

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.)

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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

Mitchell Plant Title V Renewal
R30-05100005-2019 (MM01) Renewal
2024

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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	4
2.0.	General Conditions.....	8
2.1.	Definitions	8
2.2.	Acronyms	8
2.3.	Authority	9
2.4.	Term and Renewal.....	9
2.5.	Duty to Comply	9
2.6.	Duty to Provide Information.....	9
2.7.	Duty to Supplement and Correct Information	10
2.8.	Administrative Update.....	10
2.9.	Permit Modification.....	10
2.10.	Major Permit Modification	10
2.11.	Inspection and Entry	10
2.12.	Emergency.....	10
2.13.	Need to Halt or Reduce Activity Not a Defense.....	11
2.14.	Suspension of Activities	11
2.15.	Property Rights.....	11
2.16.	Severability.....	12
2.17.	Transferability	12
2.18.	Notification Requirements.....	12
2.19.	Credible Evidence	12
3.0.	Facility-Wide Requirements.....	13
3.1.	Limitations and Standards	13
3.2.	Monitoring Requirements.....	13
3.3.	Testing Requirements	13
3.4.	Recordkeeping Requirements.....	14
3.5.	Reporting Requirements	15
4.0.	Source-Specific Requirements.....	17
4.1.	Limitations and Standards	17
4.2.	Monitoring Requirements.....	19
4.3.	Testing Requirements	20
4.4.	Recordkeeping Requirements.....	20
5.0.	Source-Specific Requirements for the Auxiliary Boiler (Aux-1).....	22
5.1.	Limitations and Standards	22
5.2.	Monitoring Requirements.....	24
5.3.	Testing Requirements	24
5.4.	Recordkeeping Requirements.....	25
5.5.	Reporting Requirements	26
	CERTIFICATION OF DATA ACCURACY.....	27

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

Page 5 of 27

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				

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

Page 6 of 27

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	

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

Page 7 of 27

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	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	PM₁₀	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	SO₂	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	Not Applicable	VOL	Volatile Organic Liquids
NAAQS	National Ambient Air Quality Standards		
NESHAPS	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

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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.

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

- 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 SO₃ 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

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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.

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

- 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 SO₃ 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:

<u>Pollutant</u>	<u>USEPA Test Method*</u>
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:
- The date, place as defined in this permit, and time of sampling or measurements;
 - The date(s) analyses were performed;
 - The company or entity that performed the analyses;
 - The analytical techniques or methods used;
 - The results of the analyses; and
 - 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:
- The equipment involved.
 - Steps taken to minimize emissions during the event.

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

- 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.

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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 ₂ O	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 SO₂ 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

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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.]

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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]

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

5.4. Recordkeeping Requirements

- 5.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:
- The date, place as defined in this permit, and time of sampling or measurements;
 - The date(s) analyses were performed;
 - The company or entity that performed the analyses;
 - The analytical techniques or methods used;
 - The results of the analyses; and
 - 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:
- The equipment involved.
 - Steps taken to minimize emissions during the event.
 - The duration of the event.
 - The estimated increase in emissions during the event.
- For each such case associated with an equipment malfunction, the additional information shall also be recorded:
- The cause of the malfunction.
 - Steps taken to correct the malfunction.
 - 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:
- 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.]

Permit R13-2608E
AEP Generation Resources, Inc. • Mitchell Plant

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.

Signature¹

(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. SO₂ 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 -0500

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
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2. SO₂ 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
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2. SO₂ 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.



For more information, see instructions and 40 CFR 72.30 and 72.31.

STEP 1

Mitchell (WV) Facility (Source) Name	West Virginia State	3948 Plant Code
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Enter the unit ID# for every affected unit at the affected source in column "a."

EPA Form 7610-16 (Revised 8-2019)

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)

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 	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.

Mitchell	WV	3948
Plant Name	State	Plant Code

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 <u>Phase I</u> dry bottom wall-fired boilers)	X	X				
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for <u>Phase I</u> tangentially fired boilers)						
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for <u>Phase II</u> dry bottom wall-fired boilers)						
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for <u>Phase II</u> 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)						

NO_x Compliance – Page 2

STEP 2, cont'd

Mitchell Plant Name (From Step 1)

	ID#	ID#	ID#	ID#	ID#	ID#
	Type	Type	Type	Type	Type	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, <u>2019</u>

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 <i>Scott A. Weaver</i>	Date <i>12-18-18</i>

West Virginia Department of Environmental Protection
Joe Manchin, III **Division of Air Quality** *Randy C. Huffman*
Governor 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

A blue ink signature of William F. Durham, written in a cursive style, is positioned above a horizontal line.

William F. Durham
Director

Issued: August 8, 2014

Class II General Permit G60-C
Emergency Generator

Page 2 of 3

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.

Class II General Permit G60-C
Emergency Generator

Page 3 of 3

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.*

A handwritten signature in blue ink, appearing to read "William F. Durham", is written over a horizontal line.

*William F. Durham
Director, Division of Air Quality*

Issued: May 9, 2018

G60-D
Emergency Generator

2 of 19

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.....	4
1.1.	General Permit Registration	4
2.0.	General Conditions.....	4
2.1.	Purpose	4
2.2.	Authority	4
2.3.	Applicability	4
2.4.	Definitions	5
2.5.	Acronyms	5
2.6.	Permit Expiration and Renewal	6
2.7.	Administrative Update to General Permit Registration	6
2.8.	Modification to General Permit Registration.....	6
2.9.	Duty to Comply	6
2.10.	Inspection and Entry	7
2.11.	Need to Halt or Reduce Activity not a Defense.....	7
2.12.	Emergency.....	7
2.13.	Federally-Enforceable Requirements	8
2.14.	Duty to Provide Information.....	8
2.15.	Duty to Supplement and Correct Information	8
2.16.	Credible Evidence	8
2.17.	Severability.....	8
2.18.	Property Rights.....	8
2.19.	Notification Requirements.....	9
2.20.	Suspension of Activities	9
2.21.	Transferability	9
3.0.	Facility-Wide Requirements	10
3.1.	Siting Criteria	10
3.2.	Limitations and Standards	10
3.3.	Monitoring Requirements.....	11
3.4.	Testing Requirements	11
3.5.	Recordkeeping Requirements.....	12
3.6.	Reporting Requirements	12
4.0.	Source-Specific Requirements	14
4.1.	Limitations and Standards	14
4.2.	Recordkeeping Requirements.....	14
5.0.	Source-Specific Requirements [Reciprocating Internal Combustion Engine(s) (RICE)]	16
5.1.	Limitations and Standards	16
5.2.	Monitoring Requirements.....	17
5.3.	Recordkeeping Requirements.....	17
5.4.	Testing Requirements	18
5.5.	Reporting Requirements	18
6.0.	Source-Specific Requirements (Tanks).....	18
6.1.	Limitations and Standards	18
6.2.	Monitoring Requirements.....	18
6.3.	Testing Requirements	18
6.4.	Recordkeeping Requirements.....	18
6.5.	Reporting Requirements	18
	CERTIFICATION OF DATA ACCURACY.....	19

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

G60-D
Emergency Generator

5 of 19

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 H₂S 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	PM	Particulate Matter
CFR	Code of Federal Regulations	PM _{2.5}	Particulate Matter less than 2.5 µm in diameter
CO	Carbon Monoxide	PM ₁₀	Particulate Matter less than 10 µm in diameter
CSR	Code of State Rules	ppm	Parts per million
DAQ	Division of Air Quality	ppm _v	Parts per million by Volume
DEP	Department of Environmental Protection	PSD	Prevention of Significant Deterioration
FOIA	Freedom of Information Act	psi	Pounds per square inch
HAP	Hazardous Air Pollutant	RICE	Reciprocating Internal Combustion Engine
HP	Horsepower	SCR	Selective Catalytic Reduction
lb/hr	Pounds per hour	SIC	Standard Industrial Classification
LDAR	Leak Detection and Repair	SIP	State Implementation Plan
M or m	Thousand	SO ₂	Sulfur Dioxide
MACT	Maximum Achievable Control Technology	TAP	Toxic Air Pollutant
MDHI	Maximum Design Heat Input	TPY	Tons per year
MM or mm	Million		
MMBTU/hr	Million British Thermal Units Per Hour		
MMCF/hr	Million Cubic Feet per Hour		

G60-D
Emergency Generator

6 of 19

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
LAT	Latitude	VEE	Visual Emissions Evaluation
LON	Longitude	VOC	Volatile Organic Compounds
		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

G60-D
Emergency Generator

7 of 19

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.

G60-D
Emergency Generator

9 of 19

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

G60-D
Emergency Generator

12 of 19

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

G60-D
Emergency Generator

13 of 19

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.

G60-D
Emergency Generator

14 of 19

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.

G60-D
Emergency Generator

15 of 19

- 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 ppmv.
 - 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.

G60-D
Emergency Generator

18 of 19

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.

G60-D
Emergency Generator

19 of 19

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.

Signature¹

(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 principal¹³ business function, or any other person who performs similar policy or decision-making¹⁴ 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. 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 (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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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

Mitchell Plant Title V Renewal
R30-05100005-2019 (MM01) Renewal
2024

Suggested Language - Title V Operating Permit R30-05100005
Wheeling Power Co. • Mitchell Plant

Page 1

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).

Suggested Language - Title V Operating Permit R30-05100005
Wheeling Power Co. • Mitchell Plant

Page 2

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

Mitchell Plant Title V Renewal
R30-05100005-2019 (MM01) Renewal
2024

	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	
	<i>TITLE V PERMIT REVISION APPLICATION</i>	
PLEASE CHECK TYPE OF TITLE V PERMIT REVISION: ☐ ADMINISTRATIVE AMENDMENT ☒ MINOR MODIFICATION ☐ SIGNIFICANT MODIFICATION ☐ OFF-PERMIT CHANGE ☐ OPERATIONAL FLEXIBILITY [502(B)(10) CHANGES] ☐ REOPENING		TITLE V PERMIT NUMBER: R30- 05100005-2019 (MM01) WHEN DID OR WHEN WILL THE CHANGES OCCUR? MM/DD/YYYY : 06/2024 SIC CODES: PRIMARY: 4911 SECONDARY:
<i>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</i>		

Section 1: General Information

a. Name of Applicant (As registered with the WV Secretary of State's Office): Wheeling Power Company	b. Facility Name or Location: Mitchell Plant
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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.
<i>All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.</i>

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) <u> </u>)	☒ Section 112(d) MACT standards (Subpart(s) <u> </u>)
☐ 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 <i>(not applicable to Minor Modifications, Off-Permit Changes, or for Operational Flexibility)</i>	
<i>All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.</i>	

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 listed do not take into account the reduction in emissions related to the replacement of the original fire pump engine.
CO	0.16	
NMHC	0.009	
SO2	0.128	
Particulate Matter	0.015	

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):

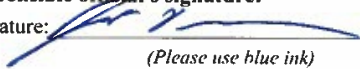

(Please use blue ink)

Date: 5 / 9 / 24

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:	<i>This Certification must be signed by a responsible official. Applications without a signed certification will be returned as incomplete.</i>
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)

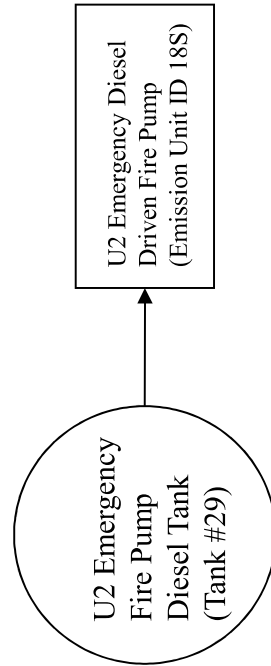
Type of Revision	Application/Notification Requirements	Ability to Operate
Administrative Amendment	☐ Description of change ☐ Supplemental information (rationale) ☐ Certification of application and compliance (Section 5(b))	Upon submittal of the application
Minor Modification	☒ Description of change ☒ 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



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)

[illegible]

¹For 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			
<i>Emission Unit Description</i>			
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
CO ₂	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 NO_x, 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 Requirements¹

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.

¹Disclaimer: 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), (c)

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.

(c) 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:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad (\text{Eq. 1})$$

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 lb/hr	Emissions lb/24hr	Note:
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

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

Laura M. Crowder
Director, Division of Air Quality
Laura M. Crowder

Digitally signed by: Laura M. Crowder
DN: CN = Laura M. Crowder email = Laura M.
Crowder@wv.gov C = US O = WV DEP OU = DAQ
Date: 2025.05.09 14:15:47 -04'00'

Issued: May 9, 2025 • Effective: May 23, 2025
Expiration: May 9, 2030 • Renewal Application Due: November 9, 2029

Permit Number: **R30-05100005-2025**
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	3
2.0	General Conditions	13
3.0	Facility-Wide Requirements and Permit Shield.....	21

Source-specific Requirements

4.0	Main Boilers	30
5.0	Auxiliary Boilers	54
6.0	Material Handling	61
7.0	Emergency Quench Water Pump Diesel-Fired Engines.....	67
8.0	Liquid Propane Vapor Engine Driven Emergency Generator, Black Start Emergency Generators, Diesel Fuel Storage Tank, Diesel-Fired Emergency Generators and Diesel-Fired Emergency Fire Pump Engines.....	71
9.0	Landfill Building Furnace CB-325.....	87

APPENDIX A – 45CSR2 & 45CSR10 Monitoring Plans

APPENDIX B – Certification of Data Accuracy

APPENDIX C – DAQ Letter Dated September 3, 2002 regarding Thermal Decomposition of Boiler Cleaning Solution

APPENDIX D – DAQ Letter Dated January 21, 2004 regarding Demineralizer Resin Burn

APPENDIX E – Cross-State Air Pollution Rule (CSAPR) Requirements

APPENDIX F – Acid Rain Permit

APPENDIX G – Class II General Permit Registration G60-C057A

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

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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-1 (Fugitive)	Limestone Weigh Feeder (one per silo)	2007	68.4 TPH	FE
LSWF-2	LSWF-2 (Fugitive)				
LSWF-3	LSWF-3 (Fugitive)				
	(Fugitive)	Wet Ball Mill (one per silo)	2007	68.4 TPH	FE

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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
11S – Wastewater Treatment Material Handling					
	Fugitive	Truck Unloading Connection (2)	2007	25 TPH	FE
	24E	Lime Storage Silo #1	2007	100 TPH	BH, FE
	25E	Lime Storage Silo #2	2007	100 TPH	BH, FE
	Fugitive	Wastewater Treatment Cake Stockpile	2007	3,600 Tons	Building Enclosure
FB-2	Fugitive	Filter Cake Feeder/Breaker	2007	600 TPH	PE
BC-22	Fugitive	Transfer Conveyor 22	2007	600 TPH	PE
TH-12	Fugitive	Transfer House #12	2007	600 TPH	PE
Tank #1	Tank #1	Ignition Oil Tank – S. of U1 Cooling Tower	~1975	1,500,000 gallons	N/A
Tank #2	Tank #2	Ignition Oil Tank – N. of U2 Cooling Tower	1971	500,000 gallons	N/A
Tank #3	Tank #3	Ignition Oil Tank – N. of U2 Cooling Tower	1971	500,000 gallons	N/A
Tank #5	Tank #5	Used Oil Tank – Tractor Shed	~2000	500 gallons	N/A
Tank #6	Tank #6	Sulfuric Acid Tank – W. of Units 1&2	1971	15,000 gallons	N/A
Tank #7	Tank #7	Ammonium Hydroxide Tank – W. of Units 1&2	1971	4,750 gallons	N/A
Tank #11	Tank #11	No.2 Fuel Oil Tank – Coal Transfer Station #3	2007	1,000 gallons	N/A
Tank #12	Tank #12	No.2 Fuel Oil Tank – Coal Transfer Station R-2	~2004	3,000 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.

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
Tank #13	Tank #13	No.2 Fuel Oil Tank – Coal Transfer Station R-4	~2004	3,000 gallons	N/A
Tank #14	Tank #14	No.2 Fuel Oil Tank – Drain Receiver Tank	1969	400 gallons	N/A
Tank #15	Tank #15	Gasoline Tank – Main Plant Entrance	1991	8,000 gallons	N/A
Tank #16	Tank #16	Diesel Fuel Tank – Tractor Shed	2014	10,000 gallons	N/A
Tank #17	Tank #17	Turbine Oil Tank – U1	1971	~14,000 gallons	N/A
Tank #18	Tank #18	Turbine Oil Tank – U2	1971	~14,000 gallons	N/A
Tank #19	Tank #19	Lube Oil Tank – U1	1971	~20,000 gallons	N/A
Tank #20	Tank #20	Lube Oil Tank – U2	1971	~18,000 Gal.	N/A
Tank #21	Tank #21	Chemical Cleaning Solution Tank	1989	1,000,000 gallons	N/A
Tank #22	Tank #22	EHC System Oil Tank – U1	1971	200 gallons	N/A
Tank #23	Tank #23	New Lube Oil Tank – U1	1971	1,000 gallons	N/A
Tank #24	Tank #24	Used Oil Bulk Tank – U0	~2002	275 gallons	N/A
Tank #25	Tank #25	EHC System Oil Tank – U2	1971	625 gallons	N/A
Tank #26	Tank #26	New Lube Oil Tank – U2	1971	1,000 gallons	N/A
Tank #27	Tank #27	Used Oil Bulk Tank – U2	~2002	275 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

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed ¹	Design Capacity ²	Control Device ³
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

¹ "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

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	NSPS	New Source Performance
CBI	Confidential Business Information		Standards
CEM	Continuous Emission Monitor	PM	Particulate Matter
CES	Certified Emission Statement	PM₁₀	Particulate Matter less than
C.F.R. or CFR	Code of Federal Regulations		10µm in diameter
CO	Carbon Monoxide	pph	Pounds per Hour
C.S.R. or CSR	Codes of State Rules	ppm	Parts per Million
DAQ	Division of Air Quality	PSD	Prevention of Significant
DEP	Department of Environmental		Deterioration
	Protection	psi	Pounds per Square Inch
FOIA	Freedom of Information Act	SIC	Standard Industrial
HAP	Hazardous Air Pollutant		Classification
HON	Hazardous Organic NESHAP	SIP	State Implementation Plan
HP	Horsepower	SO₂	Sulfur Dioxide
lbs/hr or lb/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	TSP	Total Suspended Particulate
	Technology	USEPA	United States
mm	Million		Environmental Protection
mmBtu/hr	Million British Thermal Units per		Agency
	Hour	UTM	Universal Transverse
mmft³/hr or	Million Cubic Feet Burned per		Mercator
mmcf/hr	Hour	VEE	Visual Emissions
NA or N/A	Not Applicable		Evaluation
NAAQS	National Ambient Air Quality	VOC	Volatile Organic
	Standards		Compounds
NESHAPS	National Emissions Standards for		
	Hazardous Air Pollutants		
NO_x	Nitrogen Oxides		

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§30-5.6.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§30-5.1.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 SO₂ 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 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, 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 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 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 §§ 22-5-4(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 Enforcement¹:

DEPAirQualityReports@wv.gov

¹For 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:
DEPAirQualityReports@wv.gov

US EPA:
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§5-2.5. 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. Reserved

- 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. Reserved.

- 4.1.4. a. The combined particulate matter emissions from Unit 1 & 2 stacks shall not exceed 702 lb/hr. The result of each compliance test is to be the arithmetic average of 3 complete sampling runs conducted within a 7 day period for both Unit 1 & 2 stacks. A complete sampling run shall be one complete determination of the total particulate matter emission rate through the test stack for which the minimum total sampling time is 2 hours and the minimum total sample volume is 60 cubic feet adjusted to 68°F and 29.92 inches of Hg. Smaller sampling volumes and shorter sampling times may be approved by the Secretary on a case-by-case basis when necessitated by process variables or other factors.

[45CSR§2-4.1.1.; 45CSR2-Appendix §§ 4.1.2. & 4.1.3.]

- b. **Filterable Particulate Matter (PM) Emission Limitation for 40 C.F.R. 63 Subpart UUUUU.** Before July 6, 2027, 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 SO₂ on a 3-hour block average basis, with SO₂ mass emissions not to exceed an average of 20,485.2 lb SO₂/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 3.1.2.]
- b. **Sulfur Dioxide (SO₂) 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 (SO₂), you must meet the emission limit 0.20 lb/MMBtu, using SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 permit 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 SO₃ 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 permit 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 O₂ 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 O₂ 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 tune-up date electronically, in accordance with §63.10031(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 permit 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)). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i).

- 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 §§63.10021(h) and 63.10032 (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. For shutdown periods that occur on or after January 1, 2024, you must report the applicable information concerning shutdown periods quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

[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.

[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., 8.1.1. & 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 SO₂, and NO_x, emissions from emission points *1E* and *2E* as specified in 40 C.F.R. Part 75 and measure CO₂ 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 SO₂ alternate limit for acid gases, and corresponding monitoring requirements in permit 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§§2-8.3.3., 8.4.1. & 8.4.1.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, SO₂, 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] (SO₂ 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 (O₂) or carbon dioxide (CO₂) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O₂ or CO₂ concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O₂ or CO₂ data in the emissions calculations; do not use part 75 substitute data values.

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.

SO₂ CEMS Requirements for 40 C.F.R. 63 Subpart UUUUU.

- (1) If you use an SO₂ 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 SO₂ 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 SO₂ CEMS has a span value of 30 ppm or less.
- (3) Calculate and record a 30-boiler operating day rolling average SO₂ 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 SO₂ emission rates in the 30 boiler operating day period.
- (4) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ 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 SO₂ 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 SO₂ 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 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] (*SO₂ 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] (*SO₂ CEMS and Hg Sorbent Trap Monitoring System*)

4.2.15. 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 excluding zero and span 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] (*SO₂ 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 SO₂, 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, CO₂, O₂, 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] (*SO₂ 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 June 7, 2027.

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

Test	Test Results	Retesting Frequency
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. 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 (CO₂ or O₂) 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 CO₂ (or O₂) 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 CO₂ or O₂ 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 SO₂ 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 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§2-8.3.1.]

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§2-8.3.3.]

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 (permit 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 permit 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 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 copy of each notification or report that you submitted submit to comply with this subpart. You must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you 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 [permit](#) 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 (permit 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 permit 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 SO₂, NO_x, and CO₂ 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§2-8.3.2.]

- 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§2-9.3.1.]

- 4.5.4. Except as provided in permit condition 4.5.3. above, the owner or operator shall report to the Secretary by telephone 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§2-9.3.2.]

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 applicable reports and notifications required under ~~40 CFR~~ 63.10031 (a) through (k) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS

Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved.

[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 §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you 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 (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 permit 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) (permit condition 4.5.12.).
- d. Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in paragraph (c) of this section must include the excess emissions and monitor downtime summary report described in 40 CFR 63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR 63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and you must, instead, include in the quarterly compliance reports described in paragraph (g) of this section the applicable data elements in section 13 of appendix E to this subpart for any "deviation" (as defined in 40 CFR 63.10042 and elsewhere in this subpart) that occurred during the calendar quarter. If there were no deviations, you must include a statement to that effect in the quarterly compliance report.
- e. Starting with a report for the first calendar quarter of 2024, you must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of appendix E to this subpart. For each stack test summarized in the compliance report, you must also submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter.

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

- (1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)) 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 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)).
- (2) The first compliance report must be 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 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)).
- (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 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 permit condition.
- (6) The final semiannual compliance report shall cover the reporting period from July 1, 2023, through December 31, 2023. Quarterly compliance reports shall be submitted thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024.

[40 C.F.R. §§63.10031(b)(1) through (6); 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 permit condition 3.5.6. If an affected source submits a semiannual compliance report pursuant to paragraphs (c) and (d) in permit condition 4.5.10., or two quarterly compliance reports covering the appropriate calendar half pursuant to paragraph (g) of this section, along with, or as part of, the semiannual monitoring report required by permit condition 3.5.6., and the compliance report(s) 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(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) 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. For each performance stack test completed on or after January 1, 2024, in accordance with 40 CFR 63.10031(g), submit the applicable reference method information in sections 17 through 31 of appendix E to 40 C.F.R. 63 Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed.

[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 MLI*]

5.1. Limitations and Standards

5.1.1. Reserved

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 ₂ O	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 SO₂).

² Compliance with this PM limitation ensures compliance with the 45CSR§2-4.1.2. limit of 59.67 lb/hr.
[45CSR§2-4.1.2.; 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 permit condition.
[40 C.F.R. §60.44b(c); 45CSR16; 40 C.F.R. §63.7575; 45CSR34; 45CSR§2-8.4.1.a.]

d. For the purpose of complying with the SO₂ limits in item a of this permit 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(i)(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.
[45CSR§§2-3.1.]

[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 permit condition) to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (i) of this permit 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 permit 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 MLI* 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 MLI*) 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§§2-8.3.3., 8.4.1. and 8.4.1.a.]
- 5.2.3. In order to determine compliance with permit 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 permit condition 5.1.3. Such records shall be maintained in accordance with permit condition 3.4.2.
[45CSR13, R13-2608, 5.2.1.; 40 C.F.R. §60.49b(d)(2); 45CSR16; 45CSR§2-8.3.3.; 45CSR§§10-8.2.3.c. and 8.3.3.]
- 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 permit condition 5.1.3. from the fuel supplier. Such records shall be maintained in accordance with permit condition 3.4.2. **[45CSR13, R13-2608, 5.2.2.; 40 C.F.R. §60.49b(r)(1); 45CSR16; 45CSR§10-8.2.3.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 permit condition 3.4.2.

[45CSR13, R13-2608, 5.2.3.; 40 C.F.R. §§60.48b(a) and 60.49b(f); 45CSR16; 45CSR§2-8.1.1.]

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§2-8.3.1.]

- 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§2-8.3.3.]

- 5.4.3. You must keep records according to paragraphs (1), (2), and (3) of this permit 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§2-8.3.2.]

- 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§2-9.3.1.]

- 5.5.3. Except as provided in permit condition 5.5.2. above, the owner or operator shall report to the Secretary by telephone 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§2-9.3.2.]

- 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 (permit 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 (permit 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 (permit 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 (permit 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 (permit 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 permit 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 permit condition 5.2.5. that indicate visible emissions in excess of either items e and/or f of permit 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 permit 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§2-8.3.2.]**

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 SO₃ 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 (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 SO₃ 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 permit 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 RICE¹, you must meet the following requirements, except during periods of startup:

- a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;²
- b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first, and replace as necessary;
- c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous change, 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 permit 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 permit condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this permit 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 permit condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this permit 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 permit 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.

[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:

- In accordance with the manufacturer's recommendations and specifications or in accordance with a site-specific maintenance plan; and,
- 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 III, JJJ 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 III – 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 permit 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+NO _x (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.

NMHC+NO _x (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
4.0	3.5	0.20

[40 C.F.R. §§ 60.4205(c); 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 (permit 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 permit 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 permit 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 permit condition 8.1.5.c., you must comply by purchasing an engine certified to the emission standards in permit 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 permit 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 permit 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 permit condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this permit 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 permit condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this permit 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 permit condition. Except as provided in paragraph (3)(i) of this permit 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 (permit 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 permit 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 permit condition, is prohibited. If you do not operate the engine according to the requirements in paragraphs (1) through (3) of this permit 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 permit condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (3) of this permit 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 permit condition. Except as provided in paragraph (3)(i) of this permit 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 permit conditions 8.4.1. and 8.4.2. shall be maintained in accordance with permit 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) (permit condition 8.1.10.), you must demonstrate compliance according to the method specified in paragraph (1) of this permit 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, permit 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 permit 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) (permit 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 permit 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.
 - (v) 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 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 permit 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 permit 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
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(2) of this permit 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 40 C.F.R. §60.4245(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 permit 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 permit 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 40 C.F.R. §60.4214(g).

[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 permit 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 permit 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 permit 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 permit 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 permit 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 permit 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 permit 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 permit 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 (PSI). COMS meeting the requirements of 40 CFR Part 75 (Acid Rain) will be deemed to have satisfied the requirements of PSI.*

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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 Company	Opacity	American Electric Power		
		Philip Sporn Plant		
Emission 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: OPAC5QA

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

Appendix B
Sample

* = 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.

Signature¹ _____
(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, DWW



West Virginia Department
of Environmental Protection

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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
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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 SO₂ 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		
	SO ₂	NO _x	Heat Input
Unit ID: Unit 1, Unit 2			
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 (<i>Optional SO₂ Emissions Data Protocol for Gas-Fired and Oil-Fired Units</i>)			
Excepted monitoring system pursuant to 40 CFR part 75, appendix E (<i>Optional NO_x Emissions Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units</i>)			
Low Mass Emissions excepted monitoring (LME) pursuant to 40 CFR 75.19 (<i>Optional SO₂, NO_x, and CO₂ Emissions Calculation for Low Mass Emissions (LME) Units</i>)			
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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 NO_x 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 NO_x 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 SO₂ 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 SO₂ Group 1 source and each CSAPR SO₂ 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 SO₂ Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO₂ 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) SO₂ emissions requirements.

- (1) CSAPR SO₂ 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 SO₂ Group 1 source and each CSAPR SO₂ Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO₂ 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 SO₂ emissions for such control period from all CSAPR SO₂ Group 1 units at the source.
 - (ii). If total SO₂ emissions during a control period in a given year from the CSAPR SO₂ Group 1 units at a CSAPR SO₂ Group 1 source exceed the CSAPR SO₂ Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:
 - (A). The owners and operators of the source and each CSAPR SO₂ Group 1 unit at the source shall hold the CSAPR SO₂ Group 1 allowances required for deduction under 40 CFR 97.624(d); and
 - (B). The owners and operators of the source and each CSAPR SO₂ 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 SO₂ Group 1 assurance provisions.
 - (i). If total SO₂ emissions during a control period in a given year from all CSAPR SO₂ Group 1 units at CSAPR SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂

- emissions exceeds the respective common designated representative's assurance level; and
- (B). The amount by which total SO₂ emissions from all CSAPR SO₂ Group 1 units at CSAPR SO₂ Group 1 sources in West Virginia for such control period exceed the state assurance level.
- (ii). The owners and operators shall hold the CSAPR SO₂ 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 SO₂ emissions from all CSAPR SO₂ Group 1 units at CSAPR SO₂ Group 1 sources in West Virginia during a control period in a given year exceed the state assurance level if such total SO₂ emissions exceed the sum, for such control period, of the state SO₂ 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 SO₂ emissions from all CSAPR SO₂ Group 1 units at CSAPR SO₂ 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 SO₂ emissions from the CSAPR SO₂ Group 1 units at CSAPR SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ Group 1 allowances held for compliance.
- (i). A CSAPR SO₂ 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 SO₂ Group 1 allowance that was allocated for such control period or a control period in a prior year.
- (ii). A CSAPR SO₂ 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 SO₂ 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 SO₂ 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 SO₂ Group 1 allowance is a limited authorization to emit one ton of SO₂ 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 SO₂ 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 SO₂ 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 NO_x 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 SO₂ Group 1 source and each CSAPR SO₂ 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 SO₂ 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 SO₂ Group 1 Trading Program.
- (2) The designated representative of a CSAPR SO₂ Group 1 source and each CSAPR SO₂ Group 1 unit at the source shall make all submissions required under the CSAPR SO₂ 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 SO₂ Group 1 Trading Program that applies to a CSAPR SO₂ Group 1 source or the designated representative of a CSAPR SO₂ Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO₂ Group 1 units at the source.
- (2) Any provision of the CSAPR SO₂ Group 1 Trading Program that applies to a CSAPR SO₂ Group 1 unit or the designated representative of a CSAPR SO₂ Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO₂ 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 SO₂ Group 1 source or CSAPR SO₂ 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. SO₂ 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@dep.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

Promoting a healthy environment

West Virginia Department of Environmental Protection • Division of Air Quality

Plant Name: Mitchell Power Station	Permit #: R33-3948-2027-6
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2. **SO₂ 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
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2. **SO₂ 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.

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.**

Mitchell (WV) Facility (Source) Name	West Virginia State	3948 Plant Code
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STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

[illegible]

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)

Acid Rain - Page 3

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.

Mitchell	WV	3948
Plant Name	State	Plant Code

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 <u>Phase I</u> dry bottom wall-fired boilers)	X	X				
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for <u>Phase I</u> tangentially fired boilers)						
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for <u>Phase II</u> dry bottom wall-fired boilers)						
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for <u>Phase II</u> 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)						

NO_x Compliance – Page 2

STEP 2, cont'd

Mitchell Plant Name (From Step 1)

	ID#	ID#	ID#	ID#	ID#	ID#
	Type	Type	Type	Type	Type	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, <u>2019</u>

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	<i>Scott A. Weaver</i>	Date <i>12-18-18</i>

APPENDIX G

Class II General Permit Registration
G60-C057A

West Virginia Department of Environmental Protection
Joe Manchin, III *Division of Air Quality* *Randy C. Huffman*
Governor *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

A handwritten signature in blue ink, appearing to read "William F. Durham", is written over a horizontal line.

William F. Durham
Director

Issued: August 8, 2014

Class II General Permit G60-C
Emergency Generator

Page 2 of 3

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-] 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.

Class II General Permit G60-C
Emergency Generator

Page 3 of 3

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

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_20 Please refer to Jessee Direct at 14:22 to 15:5, and explain how the boiler exit gas duct replacement expense is affected by the decision to modify in place.

RESPONSE

The expense incurred in 2024 to replace the Big Sandy Unit 1 boiler exit gas duct was lower than it would have been had the prior in-place modifications not occurred. The in-place modifications to the Big Sandy Unit 1 exit gas ductwork were performed during the conversion of Big Sandy Unit 1 from coal to natural gas, which took place in 2015 and 2016. Kentucky Power completed the prior, in-place modifications to achieve the full generating capability of the new gas boiler by reducing the exit gas pressure drop across the existing precipitator and to remove the retired components not needed after the conversion from coal to natural gas. The removal of the structure and components performed during the modification in 2015 and 2016 reduced the cost associated with the 2024 boiler exit gas duct replacement. The prior, in-place modifications also allowed for a shorter outage window and reduced work scope in 2024.

Witness: Robert A. Jessee

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_21 Please refer to Jessee Direct at 17:6-15, and explain whether any carrying costs are were assigned to the Company or included in base rates or environmental rates in this case related to costs allocated asymmetrically to Wheeling Power that may be shifted back to the Company.

RESPONSE

No, the Company has not proposed to recover any costs associated with the asymmetrical cost allocation to Wheeling Power for the Mitchell Plant as part of this proceeding. As explained by Company Witness Wolffram, the Company's CPCN to extend its interest in energy and capacity from Mitchell is still pending. To the extent that application is approved, the Company will file an application to begin cost recovery of the amounts necessary to reflect the Company's full 50% interest in the energy and capacity from the Mitchell Plant after that approval.

Witness: Tanner S. Wolffram

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025
Page 1 of 2

DATA REQUEST

- JI 2_22** Please refer to the Direct Testimony of Michele Ross on Behalf of Kentucky Power Company (“Ross Direct”) at 4:7-10 and 5:21 to 6:14, and
- a. Provide any documents in which the Company has evaluated its service territory terrain and vegetative conditions to other utilities in the Commonwealth or outside the Commonwealth.
 - b. Explain where the Company ranks regarding number of customers per mile of:
 - i. Transmission circuit compared to other
 - 1. Utilities in the Commonwealth
 - 2. Utilities within the US
 - ii. Distribution circuit compared to other
 - 1. Utilities in the Commonwealth
 - 2. Utilities within the US

RESPONSE

The Company objects to this request as unduly burdensome to the extent it seeks information that is not maintained in the ordinary course of business. The Company further objects because the request is vague, undefined, and overly broad. Subject to and without waiving these objections, the Company states that it has not performed any formal comparative analysis regarding terrain or vegetative conditions compared to other utilities in either the Commonwealth or elsewhere. However, the Company submitted rebuttal testimony by Company Witness Eugene Shlatz which included a discussion of the Company’s geographical situation compared to a specified peer group in Case 2021-00370.

b.i.1-2. The Company objects to this request as unduly burdensome to the extent it seeks information that is not maintained in the ordinary course of business. Subject to and without waiving this objection, the Company states that it has not performed any such formal analysis. The product and procedure to perform such an analysis would be similar to what the Company provides below in part b.ii.1 by utilizing publicly available data set forth by EEI and in FERC Form 1 data.

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025
Page 2 of 2

b.ii.1-2. The Company objects to this request as unduly burdensome to the extent it seeks information that is not maintained in the ordinary course of business. Subject to and without waiving this objection, the Company states that it does not have the requested information for distribution utilities across the United States. The table below ranks investor-owned utilities in Kentucky for customers per distribution line mile:

Order	Utility	Customers per Mile
1	Louisville Gas & Electric	256
2	Duke Energy	66
3	Kentucky Utilities	34
4	Kentucky Power Company	16

Witness: Michele Ross

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

- JI 2_23** Please refer to Ross Direct at 15:7-17, and explain:
- a. How right-of-way is defined or determined;
 - b. Once widened does an area become inside right-of-way?
 - c. Will TIR cost go up with widened rights-of-way?

RESPONSE

- a. Right-of-way means the right to pass over property owned by another party; the path or throughfare over which passage is made; that strip of land or corridor over which facilities such as highways, railroads, or power lines are constructed and maintained.
- b. Yes. Once the circuit sections have been widened, any vegetation activity performed in those widened ROW sections will be considered in-ROW activities.
- c. After a ROW has been widened, there may be minimal additions to TIR costs as the Company would then have to perform maintenance activities such as vegetation spraying in the widened areas. The Company will realize restoration costs and reliability improvements will be seen by the customer.

Witness: Michele Ross

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_24 Please refer to Ross Direct at 16, Figure MR-5, and explain why TOR cost was significantly lower in 2024 than past years.

RESPONSE

The Company objects to the extent the request mischaracterizes the Direct Testimony of Company Witness Ross. The Company further objects because the request is vague, undefined, and overly broad. Subject to and without waiving these objections, the Company states as follows:

The distribution capital budget was less in 2024 than in 2023. The Company allocates capital dollars based upon factors that may or may not change year over year, like mandated programs, load risk, reliability needs, and restoration. This is one of the reasons that the proposed \$18 million capital adjustment for TOR is necessary, as it would allow for the Company to ensure that these dollars are dedicated to the TOR Program, which ultimately will benefit customers in the form of increased reliability as shown in the Direct Testimony of Company Witness Ross.

Witness: Michele Ross

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_25 Please confirm that the Company is not seeking any cost recovery for AMI deployment in this case. If any cost recovery is being sought, please explain and provide details on any recovery being sought.

RESPONSE

Confirmed.

Witness: Tanner S. Wolfram

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_26 Please confirm that the Company will not seek cost recovery for the deployment of AMI until deployment is completed and the Company can assess what, if any, costs have been incurred over savings.

RESPONSE

At this time, the Company is unable to confirm its future plans regarding recovery of AMI deployment.

Witness: Tanner S. Wolfram

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_27 Please confirm that the Company will not implement any changes in disconnection or reconnection policies related to AMI except in a future case and after review and approval by the Commission.

RESPONSE

Confirmed.

Witness: Tanner S. Wolffram

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

- JI 2_28** Please refer to the Direct Testimony of Stevi N. Cobern on Behalf of Kentucky Power Company (“Cobern Direct”) at 18:13-19 and the response to Joint Intervenor’s First Set of Data Requests number 40 (“JI 1-40”), and explain whether the Company tracks how many customers receive HEART and THAW funding.
- a. If yes, provide the number of customers receiving funding from each program;
- b. If now, why not?

RESPONSE

- a. Yes. Consistent with the Company’s response to JI 1_40 and JI 1_41, the Company provides the number of customers who receive HEART and THAW funding annually in its Home Energy Assistance update provided in the Post-Case Files for Case No. 2019-00366 which is publicly available on the Commission’s website (psc.ky.gov).
- b. Not applicable.

Witness: Stevi N. Cobern

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_29 Please refer to the Direct Testimony of John D. Cullop on Behalf of Kentucky Power Company (“Cullop Direct”) at 2:9-13 and 8:2-5, as well as the Final order entered on October 07, 2013 in Case No. 2012-00578 allowing for FGD costs for Mitchell to be “recovered through the environmental surcharge (Tariff ES.) ... at least until the Commission sets new base rates for a period commencing after June 30, 2020,” and explain:

- a. Why the Company proposing to continue excluding Mitchell FGD costs from the base environmental revenue calculation; and
- b. What the impact on each tariff class is of collecting the rates through this mechanism rather than base rates

RESPONSE

a. Recovery of Mitchell FGD costs through the environmental surcharge provides customers with the benefit of accumulated depreciation and the resulting lower return on plant in service each month. Additionally, in recent years the Commission has reduced the Company’s authorized ROE for the environmental surcharge by 10-basis points.

b. The Company has not prepared the requested analysis.

Witness: Tanner S. Wolfram

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_30 Please refer to Cullop Direct at 8:6 through 10:2, and explain whether each amount removed related to Mitchell FGD was or would be collected through the environmental surcharge.

RESPONSE

Yes. The test-year Mitchell FGD expense amounts (Adjustment W19) and revenue amounts (Adjustment W08) were collected solely through the environmental surcharge, as approved in the Company's last base rate case, Case No. 2023-00159. The Company is proposing the same treatment related to Mitchell FGD revenues and expenses in this case.

Witness: John D. Cullop

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_31 Please refer to the Direct Testimony of Jaclyn N. Cost (“Cost Direct”) at 5:18 to 6:9 and the Direct Testimony of Nicole M. Coon on Behalf of Kentucky Power Company (“Coon Direct”) at 5:13-23, and confirm whether transmission and distribution costs are affected by the amount of energy used. If anything but confirmed, explain.

RESPONSE

The Company cannot confirm the request. The transmission and distribution functions are classified as demand-related and customer-related costs. Costs incurred to meet peak demand or connect and maintain a customer connection are considered fixed costs. These fixed costs associated with transmission and distribution investment and expenses are incurred regardless of the level of energy sales.

Witness: Nicole M. Coon

Witness: Jaclyn N. Cost

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_32 Please refer to Coon Direct at 10:2-8, and provide the dates and level of the 12 CPs used to allocate production plant. Explain whether each was weather-normalized.

RESPONSE

Please see KPCO_R_AG_KIUC_1_94_Attachment1. The worksheet labeled “Manual Inputs” contains the test year coincident peak dates and times for Kentucky Power. The dates and hours are not weather-normalized. However, the kWh amounts under the section “Test Year Inputs from Revenue Process” on the same worksheet are weather-normalized.

Witness: Nicole M. Coon

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_33 Please refer to Coon Direct at 10:15-19, and provide the dates and level of the 12 CPs used to allocate transmission plant. Explain whether each was weather-normalized.

RESPONSE

Please see KPCO_R_AG_KIUC_1_94_Attachment1. The worksheet labeled “Manual Inputs” contains the test year coincident peak dates and times for Kentucky Power. The dates and hours are not weather-normalized. However, the kWh amounts under the section “Test Year Inputs from Revenue Process” on the same worksheet are weather-normalized.

Witness: Nicole M. Coon

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_34 Please refer to Coon Direct at 10:21 to 11:3, and provide the dates and level of the 12 CPs used to allocate distribution plant. Explain whether each was weather-normalized.

RESPONSE

Please see KPCO_R_AG_KIUC_1_94_Attachment1. The worksheet labeled “Manual Inputs” contains the test year coincident peak dates and times for Kentucky Power. The dates and hours are not weather-normalized. However, the kWh amounts under the section “Test Year Inputs from Revenue Process” on the same worksheet are weather-normalized.

Witness: Nicole M. Coon

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025
Page 1 of 2

DATA REQUEST

- JI 2_35** Please refer to the Direct Testimony of Michael M. Spaeth on Behalf of Kentucky Power Company (“Spaeth Direct”) at 5:7-12, and confirm the base fuel rate changed during the test period from \$0.0261 \$/kWh to \$0.03880 \$/kWh.
- a. How was this change incorporated into proposed base rates? I.e., was this incorporated on a pro rata basis over the test period, or was only the later rate used?
- b. Confirm this represents a greater than 48% increase in fuel costs
- i. If anything other than confirmed, explain;
- ii. If confirmed, please explain the cause of this increase.

RESPONSE

Confirmed. The Company’s base fuel rate changed from \$0.02612 /kWh to \$0.03880 /kWh during the test year in accordance with the Commission’s December 13, 2024 Order in Case No. 2023-00008 which stated:

Having reviewed the evidence, the Commission finds that Kentucky Power’s proposed base fuel rate of \$0.03380 per kWh with January 2022 as the representative month is reasonable and should be accepted. The new base fuel rate should be placed into effect with service rendered on or after Kentucky Power’s first billing cycle following the date of this Order.

The first billing cycle following this Order was December 30, 2024.

- a. Please see KPCO_R_KPSC_1_55_Attachment28_SpaethWP8 that incorporates the base fuel rate change. The Company’s per books base revenues are calculated utilizing the applicable non-adjusted billing units times the applicable base rate (inclusive of base fuel). The column labeled “Rate Annualization” applies the adjusted billing units to the base rate (inclusive of base fuel) in effect at the end of the test year.

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025
Page 2 of 2

b. Not confirmed. The base fuel rate only represents a portion of the Company's fuel costs. The Company collects or credits any fuel costs that are above or below the base amount through its fuel adjustment clause. Additionally, there are fuel costs that are not eligible for recovery through the fuel adjustment clause, instead these are recovered through the Company's purchase power adjustment. Notably, the base fuel rate is established on a representative month within the Company's two-year fuel adjustment clause as required by 807 KAR 5:056. Additionally, fuel costs are variable and will thus fluctuate month to month.

Witness: Michael M. Spaeth

Witness: John D. Cullop

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_36 Please refer to Spaeth Direct at 6:16-18 and 7:3-10, and explain what costs are meant by “non-Mitchell FGD”? What other units operated by the Company have flue gas desulfurization?

RESPONSE

The phrase “non-Mitchell FGD” refers to costs relating to projects in the Company’s environmental compliance plan other than the Mitchell FGD project.

Witness: John D. Cullop

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_37 Please refer to Spaeth Direct at 9:5-9, and explain which functional and class categorizations are “basic service-related”?

RESPONSE

Basic service-related costs are functionally allocated within the class cost-of-service-study as “customer-related,” as they encompass the most basic costs of serving customers, and from a cost-based ratemaking perspective, should be recovered through basic service charges. Some examples of “basic service-related costs” are meters, meter reading, billing, and portions of the distribution system such as poles, lines, and transformers. Customer-related costs can be found in the CCOS study, KPCO_R_KPSC_1_54_Attachment1, in the column labeled “Function” and the rows labeled “Customer.”

Witness: Michael M. Spaeth

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_38 Please refer to Spaeth Direct at 10:16-21, and explain how the cost associated with connecting a residential customer to the distribution system of \$46.19 was derived, including what categories of costs were included.

RESPONSE

The Company calculated the cost to connect a residential customer to the distribution system by dividing the total customer-related costs (as derived by the class cost-of-service study) by the number of customer bills in the test year. The calculation, shown in KPCO_R_KPSC_2_19_Attachment1, divides \$72,250,836 in customer-related RS Revenue Requirement (per KPCO_R_KPSC_1_54_Attachment1) by 1,564,142 bills, resulting in a \$46.19 full-cost customer charge.

Please refer to the Direct Testimony of Company Witness J. Wolfram pg. 9 lines 7-20 for a summary of how the results of the zero-intercept study are used in the cost-of-service study to classify customer facility costs.

Witness: Michael M. Spaeth

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_39 Please refer to Spaeth Direct at 11:10-12 and, e.g., Response to JI 1-50, and explain how the Company determined lower income customers are disadvantageded by the current basic service charge given that the Company “does not maintain customer income information.”

RESPONSE

The Company does not maintain customer income information. In Response to JI 1_50, the Company noted that the scope of the analysis is limited to the Company’s and federal assistance programs (LIHEAP, HEART, etc.).

As shown in the Company’s response to JI 1_95, residential customers receiving LIHEAP assistance, which is a federal income-based program, have higher usage in the winter months than the residential class as a whole. In the data, this difference is understated, as the LIHEAP-assisted customers’ higher usage is included in the residential class usage as a whole, bringing up the average. Given that LIHEAP-assisted customers typically experience higher winter peaks of energy usage, recovering fixed distribution costs through volumetric energy charges disadvantages economically assisted customers.

Please note that the intent of the proposed residential rate design in this proceeding is not income-driven. The proposed residential rate design, as described in the Direct Testimonies of Company Witnesses Spaeth and Wolfram, works to reduce intraclass subsidization of lower usage customers by higher usage customers, reduce high summer and winter bills, and provide bill stability throughout the year.

Witness: Michael M. Spaeth

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_40 Please refer to Spaeth Direct at 12:10-15, and provide:

- a. The number of customers using electric heating;
- b. The number of customers using electric heating via heat pumps;
- c. The number of customers using electric heating via resistance heating;
and
- d. The number of customers using electric heating via any other means.

RESPONSE

- a. The Company provided the number of residential customers using electric heating in response to JI_1_49. Note that revenue class code 10 indicates a non-electric heating customer and revenue class code 20 indicates an electric heating customer. See KPCO_R_JI_1_29_Attachment1, which reflects the unadjusted December ending number of active electric heating residential customers.
- b. The Company does not maintain specific information on the type or apparatus of electric heating that customers utilize.
- c. See subpart b. Note that heat pumps commonly utilize resistance heating to supplement heating in cold conditions, resulting in significant kWh usage.
- d. See subpart b.

Witness: Michael M. Spaeth

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

- JI 2_41** Please refer to Spaeth Direct at 16:8-20, and:
- a. Provide the number of customers using under 600 kWh;
 - b. Confirm the increased energy charge for usage under 600 kWh is a fixed increase in total cost for any customer using greater than 600 kWh

RESPONSE

- a. See the Company's response to AG_KIUC_2_18.
- b. The Company is not able to confirm. While the 0-600 kWh block 1 energy charge results in an increase compared to the current energy charge, all usage above 600 kWh, within the second energy block, results in a decrease compared to the current energy charge. Wholistically, then, no customer with usage above 600 kWh experiences a fixed increase in total cost.

Witness: Michael M. Spaeth

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_42 Please refer to Spaeth Direct at 17:3-4, and explain how demand-related costs are fixed.

RESPONSE

Demand-related costs reflect costs that the utility must incur to meet peak demand and fulfill capacity needs. Demand costs are fixed in relation to the production of energy, as they are irrespective of volumetric energy use. Demand-related costs are, for example, the costs of generation capacity, transmission lines, distribution substations and lines, and transformers. In the short run, these costs are fixed but can change over time in the long run as new infrastructure or capacity investments occur. Within the electric utility industry, demand-related costs are treated as fixed for ratemaking purposes.

Witness: Michael M. Spaeth

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_43 Please refer to the Direct Testimony of Franz D. Messner on Behalf of Kentucky Power Company (Messner Direct) at Figured FDM-1, and confirm whether the current per books capital structure matches that approved in the Company's previous base rate case. If anything but confirmed, explain the reason for any difference.

RESPONSE

The Company objects to this request to the extent it seeks information that is not reasonably calculated to lead to the discovery of relevant or admissible evidence. The Company further objects because the request is vague, undefined, and overly broad. Subject to and without waiving these objections, the Company states as follows:

The Company confirms that its capital structure consists of long term debt, short term debt, and equity consistent with the capital structure approved in the last base rate case. However, the per books amounts differ from that approved in the Company's previous base rate case for a variety of reasons largely driven by the Company's operational and financial performance since the last base case was approved which resulted in different amounts of long-term debt, short-term debt and equity.

Witness: Franz D. Messner

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_44 Please refer to Messner Direct at 10:13-14, and explain the impact of exclusion of sale of accounts receivable.

RESPONSE

The Company objects because the request is vague, undefined, and overly broad. Subject to and without waiving these objections, the Company states as follows:

Please see the Company's response to KPSC 3_9.

Witness: Franz D. Messner

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_45 Please refer to Messner Direct at 12:1-20, and provide the amount of the issuance expense.

RESPONSE

The issuance expense associated with the mandatory remarketing of the WVEDA bonds in 2023 was \$340,000. Please refer to Section V, Workpaper S-3 Page 1 – Long Term Debt.

Witness: Franz D. Messner

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_46 Please refer to the Direct Testimony of Adrien M. McKenzie, CFA, on Behalf of Kentucky Power Company (“McKenzie Direct”) at 10:19-20, and explain whether attrition alone explains the Company’s inability to earn its authorized rate of return. If anything but confirmed, explain each reason for the Company’s inability to earn its authorized rate of return and the relative contribution.

RESPONSE

The Company objects to the extent the request mischaracterizes the Direct Testimony of Company Witness McKenzie. The Company objects because the request is vague, undefined, and overly broad. Subject to and without waiving these objections, the Company states as follows:

Yes, as the term “attrition” is used in context on page 10 lines 19-20 of Company Witness McKenzie’s testimony. As further explained in Company Witness McKenzie’s Direct Testimony at 26:4-6, the term “attrition” refers to the deterioration of the actual return below the allowed return that occurs when the relationships between revenues, costs, and rate base used to establish rates do not reflect the actual costs incurred to serve customers during the period that rates are in effect.

Witness: Adrien M. McKenzie

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_47 Please refer to McKenzie Direct at 21:6-7, and explain why only utilities that have paid a common dividend and have not announced a dividend cut are included in the proxy group.

RESPONSE

The Company objects to the extent the request mischaracterizes the Direct Testimony of Company Witness McKenzie. Subject to and without waiving this objection, the Company states as follows:

One of the primary methods customarily relied on in regulatory proceedings to estimate the cost of equity is the discounted cash flow (“DCF”) model. As explained in Company Witness McKenzie’s Direct Testimony at 41:4-17, the DCF model assumes that the rate of return to stockholders consists of two parts: 1) dividend yield; and 2) growth. Because the dividend yield is crucial to obtaining a meaningful DCF result, the model’s usefulness is severely hampered for firms that do not pay common dividends. As the Federal Energy Regulatory Commission has noted, for example:

[A] DCF analysis can only be conducted for companies that pay dividends. . . . Basing a CAPM study on only dividend-paying companies is therefore appropriate in this context, where the Commission is looking to the CAPM study to corroborate the results of a DCF analysis, because doing so produces a growth rate input that is more representative of the DCF proxy group than a CAPM study based on non-dividend-paying companies would be. *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 111 (2015).

Dividends constitute an important component of the return that investors require to commit their capital to a utility, and the magnitude and stability of dividend payments are a key focus of investment decision-makers. One of the principal attractions that utility stocks hold for investors is their relatively high dividend yields when compared to other market sectors. Accordingly, a lack of common dividends or uncertainty over future dividend payments undermines the ability of a firm to serve as a meaningful proxy when estimating the cost of equity. Company Witness McKenzie would note that although this is an important criterion in selecting a proxy group, no companies were eliminated from his analysis on this basis.

Witness: Adrien M. McKenzie

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

JI 2_48 Please refer to McKenzie Direct at 25:7-19, and to the extent able quantify the impact of the high concentration of sales to industrial customers relative to other utilities impacts risk and the proposed return on equity.

RESPONSE

The Company objects to the extent the request mischaracterizes the Direct Testimony of Company Witness McKenzie. Subject to and without waiving this objection, the Company states as follows:

Given the inherent imprecision associated with the accepted financial models used to estimate the cost of equity, it is not generally possible to isolate the influence of one specific risk factor on investors' required cost of equity. Thus, although Kentucky Power's relatively high concentration of sales to industrial customers increases the Company's risks, there is no way to precisely quantify the impact of this exposure on the cost of equity. The fact that Company Witness McKenzie's recommended return on equity range was based on the results for his proxy group—and did not incorporate any adjustment for the risks posed by Kentucky Power's relatively high concentration of industry customers, history of earnings attrition and greater financial leverage—further supports the reasonableness of the 10.0% ROE requested by Kentucky Power.

Witness: Adrien M. McKenzie

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

- JI 2_49** Please refer to McKenzie Direct at 29:19 to 30:2, and explain:
- a. How has the Company considered mitigating the “elevated carbon transition risks due to its significant coal-fired generation”?
 - b. Has the Company attempted to quantify the impact of the elevated risk on the proposed return on equity?
 - i. If yes, please provide documentation;
 - ii. If no, why not?

RESPONSE

The Company objects to the extent the request mischaracterizes the Direct Testimony of Company Witness McKenzie. The Company objects because the request is vague, undefined, and overly broad; specifically, use of the terms “considered” and “mitigated.” Subject to and without waiving these objections, the Company states as follows:

- a. As noted at page 29 of Company Witness McKenzie’s Direct Testimony, the Company has sought and received approval for environmental cost recovery riders, which help to mitigate the impact of carbon transition risk. As Company Witness McKenzie’s testimony documents, although environmental recovery riders are perceived as supportive, the investment community continues to view reliance on coal generation as a risk exposure.
- b. The Company has not attempted to quantify the impact of elevated carbon transition risk on investors’ required return on equity, nor was this necessary to support Company Witness McKenzie’s conclusions or recommendations. Moreover, as discussed in Company Witness McKenzie’s Direct Testimony, the cost of equity is not observable and can only be estimated. Given the inherent imprecision associated with the accepted financial models used to estimate the cost of equity, it is not generally possible to isolate the influence of one specific risk factor on investors’ required cost of equity.

Witness: Adrien M. McKenzie

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025
Page 1 of 3

DATA REQUEST

Jl 2_50

Please refer to the Supplemental Direct Testimony of Alex E. Vaughn on Behalf of Kentucky Power Company in Case No. 2025-00175, Electronic Application Of Kentucky Power Company For Approval Of (1) A Certificate Of Public Convenience And Necessity To Make The Capital Investments Necessary To Continue Taking Capacity And Energy From The Mitchell Generating Station After December 31, 2028, (2) An Amended Environmental Compliance Plan, (3) Revised Environmental Surcharge Tariff Sheets, And (4) All Other Required Approvals And Relief, and respond to the following questions:

- a. Please state and itemize what costs related to the Mitchell Plant Unit 2 cooling tower structural needs, if any, are included in the adjustments to the test year expense included in this case?
- b. Please explain how, if at all, the test year level of expense is impacted by the update provided by Mr. Vaughn in is Supplemental Direct Testimony in Case No. 2025-00175?
- c. Please provide a detailed account of the cost of each of the Options 1-4 described by Mr. Vaughn in his Supplemental Direct Testimony in Case No. 2025-00175 at 3:3-9?
- d. Please explain how the adjustments to the test year level of expense in this case would be impacted by each of the Options 1-4 described by Mr. Vaughn in his Supplemental Direct Testimony in Case No. 2025-00175 at 3:3-9?
- e. Please explain whether the costs related to each of the Options 1-4 described by Mr. Vaughn in his Supplemental Direct Testimony in Case No. 2025-00175 at 3:3-9 would be included or eligible to be included in the proposed Generation Rider (Tariff G.R.) in this case, broken down by expense and by each of:
 - i. RB = Non-Environmental Rate Base for Mitchell represented by the sum of plant in service less accumulated depreciation;
 - ii. CWIP = Construction Work in Progress for Non-Environmental Mitchell Projects;

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025
Page 2 of 3

- iii. ROR = Rate of Return on Non-Environmental Mitchell Rate Base;
- iv. DE = Depreciation Expense;
- v. PT = Property Taxes;
- vi. OU = Cumulative difference between revenues received and actual costs for the reporting period, representing the (over) or under recovery.

RESPONSE

The Company objects to this request to the extent it seeks information that is not reasonably calculated to lead to the discovery of relevant or admissible evidence as it is seeking information about another unrelated case in which the Joint Intervenor chose not to intervene. The Company further objects to the extent the request mischaracterizes the testimony of Alex Vaughan filed in Case No. 2025-00175. Subject to and without waiving these objections, the Company states as follows:

- a. The Company has not made any adjustments to its test year cost-of-service for the cooling tower structural needs. Please see the Direct Testimony of Company Witness Jessee, specifically Figure RAJ-4 for the capital additions related to this effort included within the Company's test year.
- b. There is no impact.
- c. The Company objects to this request to the extent it seeks information that is beyond the scope of this proceeding and not reasonably calculated to lead to the discovery of relevant or admissible evidence as it is seeking information about another unrelated case in which the Joint Intervenor chose not to intervene.
- d. The Company objects to this request as unduly burdensome to the extent it seeks information that is not maintained in the ordinary course of business. The Company further objects that the request calls for speculation regarding an incomplete hypothetical scenario. Subject to and without waiving these objections, the Company states as follows: See subpart b.

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025
Page 3 of 3

e. As explained in Company Witness Vaughan's Supplemental Testimony in Case No. 2025-00175, the Company has not decided on a solution to address the structural needs of the Mitchell Plant Unit 2 cooling tower. Further, the Company has not made a determination as to how it will propose to recover those costs at this point as it would be premature to do so without knowing the proposed solution and without knowing if the Generation Rider is approved in this proceeding.

Witness: Tanner S. Wolffram

Kentucky Power Company
KPSC Case No. 2025-00257
Joint Intervenor's Second Set of Data Requests
Dated October 23, 2025

DATA REQUEST

- JI 2_51** Please refer to the presentation given in the informal technical conference (“ITC”) on Sept. 30, 2025 at slide 7 (“RESIDENTIAL RATE PROPOSAL”), and explain any efforts the Company has made to reach out to the following groups of residential ratepayers regarding high energy use, energy efficiency or demand-side management programs:
- a. The two-thirds of customers using electric heating; and
 - b. The 14% of customers with usage of greater than 3,000 kWh/month in the winter months.

RESPONSE

The Company objects to the extent the request mischaracterizes the information contained in the presentation given at the informal technical conference on September 30, 2025. Subject to and without waiving this objection, the Company states as follows:

a.-b. The Company has engaged in general marketing of its new DSM offerings, including news releases, updated website content, social media posts, bill inserts, customer emails, and account specific portal messaging for customers with high bill alerts. The Company intends to conduct a direct mail campaign to previous LIHEAP participants. The Company also provided its DSM program administrator a list of high-usage customers for targeted marketing for the Company’s new DSM programs. The Company’s DSM program administrator has also been actively involved in in-person community outreach with local non-profit organizations related to the Company’s DSM programs.

The Company has also been actively engaged in support of the Community Action Agencies that implement its TEE program to ensure further aid for weatherization readiness for qualifying customers.

Witness: Tanner S. Wolffram

VERIFICATION

The undersigned, Stevi N. Cobern, being duly sworn, deposes and says she is a Regulatory Consultant Principle for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Stevi N. Cobern
Stevi N. Cobern

Commonwealth of Kentucky)
)
County of Boyd)

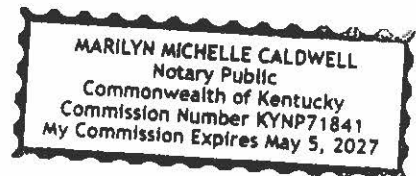
Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stevi N. Cobern, on October 29, 2025.

Marilyn Michelle Caldwell
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841



VERIFICATION

The undersigned, Nicole M. Coon, being duly sworn, deposes and says she is a Regulatory Consultant Principal for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.



Nicole M. Coon

State of Ohio)
)
County of Franklin)

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Nicole M. Coon, on October 30, 2025.



Notary Public

My Commission Expires N/A

Notary ID Number _____



BRETT E. SCHMIED, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

VERIFICATION

The undersigned, Jaclyn N. Cost, being duly sworn, deposes and says she is a Regulatory Manager for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Jaclyn Cost
Jaclyn N. Cost

State of Ohio)
)
County of Franklin)

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jaclyn N. Cost, on 10/30/25.

Brett E. Schmied
Notary Public



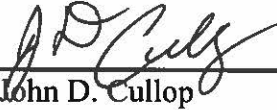
BRETT E. SCHMIED, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires N/A

Notary ID Number _____

VERIFICATION

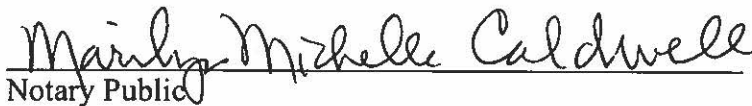
The undersigned, John D. Cullop, being duly sworn, deposes and says he is the Regulatory Consultant Senior for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

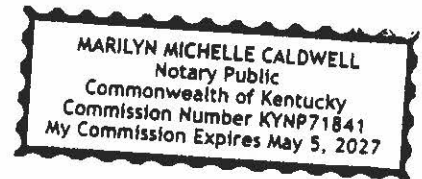

John D. Cullop

Commonwealth of Kentucky)
)
County of Boyd)

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John D. Cullop, on 10/27/2025.


Notary Public



My Commission Expires May 5, 2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Robert A. Jessee, being duly sworn, deposes and says he is the Vice President of Generating Assets East for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Signed by:

Robert A. Jessee

1DFF2235C9E944E

Robert A. Jessee

KY

Kentucky

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County
and State, by Robert A. Jessee, on 10/31/2025 | 2:03 PM EDT.

Signed by:

Michelle Caldwell

E0B19C7AC21F421

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
COMMONWEALTH OF KENTUCKY
Commission #KYNP71841
My Commission Expires 5/5/2027

My Commission Expires 05/05/2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Adrien M. McKenzie, being duly sworn, deposes and says he is the President of FINCAP, Incorporated, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

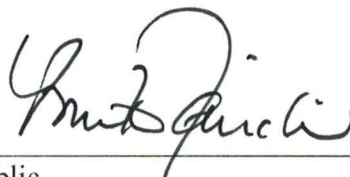


Adrien M. McKenzie

STATE OF TEXAS)
)
COUNTY OF TRAVIS)

Case No. 2025-00257

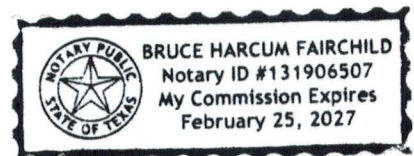
Subscribed and sworn to before me, a Notary Public in and before said County and State, by Adrien M. McKenzie, on OCTOBER 28, 2025.



Notary Public

My Commission Expires 2/25/2027

Notary ID Number 131906507



VERIFICATION

The undersigned, Franz D. Messner, being duly sworn, deposes and says he is the Managing Director of Corporate Finance for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

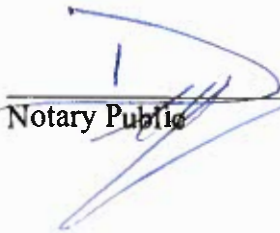


Franz D. Messner

State of Ohio

)
)
)
Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Franz D. Messner, on October 28, 2025



Notary Public

My Commission Expires _____

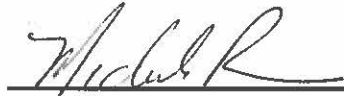
Notary ID Number _____



David C. House, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

VERIFICATION

The undersigned, Michele Ross, being duly sworn, deposes and says she is a Vice President of Distribution Region Operations for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.



Michele Ross

Commonwealth of Kentucky)

)

Case No. 2025-00257

County of Boyd)

)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Michele Ross, on October 31, 2025.


Notary Public

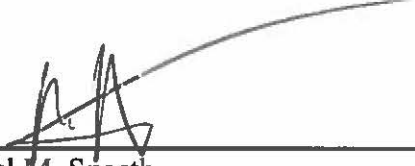
My Commission Expires May 5, 2027

Notary ID Number KYNP71841

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

VERIFICATION

The undersigned, Michael M. Spaeth, being duly sworn, deposes and says he is the Regulatory Pricing and Analysis Manager for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.



Michael M. Spaeth

State of Ohio)
)
County of Franklin) Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Michael M. Spaeth, on November 3, 2025.



Notary Public

My Commission Expires N/A

Notary ID Number _____



BRETT E. SCHMIED, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

VERIFICATION

The undersigned, Clinton M. Stutler, being duly sworn, deposes and says he is the Director of Natural Gas Procurement for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Signed by:

Clinton M. Stutler

D08113A50D0847D

Clinton M. Stutler

Commonwealth of Kentucky)

)

Case No. 2025-00257

County of Boyd)

)

Subscribed and sworn to before me, a Notary Public in and before said County
and State, by Clinton M. Stutler, on 10/29/2025 | 11:02 AM EDT.

Signed by:

Michelle Caldwell

E9B1BC7AC31F421

Notary Public

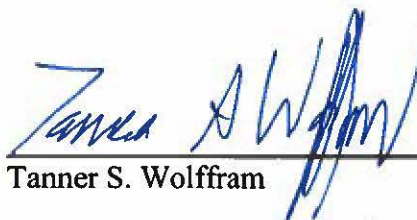
MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
COMMONWEALTH OF KENTUCKY
Commission #KYNP71841
My Commission Expires 5/5/2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Tanner S. Wolffram, being duly sworn, deposes and says he is the Director of Regulatory Services for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.


Tanner S. Wolffram

Commonwealth of Kentucky)
)
County of Boyd)

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County
and State, by Tanner S. Wolffram, on October 31, 2025.


Notary Public



My Commission Expires May 5, 2027

Notary ID Number KYNP71841