion particulate emissions controls, operating parameters of control equipment are nonexistent and therefore unable to be monitored.

3. Recordkeeping:

   a. **Operating Schedule and Quality/Quantity of Fuel Burned**

   45 CSR 2A §7.1.a. *The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified in paragraphs 7.1.a.1 through 7.1.a.6, as applicable.*

   The applicable paragraph for the Mitchell Plant auxiliary boilers follows:

   > **§7.1.a.2:** *For fuel burning unit(s) which burn only distillate oil, such records shall include, but not be limited to, the date and time of start-up and shutdown, the quantity of fuel consumed on a monthly basis and a BTU analysis for each shipment.*

   As such, the date and time of each startup and shutdown of the auxiliary boiler will be maintained. The quantity of fuel oil burned on a monthly basis, as well as the Btu content will be maintained. The fuel oil analysis will generally be one that is provided by the supplier for a given shipment but in some cases, we may use independent sampling and analyses. The quantity of fuel oil burned on a monthly basis may be maintained on a facility wide basis.

   b. **Record Maintenance**

   45 CSR 2A §7.1.b. *Records of all required monitoring data and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

   Records of all required monitoring data and support information will be maintained on-site for at least five (5) years. In the case of the auxiliary boilers, strip chart recordings, etc. are generally not available.

4. Exception Reporting:

Pursuant to 45 CSR 2, Section 8.4.a and 8.4.a.1, Mitchell Plant previously petitioned the Office of Air Quality (OAQ) Chief for alternative testing, monitoring, and reporting requirements for the auxiliary boiler and associated stack.

a. **Particulate Mass Emissions –** As an alternative to the testing and exception reporting requirements for particulate mass emissions from the auxiliary boiler, the following was previously proposed and approved. Based on an average heat content of approximately 139,877 Btu/gallon (calendar year 2000 data) and an AP-42 based particulate mass emissions emission factor of 2 lbs/thousand gallons, the calculated particulate mass emissions of the auxiliary boiler are 0.01 lb/mmBTU. As such, the fuel analysis records maintained under the fuel quality analysis and recordkeeping section of this plan provide sufficient evidence of compliance with the particulate mass emission limit. For the purpose of meeting exception reporting requirements, any fuel oil analysis indicating a heat content of less than 25,000 Btu per gallon will be reported to the OAQ to fulfill the requirement for a periodic exception report under subdivision 8.3.b. or 45 CSR 2 – 45 CSR 2A, §7.2.a. A heat content of 25,000 Btu/gal and a particulate emissions factor of 2 lbs/thousand gallons would result in a calculated particulate mass emissions of approximately 90% of the applicable 45 CSR 2 standard.

b. **Opacity –** As an alternative to the exception reporting requirements for opacity emissions from the auxiliary boiler, the following was previously proposed and approved. We will maintain a copy of each properly conducted (correct weather/lighting conditions, etc.) Method 9 evaluation performed. Any properly conducted Method 9 test which indicates an exceedance shall be submitted to the OAQ on a quarterly basis (within 30 days of the end of the quarter) along with an accompanying description of the excursion cause, any corrective action taken, and the beginning and ending times for the excursion.

   To the extent that an excursion is due to a malfunction, the reporting requirements in section 9 of 45CSR2 shall be followed – 45 CSR 2A, §7.2.d.

If no exceptions have occurred during the quarter, then a report will be submitted to the OAQ stating so. This will identify periods in which no method 9 tests were conducted (e.g. unit out of service) or when no fuel oil was received.

II. <u>45 CSR 10 Monitoring Plan:</u>

In accordance with Section 8.2.c of 45 CSR 10, following is the proposed plan for monitoring compliance with the sulfur dioxide weight emission standards expressed in Section 3 of that rule:

A. Main Stack (CS012)

1. Applicable Standard:

   45 CSR 10, §3.1.b. *For fuel burning units of the Mitchell Plant of Ohio Power Company, located in Air Quality Control Region I, the product of 7.5 and the total actual operating heat inputs for such units discharging through those stacks in million BTU's per hour.*

   45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

   A new SO_2 limit will likely be established as a result of the installation of the flue gas desulfurization system/new stack configuration and the subsequent NAAQS compliance demonstration modeling. Assuming that revised SO2 limit is more stringent than the current limit expressed in 45 CSR 10, Mitchell Plant SO_2 emissions will be regulated by the more stringent of the two limits.

2. Monitoring Method:

   45 CSR 10, §8.2.c.1. *The installation, operation and maintenance of a continuous monitoring system meeting the requirements 40 CFR Part 60, Appendix B, Performance Specification 2 (PS2) or Performance Specification 7 (PS7) shall be deemed to fulfill the requirements of a monitoring plan for a fuel burning unit(s), manufacturing process source(s) or combustion source(s). CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PS2.*

   a. Primary Monitoring Method: The primary method of monitoring SO_2 mass emissions from the two new stack flues (located within one stack shell) will be Continuous Emissions Monitors (CEMS). Data used in evaluating the performance of the Mitchell Units with the applicable standard will be unbiased, unsubstituted data as specified in definition 45 CSR 10A, §6.1.b.1. Data capture of more than 50% constitutes sufficient data for the daily mass emissions to be considered valid. The CEMS are installed, maintained and operated in compliance with requirements of 40 CFR Part 75. Because Units 1 and 2 will discharge through separate flues and both units are "Type a" fuel burning units as defined in 45 CSR 10, the plant-wide limit is calculated by summing the limits from the two flues.

   b. Other Credible Monitoring Method(s): While Mitchell Plant will use CEMS as the primary method of monitoring SO_2 mass emissions from the two flues, we are also reserving the right to use other appropriate methods that would produce credible data. These "other monitoring methods" will generally be used in the absence of CEMS data or as other credible evidence used in conjunction with CEMS data.

3. Recordkeeping:

   a. **Operating Schedule and Quality/Quantity of Fuel Burned:**

      45 CSR 10A, §7.1.a. *Fuel burning units - The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule and the quality or quantity of fuel burned in each unit…*

      45 CSR 10A, §7.1.c. *The owner or operator of a fuel burning unit or combustion source which utilizes CEMS shall be exempt from the provisions of subdivision 7.1.a. or 7.1.b, respectively.*

      As such, Mitchell plant will not maintain records of the operating schedule and the quality and quantity of fuel burned in each unit for purposes of meeting the requirements for a monitoring plan under 45 CSR 10. While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

   b. **Record Maintenance**

      45 CSR 10A, §7.1.d. *For fuel burning units, manufacturing process sources, and combustion sources, records of all required monitoring data as established in an approved monitoring plan and support information shall be maintained on-site for a period of at least five (5) years from the date of monitoring, sampling, measurement or reporting. Support information includes all calibration and maintenance records and all strip chart recordings for continuous monitoring instrumentation, and copies of all required reports.*

      As such, CEMS records at Mitchell Plant will be maintained for at least five years.

4. Exception Reporting:

   45 CSR 10A, §7.2.a. *CEMS - Each owner or operator employing CEMS for an approved monitoring plan, shall submit a "CEMS Summary Report" and/or a "CEMS Excursion and Monitoring System Performance Report" to the Director quarterly; the Director may, on a case-by-case basis, require more frequent reporting if the Director deems it necessary to accurately assess the compliance status of the source. All reports shall be postmarked no later than forty-five (45) days following the end of each calendar quarter. The CEMS Summary Report shall contain the information and be in the format shown in Appendix A unless otherwise specified by the Director.*

45 CSR 10A, §7.2.a.1. *Submittal of 40 CFR Part 75 data in electronic data (EDR) format to the Director shall be deemed to satisfy the requirements of subdivision 7.2.a.*

As such, Mitchell Plant will submit the 40 CFR 75 quarterly electronic data reports (EDRs) to the OAQ to meet the requirements for a CEMS Summary Report and the CEMS Excursion and Monitoring System Performance Report. The EDR reports will be submitted to the OAQ no later than 45 days following the end of the quarter.

When no excursions of the 24-hour SO_2 standard have occurred, such information shall be stated in the cover letter of the EDR submittal.

B. Aux. Stack (aux 1)

1. Applicable Standard:

45 CSR 10, §3.1.e. *For type 'b' and Type 'c' fuel burning units, the product of 3.1 and the total design heat inputs for such units discharging through those stacks in million BTU's per hour.*

45 CSR 10, §3.8. *Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on continuous twenty-four (24) hour averaging time…A continuous twenty-four (24) hour period is defined as one (1) calendar day.*

2. Monitoring, Recordkeeping, Exception Reporting Requirements:

45 CSR 10, §10.3. *The owner or operator of a fuel burning unit(s) which combusts natural gas, wood or distillate oil, alone or in combination, shall be exempt from the requirements of section 8.*

As such, the Mitchell Plant auxiliary boiler (auxiliary stack) is exempt from Testing, Monitoring, Recordkeeping, and Reporting requirements found in 45 CSR 10, Section 8 because the fuel burning source combusts only distillate oil. 45 CSR 10, Section 8 also contains the requirement for the development of a monitoring plan. The simple nature of burning distillate oil results in an SO2 emission rate well below the standard.

While fuel sampling and analysis may continue to be performed at this facility, it is done so at the discretion of the owner/operator and is not required by this monitoring plan for the purposes of indicating compliance with SO_2 standards.

Revisions of Monitoring Plan:

Mitchell Plant reserves the right to periodically revise the conditions of this monitoring plan. Any revised plan will become effective only after approval by the OAQ.

Implementation of Revised Monitoring Plan:

Implementation of this revised monitoring plan will occur in concurrence with the installation and operation of the new stack for Units 1 and 2 at Mitchell Plant.

Attachment L
Suggested Title V Permit Language

Wheeling Power suggests that the following changes be made to the Title V Permit Equipment Table to reflect recent additions, not impacting Title V permit language.

Emission Point ID[1]	Control Device[1]	Emission Unit ID[1]	Emission Unit Description	Design Capacity	Year Installed/ Modified
Tank #64	N/A	Tank #64	Bioreactor Nutrient Tank	12,575 Gal.	2024
Tank #65	N/A	Tank #65	Bioreactor Hydrochloric Acid Tank	6,000 Gal.	2024
Tank #66	N/A	Tank #66	WW Pond Sulfuric Acid Tank	14,500 Gal.	2023
Tank #67	N/A	Tank #67	WW Pond Sodium Hydroxide Tank	20,300 Gal.	2023
Tank #68	N/A	Tank #68	WW Pond Organosulfide Tank	6,400 Gal.	2023
Tank #69	N/A	Tank #69	WW Pond Polymer Tank	1,360 Gal.	2023

Wheeling Power suggests the following administrative revisions to the Title V permit that will improve the functionality of the permit for plant staff.

4.0 Main Boilers [Em. Unit IDs *Unit 1* and *Unit 2* – Em. Pt. IDs *1E* and *2E*]

Permit Condition 4.1.4.a: Historically, Mitchell Plant has conducted particulate matter compliance testing on both units (Unit 1 & Unit 2) during the same 7 day operational period, per the 7 day requirement listed in 45CSR2-Appendix §§ 4.1.b. Due to unit availability, scheduling and performing these tests on both units within the same 7 day period can be difficult at times, and neither 45CSR2-Appendix §§ 4.1.b. or the Title V permit specifies an individual or combined unit testing requirement within the same 7 day period. Wheeling Power is suggesting that additional language be added to this section clarifying if both units have to be tested within the same 7 day period, or if each unit has its own 7 day testing period.

6.0 Material Handling [Emission point IDs identified in Equipment Table subsection 1.1.]

Permit Condition 6.1.13: Polymer and organosulfide for the FGD wastewater treatment facility delivered to the facility via paved roadway(s) has an existing maximum annual rate of 13,500 gallons per year. Wheeling Power requests that this maximum annual rate be increased to 25,000 gallons per year to simplify the ordering and delivery process for plant staff and vendor(s).

Wheeling Power suggests the following language revisions to the Title V permit associated with the Unit 1 and Unit 2 Emergency Diesel Driven Fire Pump replacements.

7.0 Emergency Quench Water Pump Diesel-fired Engines [emission unit IDs: 6S, 7S; emission point IDs: 15E, 16E] and Emergency Diesel-Driven Fire Pumps [emission unit IDs: 17S, 18S; emission point IDs: 17E, 18E]

Sections 7.1, 7.4, and 7.5: The previous emergency diesel driven fire pump engines (17S, 18S) were subject to the requirements in 40 CFR 63 Subpart ZZZZ, and the new replacement diesel driven fire pump engines are subject to 40 CFR 63 Subpart IIII. Suggested language referring to these requirements is provided in Attachment S of this Title V Renewal Application, as Attachment I in the Minor Modification package associated with fire pump engine 18S (the Minor Modification application associated with fire pump engine 17S was previously submitted on 8/25/2023).

Attachment S
Title V Permit Revision Application

WEST VIRGINIA DEPARTMENT OF
ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY
601 57th Street, SE
Charleston, WV 25304
(304) 926-0475
www.dep.wv.gov/daq

TITLE V PERMIT REVISION APPLICATION

PLEASE CHECK TYPE OF TITLE V PERMIT REVISION:	TITLE V PERMIT NUMBER:
☐ ADMINISTRATIVE AMENDMENT ☑ MINOR MODIFICATION ☐ SIGNIFICANT MODIFICATION ☐ OFF-PERMIT CHANGE ☐ OPERATIONAL FLEXIBILITY [502(B)(10) CHANGES] ☐ REOPENING	**R30-** 05100005-2019 (MM01) WHEN DID OR WHEN WILL THE CHANGES OCCUR? MM/DD/YYYY : 06/2024 SIC CODES: PRIMARY: 4911 SECONDARY:

Refer to "Title V Revision Guidance" (Appendix A, "Title V Permit Revision Flowchart"), for type of revision, and to Section 7 of this Application for Application Completeness and Ability to Operate information

Section 1: General Information

a. Name of Applicant *(As registered with the WV Secretary of State's Office)*:	b. Facility Name or Location:
Wheeling Power Company	Mitchell Plant

b. Contact Information

Responsible Official: Joshua D. Snodgrass		Title: Plant Manager
Street or P.O. Box: P.O. Box K		
City: Moundsville	State: WV	Zip:
Telephone Number: (304) 843 - 6005	Fax Number: (304) 843 - 6080	E-mail: jdsnodgrass@aep.com
Environmental Contact: G. M. (Matt) Palmer		Title: Plant Environmental Coordinator
Street or P.O. Box: P.O. Box K		
City: Moundsville	State: WV	Zip: 26041
Telephone Number: (304) 843 - 6048	Fax Number: (304) 843 - 6080	E-mail: gmpalmer@aep.com
Application Preparer: Brandon T. Belcher		Title: Environmental Specialist
Company: AEP Service Corp.		
Street or P.O. Box: 1 Riverside Plaza, 21st Floor		
City: Columbus	State: OH	Zip: 43215
Telephone Number: (304) 541 - 7437	Fax Number: ( ) -	E-mail: btbelcher@aep.com

Person to contact if we have questions regarding this Application: Brandon T. Belcher

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Section 2: Revision Information

a. Description of Changes Associated with this Permit Revision

Provide a general description of changes to the facility.

This change involves the replacement of an emergency diesel driven fire pump and fuel tank associated with Unit 2 at the Mitchell Plant. The new diesel driven fire pump is identical to the one installed in 2023 for Unit 1.

b. Business Confidentiality Claims

Does this application include confidential information (per 45CSR31)? ☐ Yes ☑ No

If Yes, identify each segment of information on each page that is submitted as confidential, and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's ***"PRECAUTIONARY NOTICE-CLAIMS OF CONFIDENTIALITY"*** guidance as **ATTACHMENT A.**

c. Provide a **Plot Plan(s**) if new emission points were added since latest revision, e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the new/modified stationary source(s) is located as **ATTACHMENT B.** For instructions, refer to "***Plot Plan - Guidelines***"**.**

d. Provide a detailed **Process Flow Diagram(s)** if new emission points were added since latest revision, showing each new/modified process or emissions unit as **ATTACHMENT C.** Process Flow Diagrams should show all emission units, control equipment, emission points, and their relationships.

e. Emission Units Table

Fill out the **Emission Units Table** for new and/or modified equipment and provide it as **ATTACHMENT D**.

f. Emission Units Form(s)

For each new and/or modified emission unit(s) with applicable requirement(s) listed in the **Emission Units Table**, fill out and provide an **Emission Unit Form(s)** as **ATTACHMENT E**.

Are you in compliance with all facility-wide applicable requirements? ☑ Yes ☐ No

For each new and/or modified emission unit not in compliance with an applicable requirement, fill out a **Schedule of Compliance Form** as **ATTACHMENT F**.

g. Control Devices

For each new and/or modified control device listed in the **Emission Units Table**, fill out and provide an **Air Pollution Control Device Form(s)** as **ATTACHMENT G**.

For any control device that is required on an emission unit in order to meet a standard or limitation for which the potential pre-control device emissions of an applicable regulated air pollutant is greater than or equal to the Part 70 Major Source Threshold level, refer to the **Compliance Assurance Monitoring (CAM) Form(s)** for CAM applicability. If applicable, please check appropriate box in Section 3(a) below, fill out and provide these forms for each Pollutant Specific Emission Unit (PSEU) as **ATTACHMENT H**.

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Section 3: New Applicable Requirements

a. New Applicable Requirements Summary	
Mark all applicable requirements associated with the changes involved with this permit revision:	
☐ SIP	☐ FIP
☐ Minor source NSR (45CSR13)	☐ PSD (45CSR14)
☐ NESHAP (45CSR34)	☐ Nonattainment NSR (45CSR19)
☑ Section 111 NSPS (Subpart(s) IIII)	☑ Section 112(d) MACT standards (Subpart(s) ZZZZ)
☐ Section 112(g) Case-by-case MACT	☐ 112(r) RMP
☐ Section 112(i) Early reduction of HAP	☐ Consumer/commercial prod. reqts., section 183(e)
☐ Section 129 Standards/Reqts.	☐ Stratospheric ozone (Title VI)
☐ Tank vessel reqt., section 183(f)	☐ Emissions cap 45CSR§30-2.6.1
☐ NAAQS, increments or visibility (temp. sources)	☐ 45CSR27 State enforceable only rule
☐ 45CSR4 State enforceable only rule	☐ Acid Rain (Title IV, 45CSR33)
☐ Emissions Trading and Banking (45CSR28)	☐ Compliance Assurance Monitoring (40CFR64)
☐ CAIR NO_x Annual Trading Program (45CSR39)	☐ CAIR NO_x Ozone Season Trading Program (45CSR26)
☐ CAIR SO_2 Trading Program (45CSR41)	

b. Non Applicability Determinations

List all requirements, which the source has determined not applicable to this permit revision and for which a permit shield is requested. The listing shall also include the rule citation and a rationale for the determination.

N/A

☐ **Permit Shield Requested** *(not applicable to Minor Modifications, Off-Permit Changes, or for Operational Flexibility)*

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

c. Suggested Title V Draft Permit Language
Provide **Suggested Title V Draft Permit language** for the proposed Title V Permit revision (including all applicable requirements associated with the permit revision and any associated monitoring /recordkeeping/ reporting requirements), OR attach a marked up pages of current Title V Permit as **ATTACHMENT I**. Please include appropriate citations (Permit or Consent Order number, condition number and/or rule citation (e. g. 45CSR§7-4.1)) for those requirements being added / revised. See Attachment I

d. Active NSR Permits/Permit Determinations/Consent Orders Associated With This Permit Revision

Permit or Consent Order Number	Date of Issuance (MM/DD/YYYY)	Permit/Consent Order Condition Number
Installation did not trigger Reg 13 modification thresholds		

e. Inactive NSR Permits/Obsolete Permit or Consent Orders Conditions Associated With This Revision

Permit Number	Date of Issuance (MM/DD/YYYY)	Permit/Consent Order Condition Number

Section 4: Change in Potential Emissions

Pollutant	Change in Potential Emissions (+ or -), TPY	For Off-Permit Changes: Provide Total Aggregated Emissions Increase Since Last Permit/Modification
NOx	0.34	Note: The estimated emissions
CO	0.16	listed do not take into account the
NMHC	0.009	reduction in emissions related to
SO2	0.128	the replacement of the original fire
Particulate Matter	0.015	pump engine.
Provide **Supporting Emission Calculations/Estimations** as **ATTACHMENT J**.		
All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.		

Section 5: Certification of Information

a. Certification For Use Of Minor Modification Procedures *(Required Only for Minor Modification Requests)*

Note:	*This certification must be signed by a responsible official. Applications without a signed certification will be returned as incomplete. The criteria for allowing the use of Minor Modification Procedures are as follows:*

i. Proposed changes do not violate any applicable requirement;

ii. Proposed changes do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

iii. Proposed changes do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient air quality impacts, or a visibility increment analysis;

iv. Proposed changes do not seek to establish or change a permit term or condition for which there is no underlying applicable requirement and which permit or condition has been used to avoid an applicable requirement to which the source would otherwise be subject (synthetic minor). Such terms and conditions include, but are not limited to a federally enforceable emissions cap used to avoid classification as a modification under any provision of Title I or any alternative emissions limit approved pursuant to regulations promulgated under § 112(j)(5) of the Clean Air Act;

v. Proposed changes do not involve preconstruction review under Title I of the Clean Air Act or 45CSR14 and 45CSR19;

vi. Proposed changes are not required under any rule of the Director to be processed as a significant modification;

Notwithstanding subparagraph 45CSR§30-6.5.a.1.A. (items i through vi above), minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in rules of the Director which are approved by the U.S. EPA as a part of the State Implementation Plan under the Clean Air Act, or which may be otherwise provided for in the Title V operating permit issued under 45CSR30.

Pursuant to 45CSR§30-6.5.a.2.C., the proposed modification contained herein meets the criteria for use of Minor permit modification procedures as set forth in Section 45CSR§30-6.5.a.1.A. The use of Minor permit modification procedures are hereby requested for processing of this application.

(Signed):	[signature] *(Please use blue ink)*	Date:	5 / 9 / 24 *(Please use blue ink)*
Named (typed):	Joshua D. Snodgrass	Title:	Plant Manager

b. Certification of Truth, Accuracy and Completeness and Certification of Compliance ***(Required For All Revision Requests)***	
Note:	*This Certification must be signed by a responsible official. Applications without a signed certification will be returned as incomplete.*

Certification of Truth, Accuracy and Completeness

I certify that I am a responsible official (as defined at 45CSR§30-2.38) and am accordingly authorized to make this submission on behalf of the owners or operators of the source described in this document and its attachments. I certify under penalty of law that I have personally examined and am familiar with the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine and/or imprisonment.

Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

Responsible official (type or print)

Name: Joshua D. Snodgrass	Title: Plant Manager

Responsible official's signature:

Signature: [signature] *(Please use blue ink)*

Signature Date: 5/9/24 *(Please use blue ink)*

Section 6: Attachments

Note: Please check all applicable attachments included with this permit application:

☐	ATTACHMENT A: Business Confidentiality Claims
☑	ATTACHMENT B: Plot Plan(s)
☑	ATTACHMENT C: Process Flow Diagram(s)
☑	ATTACHMENT D: Emission Units Table
☑	ATTACHMENT E: Emission Unit Form(s)
☐	ATTACHMENT F: Schedule of Compliance Form(s)
☐	ATTACHMENT G: Air Pollution Control Device Form(s)
☐	ATTACHMENT H: Compliance Assurance Monitoring Form(s)
☑	ATTACHMENT I: Suggested Title V Draft Permit Language
☑	ATTACHMENT J: Supporting Emission Calculations/Estimations

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

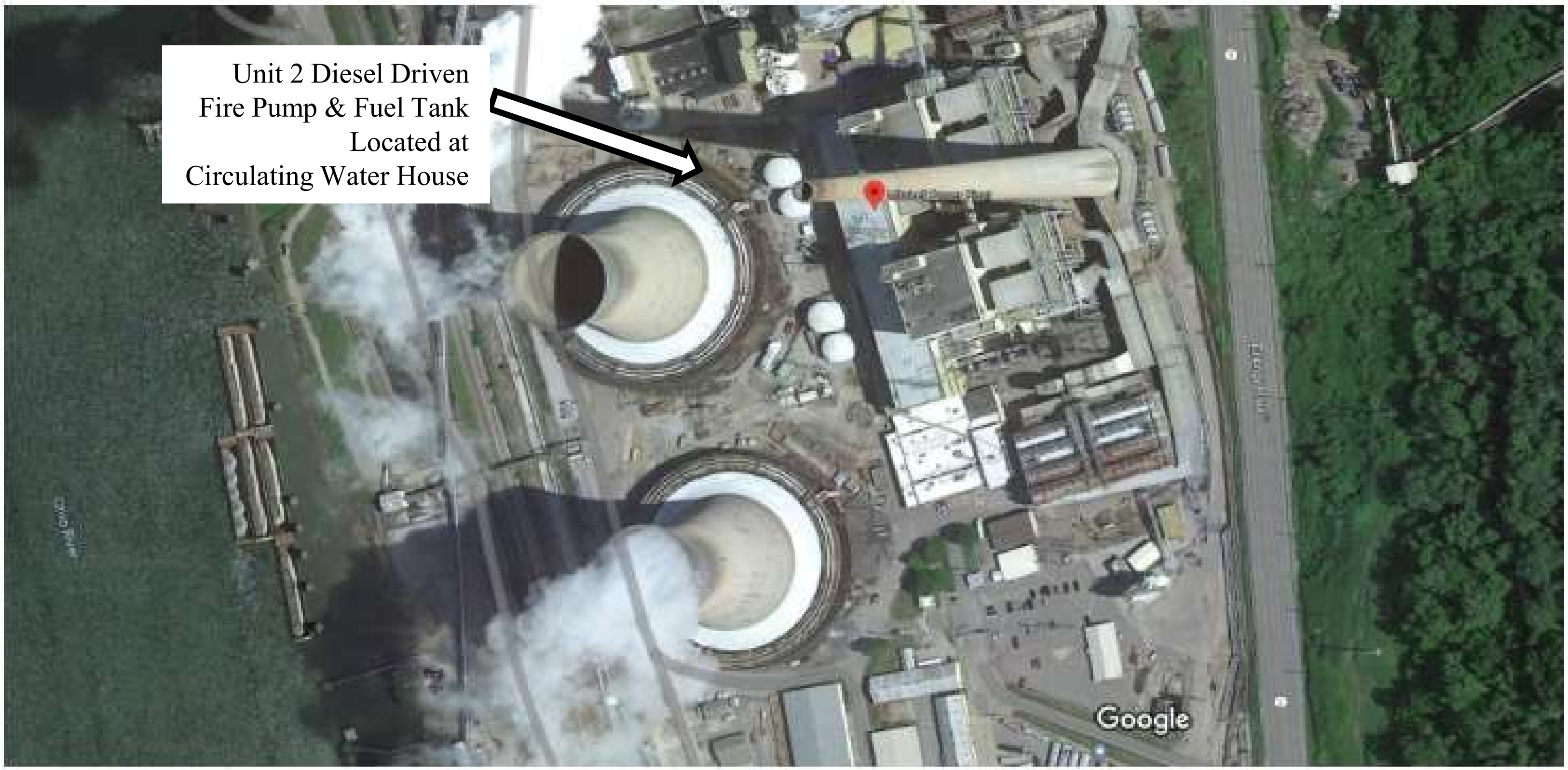
Section 7: Application Completeness and Ability to Operate information for different types of Title V Permit revisions

(Refer to "Title V Revision Guidance" for more information)

Type of Revision	Application/Notification Requirements	Ability to Operate
Administrative Amendment	☐ Description of change ☐ Supplemental information (rationale) ☐ Certification of application and compliance (Section 5(b))	Upon submittal of the application
Minor Modification	☑ Description of change ☑ Associated change in emissions ☑ Sample Calculations/estimations for determining emissions ☑ List of new applicable requirements associated with changes ☑ List of R13/R14 permits associated with the changes ☑ Suggested draft permit language ☑ Certification for use of Minor Modification (Section 5(a)) ☑ Certification of application and compliance (Section 5(b)) ***No Permit Shield***	After seven (7) days from the submittal of the application, or upon issuance of the R13/R14 permit (if any), whichever is later
Significant Modification	☐ Description of change ☐ Associated change in emissions ☐ Sample Calculations/estimations for determining emissions ☐ List of R13/R14 permits associated with the changes ☐ List of new applicable requirements associated with changes ☐ Request for permit shield ☐ Updated drawings, plot plans, process flow diagrams, etc. ☐ Certification of application and compliance (Section 5(b))	Upon issuance of the modified Title V permit (if changes either conflict with, or are prohibited by existing Title V Permit terms/ conditions), OR upon obtaining of proper R13/ R14 Permit for first 12 months (if changes neither conflict with, nor are prohibited by existing Title V Permit terms/conditions)
Off-Permit Changes	☐ Notification/application to DAQ and U.S.E.P.A. within 2 business days of the change ☐ Description of the change ☐ The date on which the change will occur or has occurred ☐ Pollutants and amounts emitted ☐ Sample Calculations/estimations for determining emissions ☐ Any new applicable requirements that will apply to changes ☐ Certification of application and compliance (Section 5(b)) ***No Permit Shield***	After two (2) days from the submittal of the application
Operational Flexibility	☐ Notification/application submitted to DAQ and U.S.E.P.A. in advance (7 days prior to making changes) ☐ Description of the change ☐ The date on which the change is to occur ☐ Permit terms and conditions affected by the change ☐ Certification of application and compliance (Section 5(b)) ***No Permit Shield***	After seven (7) days from the submittal of the application/notification to DAQ and EPA
Reopening	☐ Description of change ☐ List of new applicable requirements associated with changes ☐ Suggested draft permit language ☐ Certification of application and compliance (Section 5(b))	Ability to operate is not reflected by the changes

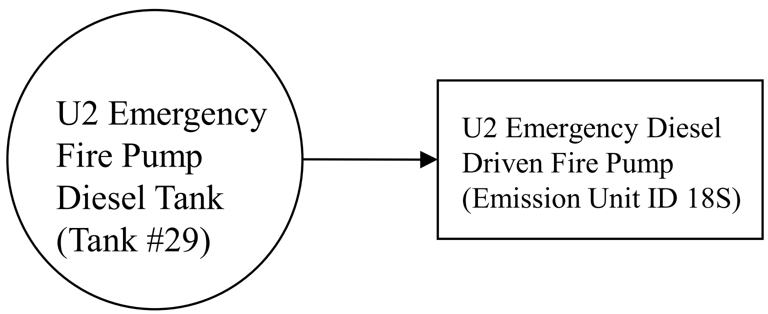
All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Attachment B: Mitchell Plant



Imagery ©2023 Airbus, Maxar Technologies, USDA/FPAC/GEO, Map data ©2023 100 ft

Attachment C:
Mitchell Plant Unit 2 Emergency Diesel Driven Fire Pump



ATTACHMENT D - Title V Equipment Table

(includes all emission units at the facility except those designated as insignificant activities in Section 4, Item 24 of the General Forms)

Emission Unit ID[1]	Emission Point ID[1]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Control Device[1]
18S	18E	Unit 2 Emergency Diesel Driven Fire Pump	2024	249 BHP	
Tank #29	Tank #29	Diesel Fire Pump Fuel Tank - U2	2024	300 gal	

[1]For 45CSR13 permitted sources, the numbering system used for the emission points, control devices, and emission units should be consistent with the numbering system used in the 45CSR13 permit. For grandfathered sources, the numbering system should be consistent with registrations or emissions inventory previously submitted to DAQ. For emission points, control devices, and emissions units which have not been previously labeled, use the following 45CSR13 numbering system: 1S, 2S, 3S,... or other appropriate description for emission units; 1C, 2C, 3C,... or other appropriate designation for control devices; 1E, 2E, 3E, ... or other appropriate designation for emission points.

ATTACHMENT E - Emission Unit Form

Emission Unit Description		
Emission unit ID number: 18S	**Emission unit name:** Unit 2 Emergency Diesel Driven Fire Pump	**List any control devices associated with this emission unit:** N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Emergency diesel driven fire pump that will replace existing unit associated with Unit 2 at the plant. 249 BHP diesel engine.

Manufacturer: Cummins	**Model number:** CFP7E-F60 Fire Pump / QSB6.7 Engine	**Serial number:**
Construction date: MM/DD/YYYY 06/2024	**Installation date:** MM/DD/YYYY 06/2024	**Modification date(s):** MM/DD/YYYY 06/2024

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Approx. 14 gal/hr, 249 BHP

Maximum Hourly Throughput: Approx. 14 gal/hr	**Maximum Annual Throughput:** 7,000 gal/yr	**Maximum Operating Schedule:** Assumed 500 hr/yr, but not limited during emergency

***Fuel Usage Data* (fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☑ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 249 BHP	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel, less than 15 ppm sulfur.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel Fuel	15 ppm		Approx. 137,030 btu/gal

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Emissions Data

Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.65	0.16
Nitrogen Oxides (NO_X)	1.36	0.34
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.06	0.015
Particulate Matter (PM_{10})	0.06	0.015
Total Particulate Matter (TSP)	0.06	0.015
Sulfur Dioxide (SO_2)	0.51	0.128
Volatile Organic Compounds (VOC)	0.63	0.16
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY
CO2	286.35	71.59

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Manufacturer's Data used for NOx, PM, and CO. AP-42 used for SO2, CO2, and VOC.

Applicable Requirements
List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included. This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Section 7.1.
☐ Permit Shield
For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.) This emergency diesel fire pump engine is subject to the requirements in 40 CFR 63 Subpart IIII. The previous diesel fire pump engine was subject to the requirements in 40 CFR 63 Subpart ZZZZ and suggested language revisions have been included in Attachment L. Requirements currently captured in Title V permit: R30-05100005-2019 (MM01) Sections 7.2 through 7.5.
Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Attachment I

Summary of Requirements[1]

40 CFR part 60, subpart IIII

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

For fire pump engines with a displacement of less than 30 liters/cyl,
manufactured during or after the model year that applies to your fire pump engine power rating
in Table 3 of 40 CFR part 60, subpart IIII.

NOTE: To refer directly to the regulatory text, please go to Subpart IIII (scroll down to almost the end of the page).

Temporary Engines:

Per 60.4200(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

Emission Standards: 60.4205(c), Table 4

60.4205(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

Per 60.4215(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205. Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the emission standards in 60.4215(c).

Special requirements apply to engines used in Alaska. Please refer to 60.4216 for the specific requirements and provisions that apply to engines that are located in areas of Alaska not accessible by the FAHS.

[1]Disclaimer: The content provided in this software tool is intended solely as assistance for potential reporters to aid in assessing requirements for compliance under the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60 Subpart IIII. Any variation between the rule and the information provided in this tool is unintentional, and, in the case of such variations, the requirements of the rule govern. Use of this tool does not constitute an assessment by EPA of the applicability of the rule to any particular facility. In any particular case, EPA will make its assessment by applying the law and regulations to the specific facts of the case.

Fuel Requirements: 60.4207(a), (b), (e)

60.4207(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Per 60.4215(b) stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in 40 CFR 60.4207.

Special requirements apply to engines used in Alaska. Please refer to 60.4216 for the specific requirements and provisions that apply to engines that are located in areas of Alaska not accessible by the FAHS.

Per 60.4217 Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

Importing/Installing Requirements: 60.4208(h), (i)

60.4208(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

Monitoring Requirements: 60.4209(a); If your engine is equipped with a diesel particulate filter: 60.4209(b)

60.4209(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

If your engine is equipped with a diesel particulate filter: 60.4209(b)

60.4209 (b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements: 60.4206, 60.4211(a), (c), (f), (g)

60.4206 Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

60.4211(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(f) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

Testing Requirements: 60.4212

60.4212 Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

Notification, Reports, and Records Requirements: 60.4214(b); If equipped with DPF: 60.4214(c); If >100 HP and > 15 hrs/yr for emergency DR: 60.4214(d)

60.4214(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in Table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

If your engine is equipped with a diesel particulate filter: 60.4214(c)

60.4214(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

If your engine is greater than 100 HP and used more than 15 hours a year for emergency demand response:

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

General Provisions (40 CFR part 60): Table 8

Attachment J:

Cummins QSB6.7 Emergency Diesel Driven Fire Pump Emission Calculations

Max Power	249 BHP			
Fuel Use:	14 gal/hr		1.92	MMBtu/hr
	7,000 gal/yr assuming 500 hours operation.		959.21	MMBtu/yr
	137,030 Btu/gal (diesel heat content)			

Hourly Emissions:

	Emission Factor*	Emissions	Emissions	Note:
	Grams/kWh	lb/hr	lb/24hr	
NOx	2.475 Grams/bhp-hr	1.36	32.61	
CO	1.193 Grams/bhp-hr	0.65	15.72	
NMHC	0.062 Grams/bhp-hr	0.03	0.82	* NOx, CO, and NMHC EF's based on Cummins QSB6.7 Spec Sheet.
SO2	0.00205 lb/HP-hr	0.51	12.25	* SO2 estimated using Chapter 3.3 of AP-42 for diesel industrial engines.
PM=PM10=PM2.5	0.111 Grams/bhp-hr	0.06	1.46	* All PM assumed to be less than 1 um
CO2	1.15 lb/HP-hr	286.35	6872.40	* CO2 estimated using AP-42 CO2 EF for diesel industrial engines.
VOC (used TOC)	0.0025141 lb/HP-hr	0.63	15.02	*TOC estimated using AP-42 TOC EF's for exhaust and crankcase emissions for diesel industrial engines.
Formaldehyde	0.00118 lb/MMBtu	0.00226	0.0543	* Formaldehyde estimated using AP-42 Formaldehyde EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Benzene	0.000933 lb/MMBtu	0.0018	0.043	* Benzene estimated using AP-42 Benzene EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Propylene	0.00258 lb/MMBtu	0.005	0.12	* Propylene estimated using AP-42 1,3 Butadiene EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Toluene	0.000409 lb/MMBtu	0.0008	0.019	* Toluene estimated using AP-42 Toluene EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Xylenes	0.000285 lb/MMBtu	0.00055	0.013	* Xylenes estimated using AP-42 Xylenes EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).

Acetaldehyde	0.000767 lb/MMBtu	0.00147	0.0353	*Acetaldehyde estimated using AP-42 Acetaldehyde EF for diesel industrial engines. Assuming 14 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Acrolein	0.0000925 lb/MMBtu	0.000177	0.00426	*Acrolein estimated using AP-42 Acrolein EF for diesel industrial engines. Assuming 1.4gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Napthalene	0.0000848lb/MMBtu	0.00016	0.004	*Naphthalene estimated using AP-42 Naphthalene EF for diesel industrial engines. Assuming 1.9 gal/hr and 137,030 Btu/gal (therefore 1.92 MMBtu/hr).
Total HAPS		0.007	0.17	

Typical Annual Emissions - **(Assume 500 hrs/yr)**

	Emissions
	tons/yr
NOx	0.34
CO	0.16
HC	0.009
SO2	0.1276
PM	0.015
CO2	71.59
VOC	0.16
Formaldehyde	0.000566
Benzene	0.00045
Propylene	0.0012
Toluene	0.00020
Xylenes	0.00014
Acetaldehyde	0.000368
Acrolein	0.0000444
Napthalene	0.00004
Total HAPS	0.0028