STATE OF MISSISSIPPI
AIR POLLUTION CONTROL
TITLE V PERMIT

TO OPERATE AIR EMISSIONS EQUIPMENT

THIS CERTIFIES THAT

Mississippi Power Company, Plant Victor J Daniel
13201 Highway 63 North
Moss Point, Mississippi
Jackson County

has been granted permission to operate air emissions equipment in accordance with emission limitations, monitoring requirements and conditions set forth herein. This permit is issued in accordance with Title V of the Federal Clean Air Act (42 U.S.C.A. § 7401 - 7671) and the provisions of the Mississippi Air and Water Pollution Control Law (Section 49-17-1 et. seq., Mississippi Code of 1972), and the regulations and standards adopted and promulgated thereunder.

Permit Issued: December 31, 2020

Effective Date: As specified herein.

MISSISSIPPI ENVIRONMENTAL QUALITY PERMIT BOARD

Krystal Rudolph

AUTHORIZED SIGNATURE
MISSISSIPPI DEPARTMENT OF ENVIRONMENTAL QUALITY

Expires: November 30, 2025 **Permit No.: 1280-00090**

1321 PER20120001

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SECTION 1. GENERAL CONDITIONS

1.1 The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Federal Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(6)(a).)

1.2 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.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(6)(b).)

1.3 This permit and/or any part thereof 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.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(6)(c).)

1.4 Prior to its expiration, this permit may be reopened in accordance with the provisions listed below.

(a) This permit shall be reopened and revised under any of the following circumstances:

(1) Additional applicable requirements under the Federal Act become applicable to a major Title V source with a remaining permit term of 3 or more years. Such a reopening shall be completed no later than 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.

(2) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit.

(3) The Permit Board or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit.

(4) The Administrator or the Permit Board determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(b) Proceedings to reopen and issue this permit shall follow the same procedures as apply to initial permit issuance and shall only affect those parts of the permit for which

cause to reopen exists. Such reopening shall be made as expeditiously as practicable.

(c) Reopenings shall not be initiated before a notice of such intent is provided to the Title V source by the DEQ at least 30 days in advance of the date that the permit is to be reopened, except that the Permit Board may provide a shorter time period in the case of an emergency.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.4.G.)

1.5 The permittee shall furnish to the DEQ within a reasonable time any information the DEQ 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 DEQ copies of records required to be kept by the permittee or, for information to be confidential, the permittee shall furnish such records to DEQ along with a claim of confidentiality. The permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(6)(e).)

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

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(6)(d).)

1.7 The provisions of this permit are severable. If any provision of this permit, or the application of any provision of this permit to any circumstances, is challenged or held invalid, the validity of the remaining permit provisions and/or portions thereof or their application to other persons or sets of circumstances, shall not be affected thereby.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(5).)

1.8 The permittee shall pay to the DEQ an annual permit fee. The amount of fee shall be determined each year based on the provisions of regulated pollutants for fee purposes and the fee schedule specified in the Commission on Environmental Quality's order which shall be issued in accordance with the procedure outlined in Regulation 11 Miss. Admin. Code Pt. 2, Ch. 6.

(a) For purposes of fee assessment and collection, the permittee shall elect for actual or allowable emissions to be used in determining the annual quantity of emissions unless the Commission determines by order that the method chosen by the applicant for calculating actual emissions fails to reasonably represent actual emissions. Actual emissions shall be calculated using emission monitoring data or direct emissions measurements for the pollutant(s); mass balance calculations such as the amounts of the pollutant(s) entering and leaving process equipment and where mass balance calculations can be supported by direct measurement of process parameters, such direct measurement data shall be supplied; published emission factors such as those relating release quantities to throughput or equipment type (e.g., air emission factors);

or other approaches such as engineering calculations (e.g., estimating volatilization using published mathematical formulas) or best engineering judgments where such judgments are derived from process and/or emission data which supports the estimates of maximum actual emission.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.6.A(2).)

(b) If the Commission determines that there is not sufficient information available on a facility's emissions, the determination of the fee shall be based upon the permitted allowable emissions until such time as an adequate determination of actual emissions is made. Such determination may be made anytime within one year of the submittal of actual emissions data by the permittee.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.6.A(2).)

(c) If at any time within the year the Commission determines that the information submitted by the permittee on actual emissions is insufficient or incorrect, the permittee will be notified of the deficiencies and the adjusted fee schedule. Past due fees from the adjusted fee schedule will be paid on the next scheduled quarterly payment time.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.6.D(2).)

(d) The fee shall be due September 1 of each year. By July 1 of each year, the permittee shall submit an inventory of emissions for the previous year on which the fee is to be assessed. The permittee may elect a quarterly payment method of four (4) equal payments; notification of the election of quarterly payments must be made to the DEQ by the first payment date of September 1. The permittee shall be liable for penalty as prescribed by State Law for failure to pay the fee or quarterly portion thereof by the date due.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.6.D.)

(e) If in disagreement with the calculation or applicability of the Title V permit fee, the permittee may petition the Commission in writing for a hearing in accordance with State Law. Any disputed portion of the fee for which a hearing has been requested will not incur any penalty or interest from and after the receipt by the Commission of the hearing petition.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.6.C.)

1.9 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 this permit.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(8).)

1.10 Any document required by this permit to be submitted to the DEQ shall contain a certification by a 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.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.2.E.)

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

(a) enter upon the permittee's premises where a Title V 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 any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

(d) as authorized by the Federal Act, sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.C(2).)

1.12 Except as otherwise specified or limited herein, the permittee shall have necessary sampling ports and ease of accessibility for any new air pollution control equipment, obtained after May 8, 1970, and vented to the atmosphere.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.I(1).)

1.13 Except as otherwise specified or limited herein, the permittee shall provide the necessary sampling ports and ease of accessibility when deemed necessary by the Permit Board for air pollution control equipment that was in existence prior to May 8, 1970.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.I(2).)

1.14 Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance where such applicable requirements are included and are specifically identified in the permit or where the permit contains a determination, or summary thereof, by the Permit Board that requirements specifically identified previously are not applicable to the source.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.F(1).)

1.15 Nothing in this permit shall alter or affect the following:

(a) the provisions of Section 303 of the Federal Act (emergency orders), including the authority of the Administrator under that section;

(b) 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;

(c) the applicable requirements of the acid rain program, consistent with Section 408(a) of the Federal Act.

(d) the ability of EPA to obtain information from a source pursuant to Section 114 of the Federal Act.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.F(2).)

1.16 The permittee shall comply with the requirement to register a Risk Management Plan if permittee's facility is required pursuant to Section 112(r) of the Act to register such a plan.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.H.)

1.17 Expiration of this permit terminates the permittee's right to operate unless a timely and complete renewal application has been submitted. A timely application is one which is submitted at least six (6) months prior to expiration of the Title V permit. If the permittee submits a timely and complete application, the failure to have a Title V permit is not a violation of regulations until the Permit Board takes final action on the permit application. This protection shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit by the deadline specified in writing by the DEQ any additional information identified as being needed to process the application.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.4.C(2)., R. 6.4.B., and R. 6.2.A(1)(c).)

1.18 The permittee is authorized to make changes within their facility without requiring a permit revision (ref: Section 502(b)(10) of the Act) if:

(a) the changes are not modifications under any provision of Title I of the Act;

(b) the changes do not exceed the emissions allowable under this permit;

(c) the permittee provides the Administrator and the Department with written notification in advance of the proposed changes (at least seven (7) days, or such other time frame as provided in other regulations for emergencies) and the notification includes:

(1) a brief description of the change(s),

(2) the date on which the change will occur,

(3) any change in emissions, and

(4) any permit term or condition that is no longer applicable as a result of the change;

(d) the permit shield shall not apply to any Section 502(b)(10) change.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.4.F(1).)

1.19 Should the Executive Director of the Mississippi Department of Environmental Quality declare an Air Pollution Emergency Episode, the permittee will be required to operate in accordance with the permittee's previously approved Emissions Reduction Schedule or, in the absence of an approved schedule, with the appropriate requirements specified in 11 Miss. Admin. Code Pt. 2, Ch. 3., "Regulations for the Prevention of Air Pollution Emergency Episodes" for the level of emergency declared.

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 3.)

1.20 Except as otherwise provided herein, a modification of the facility may require a Permit to Construct in accordance with the provisions of Regulations 11 Miss. Admin. Code Pt. 2, Ch. 2., "Permit Regulations for the Construction and/or Operation of Air Emissions Equipment", and may require modification of this permit in accordance with Regulations 11 Miss. Admin. Code Pt. 2, Ch. 6., "Air Emissions Operating Permit Regulations for the Purposes of Title V of the Federal Clean Air Act". Modification is defined as "[a]ny physical change in or change in the method of operation of a facility which increases the actual emissions or the potential uncontrolled emissions of any air pollutant subject to regulation under the Federal Act emitted into the atmosphere by that facility or which results in the emission of any air pollutant subject to regulation under the Federal Act into the atmosphere not previously emitted. A physical change or change in the method of operation shall not include:

(a) routine maintenance, repair, and replacement;

(b) use of an alternative fuel or raw material by reason of an order under Sections 2 (a) and (b) of the Federal Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(c) use of an alternative fuel by reason of an order or rule under Section 125 of the Federal Act;

(d) use of an alternative fuel or raw material by a stationary source which:

(1) the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51, Subpart I, or 40 CFR 51.166; or

(2) the source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Part 51, Subpart I, or 40 CFR 51.166;

(e) an increase in the hours of operation or in the production rate unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166; or

(f) any change in ownership of the stationary source.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.1.C(15).)

1.21 Any change in ownership or operational control must be approved by the Permit Board.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.4.D(4).)

1.22 This permit is a Federally approved operating permit under Title V of the Federal Clean Air Act as amended in 1990. All terms and conditions, including any designed to limit the source's potential to emit, are enforceable by the Administrator and citizens under the Federal Act as well as the Commission.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.B(1).)

1.23 Except as otherwise specified or limited herein, the open burning of residential, commercial, institutional, or industrial solid waste, is prohibited. This prohibition does not apply to infrequent burning of agricultural wastes in the field, silvicultural wastes for forest management purposes, land-clearing debris, debris from emergency clean-up operations, and ordnance. Open burning of land-clearing debris must not use starter or auxiliary fuels which cause excessive smoke (rubber tires, plastics, etc.); must not be performed if prohibited by local ordinances; must not cause a traffic hazard; must not take place where there is a High Fire Danger Alert declared by the Mississippi Forestry Commission or Emergency Air Pollution Episode Alert imposed by the Executive Director and must meet the following buffer zones.

(a) Open burning without a forced-draft air system must not occur within 500 yards of an occupied dwelling.

(b) Open burning utilizing a forced-draft air system on all fires to improve the combustion rate and reduce smoke may be done within 500 yards of but not within 50 yards of an occupied dwelling.

(c) Burning must not occur within 500 yards of commercial airport property, private airfields, or marked off-runway aircraft approach corridors unless written approval to conduct burning is secured from the proper airport authority, owner or operator.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.G.)

1.24 Except as otherwise specified herein, the permittee shall be subject to the following provision with respect to emergencies:

(a) Except as otherwise specified herein, 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 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.

(b) An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions specified in (c) following are met.

(c) The affirmative defense of emergency shall be demonstrated through properly signed contemporaneous operating logs, or other relevant evidence that include information as follows:

(1) an emergency occurred and that the permittee can identify the cause(s) of the emergency;

(2) the permitted facility was at the time being properly operated;

(3) 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

(4) the permittee submitted notice of the emergency to the DEQ within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(d) In any enforcement proceeding, the permittee seeking to establish the occurrence of

an emergency has the burden of proof.

(e) This provision is in addition to any emergency or upset provision contained in any applicable requirement specified elsewhere herein.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.G.)

1.25 Except as otherwise specified herein, the permittee shall be subject to the following provisions with respect to upsets, startups, and shutdowns.

(a) Upsets (as defined in 11 Miss. Admin. Code Pt. 2, R. 1.2.)

(1) For an upset, the Commission may pursue an enforcement action for noncompliance with an emission standard or other requirement of an applicable rule, regulation, or permit. In determining whether to pursue enforcement action, and/or the appropriate enforcement action to take, the Commission may consider whether the source has demonstrated through properly signed contemporaneous operating logs or other relevant evidence the following:

(i) An upset occurred and that the source can identify the cause(s) of the upset;

(ii) The source was at the time being properly operated;

(iii) During the upset the source took all reasonable steps to minimize levels of emissions that exceeded the emission standard or other requirement of an applicable rule, regulation, or permit;

(iv) That within 5 working days of the time the upset began, the source submitted a written report to the Department describing the upset, the steps taken to mitigate excess emissions or any other noncompliance, and the corrective actions taken and;

(v) That as soon as practicable but no later than 24 hours of becoming aware of an upset that caused an immediate adverse impact to human health or the environment beyond the source boundary or caused a general nuisance to the public, the source provided notification to the Department.

(2) In any enforcement proceeding by the Commission, the source seeking to establish the occurrence of an upset has the burden of proof.

(3) This provision is in addition to any upset provision contained in any applicable requirement.

(4) These upset provisions apply only to enforcement actions by the Commission and are not intended to prohibit EPA or third party enforcement actions.

(b) Startups and Shutdowns (as defined in 11 Miss. Admin. Code Pt. 2, R. 1.2.)

(1) Startups and shutdowns are part of normal source operation. Emission limitations apply during startups and shutdowns unless source specific emission limitations or work practice standards for startups and shutdowns are defined by an applicable rule, regulation, or permit.

(2) Where the source is unable to comply with existing emission limitations established under the State Implementation Plan (SIP) and defined in this regulation, 11 Mississippi Administrative Code, Part 2, Chapter 1, the Department will consider establishing source specific emission limitations or work practice standards for startups and shutdowns. Source specific emission limitations or work practice standards established for startups and shutdowns are subject to the requirements prescribed in 11 Miss. Admin. Code Pt. 2, R. 1.10.B(2)(a) through (e).

(3) Where an upset as defined in Rule 1.2 occurs during startup or shutdown, see the upset requirements above.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.10.)

1.26 The permittee shall comply with all applicable standards for demolition and renovation activities pursuant to the requirements of 40 CFR Part 61, Subpart M, as adopted by reference in Regulation 11 Miss Admin. Code Pt. 2, R. 1.8. The permittee shall not be required to obtain a modification of this permit in order to perform the referenced activities.

(Ref.: 11 Miss Admin. Code Pt. 2, R. 1.8.)

SECTION 2. EMISSION POINTS & POLLUTION CONTROL DEVICES

Emission Point	Description
AA-001	5,460.5 MMBtu/hr (nominal) Combustion Engineering Tangentially-Fired Utility Boiler equipped with low-NO_x burners, an electrostatic precipitator for control of PM, a flue gas desulfurization (FGD) system for control of SO_2, and an Activated Carbon Injection (ACI) system for the control of Mercury. The boiler is permitted to combust coal (bituminous and subbituminous), #2 fuel oil, used oil, natural gas, petroleum contaminated soil, boiler cleaning waste, and wood waste. Emissions are typically routed through the FGD stack; however, exhaust gases may be routed through a bypass stack during upsets and emergency situations. (Ref.: Plant Daniel Unit 1)
AA-002	5,460.5 MMBtu/hr (nominal) Combustion Engineering Tangentially-Fired Utility Boiler equipped with low-NO_x burners, an electrostatic precipitator for control of PM, a flue gas desulfurization (FGD) system for control of SO_2, and an Activated Carbon Injection (ACI) system for the control of Mercury. The boiler is permitted to combust coal (bituminous and subbituminous), #2 fuel oil, used oil, natural gas, petroleum contaminated soil, boiler cleaning waste, and wood waste. Emissions are typically routed through the FGD stack; however, exhaust gases may be routed through a bypass stack during upsets and emergency situations. (Ref.: Plant Daniel Unit 2)
AA-003	1,946 MMBtu/hr (nominal) Combustion Turbine (CT) equipped with dry, low NO_x burners and a 159 MMBtu/hr (LHV) Coen duct burner heat recovery steam generator (HRSG). Both combustion devices burn natural gas only. The unit uses selective catalytic reduction (SCR) to control NO_x emissions. Unit 3 is a combined-cycle comprised of two CT/HRSGs that supply steam to a single steam turbine. (Ref.: Plant Daniel Unit 3a)
AA-004	1,946 MMBtu/hr (nominal) Combustion Turbine (CT) equipped with dry, low NO_x burners and a 159 MMBtu/hr (LHV) Coen duct burner heat recovery steam generator (HRSG). Both combustion devices burn natural gas only. The unit uses selective catalytic reduction (SCR) to control NO_x emissions. Unit 3 is a combined-cycle comprised of two CT/HRSGs that supply steam to a single steam turbine. (Ref.: Plant Daniel Unit 3b)
AA-005	1,946 MMBtu/hr (nominal) Combustion Turbine (CT) equipped with dry, low NO_x burners and a 159 MMBtu/hr (LHV) Coen duct burner heat recovery steam generator (HRSG). Both combustion devices burn natural gas only. The unit uses selective catalytic reduction (SCR) to control NO_x emissions. Unit 4 is a combined-cycle comprised of two CT/HRSGs that supply steam to a single steam turbine. (Ref.: Plant Daniel Unit 4a)
AA-006	1,946 MMBtu/hr (nominal) Combustion Turbine (CT) equipped with dry, low NO_x burners and a 159 MMBtu/hr (LHV) Coen duct burner heat recovery steam generator (HRSG). Both combustion devices burn natural gas only. The unit uses selective catalytic reduction (SCR) to control NO_x emissions. Unit 4 is a combined-cycle comprised of two CT/HRSGs that supply steam to a single steam turbine. (Ref.: Plant Daniel Unit 4b)
AA-020	Fugitive emissions from the conveying and crushing of coal
AA-021	Fugitive emissions from the bulldozing, hauling, and storage (piles) of coal
AA-030	Limestone storage silo equipped with a baghouse for Unit 1 FGD system process line
AA-032	Limestone slurry mixing tank equipped with a venturi scrubber for Unit 1 FGD system process line
AA-034	Activated carbon storage silo equipped with bin vent filters
AA-035	Activated carbon storage silo equipped with bin vent filters
AA-039	6.0 MMBtu/hr natural gas-fired process heater

Emission Point	Description
AE-001	983 HP (6.759 MMBtu/hr, 650 kW) diesel-fired emergency engine for the service building (Model Yr. 2019)
AE-002	546 HP (3.961 MMBtu/hr, 350 kW) diesel-fired emergency engine for the Gypsum Sedimentation Pond (Model Yr. 2013)
AE-003	1,214 HP (7.936 MMBtu/hr, 800 kW) diesel-fired emergency generator for the Gypsum Booster Station (Model Yr. 2013)
AE-004	365 HP (1.939 MMBtu/hr, 272 kW) diesel-fired emergency fire pump for the FGD system (Model Yr. 2014)
AE-005	365 HP (1.994 MMBtu/hr, 272.2 kW) diesel-fired emergency fire pump for Unit 2 (Model Yr. 2012)
AE-006	258 HP (8.792 MMBtu/hr, 315 kW) diesel-fired emergency generator for Unit 3 (Model Yr. 2009)
AE-007	258 HP (8.792 MMBtu/hr, 315 kW) diesel-fired emergency generator for Unit 4 (Model Yr. 2009)
AE-008	293 HP (1.6266 MMBtu/hr, 219 kW) diesel-fired emergency fire pump for Unit 1 (Model Yr. 2004)
AE-009	685 HP (4.792 MMBtu/hr, 511 kW) diesel-fired emergency generator for Units 1 and 2 (Model Yr. 2006/Mfd. Date 2/2006)

SECTION 3. EMISSION LIMITATIONS & STANDARDS

A. Facility-Wide Emission Limitations & Standards

3.A.1 Except as otherwise specified or limited herein, the permittee shall not cause, permit, or allow the emission of smoke from a point source into the open air from any manufacturing, industrial, commercial or waste disposal process which exceeds forty (40) percent opacity subject to the exceptions provided in (a) & (b).

(a) Startup operations may produce emissions which exceed 40% opacity for up to fifteen (15) minutes per startup in any one hour and not to exceed three (3) startups per stack in any twenty-four (24) hour period.

(b) Emissions resulting from soot blowing operations shall be permitted provided such emissions do not exceed 60 percent opacity, and provided further that the aggregate duration of such emissions during any twenty-four (24) hour period does not exceed ten (10) minutes per billion BTU gross heating value of fuel in any one hour.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.A.)

3.A.2 Except as otherwise specified or limited herein, the permittee shall not cause, allow, or permit the discharge into the ambient air from any point source or emissions, any air contaminant of such opacity as to obscure an observer's view to a degree in excess of 40% opacity, equivalent to that provided in Condition 3.A.1. This shall not apply to vision obscuration caused by uncombined water droplets.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.B.)

3.A.3 The permittee shall not cause, permit, or allow the emission of particles or any contaminants in sufficient amounts or of such duration from any process as to be injurious to humans, animals, plants, or property, or to be a public nuisance, or create a condition of air pollution.

(a) The permittee shall not cause or permit the handling, transporting, or storage of any material in a manner which allows or may allow unnecessary amounts of particulate matter to become airborne.

(b) When dust, fumes, gases, mist, odorous matter, vapors, or any combination thereof escape from a building or equipment in such a manner and amount as to cause a nuisance to property other than that from which it originated or to violate any other provision of 11 Miss. Admin. Code Pt. 2, Ch. 1, the Commission may order such corrected in a way that all air and gases or air and gasborne material leaving the building or equipment are controlled or removed prior to discharge to the open air.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.C.)

B. Emission Point Specific Emission Limitations & Standards

Emission Point(s)	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limit/Standard
AA-001 AA-002	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the TVOP issued February 4, 2000, and modified June 27, 2003	3.B.1	Alternative Fuel Usage	
			Used oil	≤ 12,000 gallons in each unit per year (rolling 12-month total)
			Petroleum contaminated soil	Fed with coal at a rate ≤ 200 lbs/ton of coal and not to exceed a total of 300 tons/day
			Non-hazardous boiler cleaning wastes	≤ 1,000,000 gallons/year (rolling 12-month total)
			Clean wood products	≤ 20% of the total fuel usage
AA-001 AA-002	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the PSD Construction Permits issued October 8, 2008, and January 4, 2010	3.B.2	CO	0.153 lbs/MMBtu (3-hour average) and 3,660 tons/year
AA-001 AA-002	11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(b).	3.B.3	PM (filterable only)	$E = 0.8808*I^{-0.1667}$
	11 Miss. Admin. Code Pt. 2, R. 1.4.A(1).	3.B.4	SO_2	4.8 lbs/MMBtu
AA-001 AA-002	40 CFR 60, Subpart D Standards of Performance for Fossil Fuel Fired Steam Generators 40 CFR 60.40, Subpart D	3.B.5	PM (filterable only) SO_2 NO_x Opacity	Applicability
	40 CFR 60.42(a)(1), Subpart D	3.B.6	PM (filterable only)	0.10 lbs/MMBtu (3-hour average)
	40 CFR 60.42(a)(2), Subpart D	3.B.7	Opacity	≤ 20%, except for one 6-minute period per hour of not more than 27%
	40 CFR 60.43(a)(2) and (b), Subpart D	3.B.8	SO_2	1.2 lbs/MMBtu heat input when firing coal alone or with wood residue **OR** ≤ ng/J value obtained from equation in condition when firing a combination of fuels (rolling 3-hour average)
	40 CFR 60.44(a)(3) and (b), Subpart D	3.B.9	NO_x	0.70 lbs/MMBtu heat input when firing coal alone or with wood residue **OR** ≤ ng/J value obtained from equation in condition when firing a combination of

Emission Point(s)	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limit/Standard
				fuels (rolling 3-hour average)
AA-001 AA-002	40 CFR 63, Subpart UUUUU NESHAP: Coal and Oil Fired Electric Utility Steam Generating Units 40 CFR 63.9980, 63.9981, 63.9982(a)(1) and (d), and 63.9990(a)(1), Subpart UUUUU	3.B.10	HAP	Applicability
	63.9991(a)(1) and (c), 63.10000(a) and (b), and Table 2, Subpart UUUUU	3.B.11	PM (filterable only) for HAP metals	0.03 lbs/MMBtu (input based) **OR** 0.3 lbs/MWh (output based)
			SO_2 for HCl	0.20 lbs/MMBtu (input based) **OR** 1.5 lbs/MWh (output based) (rolling 30-boiler operating day average)
			Hg	1.2 lbs/TBtu (input based) **OR** 0.013 lbs/GWh (output based) (rolling 30-boiler operating day average)
AA-003 AA-004 AA-005 AA-006	11 Miss. Admin. Code Pt. 2, R. 2.15.C., as established in the Title V Operating Permit issued February 4, 2000 and modified June 27, 2003	3.B.12	Startup and Shutdown	Definition of startup and shutdown
AA-003 AA-004 AA-005 AA-006	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the PSD Construction Permit issued December 31, 1998, and modified in TVOP issued February 4, 2000	3.B.13	PM/PM_{10} (filterable only)	0.011 lbs/MMBtu not to exceed 22.0 lbs/hr (3-hour average) and 96.36 tons/year (12-month total)
			NO_x	0.013 lbs/MMBtu not to exceed 27.4 lbs/hr (3-hour average) and 120 tons/year (12-month total)
			CO	0.057 lbs/MMBtu not to exceed 119.5 lbs/hr (3-hour average) and 523.41 tons/year (12-month total)
			VOC	0.015 lbs/MMBtu not to exceed 30.3 lbs/hr (3-hour average) and 132.71 tons/year (12-month total)
			Opacity	$\leq$ 10%
			Fuel restriction	Limited to natural gas only
AA-003 AA-004	11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(b).	3.B.3	PM (filterable only)	$E = 0.8808*I^{-0.1667}$

Emission Point(s)	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limit/Standard
AA-005 AA-006				
AA-003 AA-004 AA-005 AA-006 (duct burners)	40 CFR 60, Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units 40 CFR 60.40b(a) and (i), Subpart Db	3.B.14	SO_2 PM NO_x	Applicability
	40 CFR 60.42b(k)(2), Subpart Db	3.B.15	SO_2	Exemption from SO_2 emission limit
	40 CFR 60.44b(l)(1), (h), and (i), Subpart Db	3.B.16	NO_x	0.20 lbs/MMBtu heat input (30-day rolling average)
AA-003 AA-004 AA-005 AA-006 (combustion turbines)	40 CFR 60, Subpart GG Standards of Performance for Stationary Gas Turbines 40 CFR 60.330, Subpart GG	3.B.17	NO_x SO_2	Applicability
	40 CFR 60.332(a)(1) and (b), Subpart GG	3.B.18	NO_x	STD = 0.0075*(14.4/Y) + F
	40 CFR 60.333(b), Subpart GG	3.B.19	SO_2	Fuel must contain less than 0.8% sulfur by weight
AA-003 AA-004 AA-005 AA-006 (combustion turbines)	40 CFR 63, Subpart YYYY NESHAP for Stationary Combustion Turbines 40 CFR 63.6080, 63.6085, and 63.6090(a)(1) and (b)(4), Subpart YYYY	3.B.20	HAP	Applicability
AA-030 AA-032	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the Permit to Construct issued December 7, 2011	3.B.21	Operating limit	Emissions routed to control device while operating
AA-034 AA-035	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the Permit to Construct issued June 6, 2014	3.B.22		

Emission Point(s)	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limit/Standard
AA-039	11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(a).	3.B.23	PM	0.6 lbs/MMBtu
AA-039	40 CFR 63, Subpart DDDDD NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR 63.7480, 63.7485, 63.7490(a) and (d), 63.7499(l), 63.7500(a)(3), and 63.7505(a), Subpart DDDDD	3.B.24	HAP	Applicability
AE-001 through AE-009	11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(a).	3.B.23	PM	0.6 lbs/MMBtu
AE-001 AE-002 AE-003 AE-004 AE-005 AE-006 AE-007 AE-008 AE-009	40 CFR 63, Subpart ZZZZ NESHAP for Stationary Reciprocating Internal Combustion Engines 40 CFR 63.6580, 63.6585, 63.6590(a)(1)(ii), (a)(2)(i), (a)(2)(ii), (b)(1)(i), and (c)(6), Subpart ZZZZ	3.B.25	HAP	Applicability
AE-008 AE-009	40 CFR 63.6640(f)(1) through (3), Subpart ZZZZ	3.B.26		Operating requirements
AE-001 AE-002 AE-003 AE-004 AE-005 AE-006 AE-007	40 CFR 60, Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines 40 CFR 60.4200(a)(2)(i) and (ii), Subpart IIII	3.B.27	$NMHC+NO_x$ CO PM (filterable only) SO_2	Applicability
AE-001 AE-003	40 CFR 60.4205(b), 60.4202(a)(2), and 60.4206, Subpart IIII, and 40 CFR 89.112(a), Subpart B	3.B.28	$NMHC + NO_x$ CO PM (filterable only)	6.4 g/kW-hr 3.5 g/kW-hr 0.20 g/kW-hr
AE-002 AE-006 AE-007		3.B.29	$NMHC + NO_x$ CO PM (filterable only)	4.0 g/kW-hr 3.5 g/kW-hr 0.20 g/kW-hr
AE-004	40 CFR 60.4205(c), 60.4206, and	3.B.30	$NMHC + NO_x$ CO	4.0 g/kW-hr 3.5 g/kW-hr

Emission Point(s)	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limit/Standard
AE-005	Table 4, Subpart IIII		PM (filterable only)	0.20 g/kW-hr
AE-001 AE-002 AE-003 AE-006 AE-007	40 CFR 60.4205(b) and 60.4202(a)(2), Subpart IIII, and 40 CFR 89.113(a), Subpart B	3.B.31	Opacity	≤20% during acceleration ≤15% during lugging mode ≤50% during the peaks in either acceleration or lugging mode
AE-001 AE-002 AE-003 AE-004 AE-005 AE-006 AE-007	40 CFR 60.4207(b), Subpart IIII and 40 CFR 80.510(b), Subpart I	3.B.32	SO_2 (Diesel fuel requirements)	Sulfur content of 15 ppm max **AND** Minimum cetane index of 40 **OR** maximum aromatic content of 35 volume percent
	40 CFR 60.4211(a)(1) through (3) and (c), Subpart IIII	3.B.33	$NMHC+NO_x$ CO PM (filterable only) SO_2	Certified engine requirements
	40 CFR 60.4211(f)(1), (2)(i), and (3), Subpart IIII	3.B.34		Operating requirements
AA-001 AA-002 AA-003 AA-004 AA-005 AA-006	40 CFR 72-78 Acid Rain Program Provisions 40 CFR 72.6, Subpart A	3.B.35	NO_x SO_2	Applicability
AA-001 AA-002 AA-003 AA-004 AA-005 AA-006	40 CFR 97, Subpart EEEEE Cross State Air Pollution Rule (CSAPR) NO_x Ozone Season Group 2 Trading Program 40 CFR 97.804, Subpart EEEEE	3.B.36	NO_x	Applicability

3.B.1 For Emission Points AA-001 and AA-002, the permittee is allowed to burn alternative fuels in accordance with the following:

(a) The permittee is authorized to burn a maximum of 12,000 gallons of non-hazardous waste oils in **each** unit per year that are generated during the production, transmission, and distribution of electricity.

(b) The permittee is authorized to burn petroleum contaminated soil fed with coal at a rate not to exceed 200 pounds per ton of coal, not to exceed a total of 300 tons per day. Contaminated soils shall not be brought in from other facilities and includes any clay-based petro-sorb used for the absorption of petroleum products (lube and fuel oils).

(c) The permittee is authorized to burn no more than 1,000,000 gallons per year of non-

hazardous boiler cleaning wastes that is collected during the routine cleaning of the boilers.

(d) The permittee is authorized to burn clean wood products as blends with coal with a maximum of 20 percent of the total fuel usage coming from the wood products in the fuel blend.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the TVOP issued February 4, 2000, and modified June 27, 2003)

3.B.2 For Emission Points AA-001 and AA-002, the permittee shall limit carbon monoxide (CO) emissions for **each** unit to less than 0.153 lbs/MMBtu (3-hr average) not to exceed 3,660 tons per year. The boilers shall be operated and maintained such that the best available control for CO is combustion control utilizing best combustion practices to maximize boiler combustion efficiency.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(10). , as established in the PSD Construction Permits issued October 8, 2008, and January 4, 2010)

3.B.3 For Emission Points AA-001, AA-002, AA-003, AA-004, AA-005, and AA-006, the permittee shall not have particulate emissions that exceed the emission rate as determined by the relationship:

$E = 0.8808*I^{-0.1667}$

where E is the emission rate in pounds per million BTU per hour heat input and I is the heat input in millions of BTU per hour.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(b).)

3.B.4 For Emission Points AA-001 and AA-002, the maximum discharge of sulfur oxides shall not exceed 4.8 pounds (measured as sulfur dioxide) per million BTU heat input.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.4.A(1).)

3.B.5 Emission Points AA-001 and AA-002 are subject to the applicable requirements of the Standards of Performance for Fossil Fuel Fired Steam Generators, 40 CFR 60, Subpart D, and the applicable requirements of the General Provisions, 40 CFR 60, Subpart A.

(Ref.: 40 CFR 60.40, Subpart D)

3.B.6 For Emission Points AA-001 and AA-002, the permittee shall not discharge into the atmosphere any gases that contain particulate matter (PM) in excess of 0.10 lbs/MMBtu as determined on a 3-hour average.

(Ref.: 40 CFR 60.42(a)(1), Subpart D)

3.B.7 For Emission Point AA-001 and AA-002, the permittee shall not discharge into the atmosphere any gases that exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(Ref.: 40 CFR 60.42(a)(2), Subpart D)

3.B.8 For Emission Point AA-001 and AA-002, the permittee shall not discharge into the atmosphere any gases that contain sulfur dioxide (SO_2) in excess of 1.2 lbs/MMBtu when firing coal alone or with wood residue. When firing different fossil fuels simultaneously in any combination, the applicable emission standard shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y\,(340) + z\,(520)}{(y + z)}$$

Where PS_{SO2} is the prorated standard for SO_2 when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired; y is the percentage of total heat input derived from liquid fossil fuel; and z is the percentage of total heat input derived from solid fossil fuel. Compliance with the applicable emission standard is determined on a rolling 3-hour average.

(Ref.: 40 CFR 60.43(a)(2) and (b) and 60.45(g)(2)(i), Subpart D)

3.B.9 For Emission Points AA-001 and AA-002, the permittee shall not discharge into the atmosphere any gases that contain nitrogen oxides (NO_x), expressed as NO_2, in excess of 0.70 lbs/MMBtu heat input when firing coal alone or with wood residue. When firing different fossil fuels simultaneously in any combination, the applicable emission standard shall be determined by proration using the following formula:

$$PS_{NO_x} = \frac{w\,(260) + x\,(86) + y\,(130) + z\,(300)}{(w + x + y + z)}$$

Where PS_{NOx} is the prorated standard for NO_x when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired; w is the percentage of total heat input derived from lignite; x is the percentage of total heat input derived from gaseous fossil fuel; y is the percentage of total heat input derived from liquid fossil fuel; and z is the percentage of total heat input derived from solid fossil fuel (except lignite).

(Ref.: 40 CFR 60.44(a)(3) and (b), Subpart D)

3.B.10 Emission Points AA-001 and AA-002 are subject to the applicable requirements of the National Emission Standards for Hazardous Air Pollutants: Coal and Oil Fired Electric Utility Steam Generating Units, 40 CFR 63, Subpart UUUUU, and the applicable General Provisions in 40 CFR 63, Subpart A.

(Ref.: 40 CFR 63.9980, 63.9981, 63.9982(a)(1) and (d), and 63.9990(a)(1), Subpart UUUUU)

3.B.11 For Emission Points AA-001 and AA-002, the permittee shall limit emissions in accordance with the following:

(a) PM emissions (filterable only) to 0.03 lbs/MMBtu (input based) **OR** 0.3 lbs/MWh (gross output);

(b) SO_2 emissions to 0.20 lbs/MMBtu (input based) **OR** 1.5 lbs/MWh (gross output)(rolling 30-boiler operating day average)

(c) Mercury (Hg) emissions to 1.2 lbs/TBtu (input based) OR 0.013 lbs/GWh (gross output) (rolling 30-boiler operating day average)

The permittee demonstrates compliance with the heat input based limits; however, upon approval by the DEQ, the permittee may demonstrate compliance with the output based limits for all or any of the pollutants. The permittee shall be in compliance with these emission limits at all times, except during periods of startup and shutdown. During startup or shutdown, the permittee shall comply with the work practice requirements contained in Section 3.D. The permittee shall operate and maintain each affected source, including the associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.

(Ref.: 40 CFR 63.9991(a)(1), 63.10000(a) and(b), and Table 2, Subpart UUUUU)

3.B.12 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall not use emissions generated during startup and shutdown to determine compliance with the short-term emission limits. However, emissions generated during these periods shall be included when determining compliance with the annual emission limits.

For purposes of this permit, startup is defined as bringing a unit into operation from a non-operative condition. Relative to fuel-burning equipment, a startup shall be construed to occur only when a unit is taken from a non-fired state to a fired state. A startup period shall end when the combustion turbine control indicates that Mode 6 operation has been achieved (greater than approximately 50% load). Startup is limited to eight (8) hours or less.

Shutdown is defined as the termination of operation of equipment. Relative to fuel-burning equipment, a shutdown shall be construed to occur only when a unit is taken from a fired to a non-fired state. A shutdown period will commence when the combustion turbine control indicates below Mode 6 operation (less than approximately 50% load).

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.15.C., as established in the Title V Operating Permit issued February 4, 2000 and modified June 27, 2003)

3.B.13 For Emission Points AA-003, AA-004, AA-005, and AA-006, the following emission and operating limits are applicable to each unit:

(a) PM/PM_{10} (filterable only) - less than 0.011 lbs/MMBtu not to exceed 22.0 lbs/hr (3-hour average) and 96.36 tons/year (12-month total);

(b) NO_x – less than 0.013 lbs/MMBtu not to exceed 27.4 lbs/hr (3-hour average) and 120 tons/year (12-month total);

(c) CO – 0.057 lbs/MMBtu not to exceed 119.5 lbs/hr (3-hour average) and 523.41 tons/year (12-month total);

(d) VOC – 0.015 lbs/MMBtu not to exceed 30.3 lbs/hr (3-hour average) and 132.71 tons/year (12-month total);

(e) Opacity – less than or equal to 10 percent; and

(f) Limited to burning natural gas only.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the PSD Construction Permit issued December 31, 1998, and modified in the TVOP issued February 4, 2000)

3.B.14 The duct burners associated with Emission Points AA-003, AA-004, AA-005, and AA-006 are subject to and shall comply with all applicable requirements of the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and the General Provisions, 40 CFR 60, Subpart A. Only the emissions resulting from the combustion of fuels in the duct burners are subject to the standards under Subpart Db.

(Ref.: 40 CFR 60.40b(a) and (i), Subpart Db)

3.B.15 The duct burners associated with Emission Points AA-003, AA-004, AA-005, and AA-006, are exempt from the SO_2 emissions limit since they are only permitted to burn natural gas which has a potential SO_2 emission rate of 0.32 lbs/MMBtu heat input or less.

(Ref.: 40 CFR 60.42b(k)(2), Subpart Db)

3.B.16 The duct burners associated with Emission Points AA-003, AA-004, AA-005, and AA-006, shall not discharge into the atmosphere any gases that contain NO_x (expressed as NO_2) in excess of 0.20 lbs/MMBtu heat input (rolling 30-day average). This standard applies to each unit at all times including periods of startup, shutdown, or malfunction.

(Ref.: 40 CFR 60.44b(l)(1), (h), and (i), Subpart Db)

3.B.17 The combustion turbines associated with Emission Points AA-003, AA-004, AA-005, and AA-006 are subject to and shall comply with the applicable requirements of the Standards of Performance for Stationary Gas Turbines, 40 CFR 60, Subpart GG and the General

Provisions, 40 CFR 60, Subpart A.

(Ref.: 40 CFR 60.330, Subpart GG)

3.B.18 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall not discharge into the atmosphere gases from any stationary turbine which contain nitrogen oxides in excess of the value obtained from the following equation:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where STD is the allowable ISO corrected NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis; Y is the manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4. kilojoules per watt hour; and F is the NO_x emission allowance for fuel-bound nitrogen as defined in 40 CFR 60.332(a)(4).

(Ref.: 40 CFR 60.332(a)(1) and (b), Subpart GG)

3.B.19 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall not burn any fuel which contains total sulfur in excess of 0.8 percent by weight (8,000 ppmw).

(Ref.: 40 CFR 60.333(b), Subpart GG)

3.B.20 Emission Points AA-003, AA-004, AA-005, and AA-006 are subject to and shall comply with the applicable requirements of the NESHAP for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY and the General Provisions, 40 CFR 63, Subpart A. Since these combustion turbines are considered existing sources under Subpart YYYY, they are not required to meet the requirements of Subparts YYYY or A per 40 CFR 63.6090(b)(4).

(Ref.: 40 CFR 63.6080, 63.6085, and 63.6090(a)(1) and (b)(4), Subpart YYYY)

3.B.21 For Emission Points AA-030 and AA-032, the permittee shall only operate the limestone storage silo when emissions are being routed to a baghouse (Emission Point AA-030) and the limestone slurry mix tank when emissions are being routed to a venturi scrubber (Emission Point AA-032).

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the Permit to Construct issued December 7, 2011)

3.B.22 For Emission Points AA-034 and AA-035, the activated carbon injection silo bin vents shall only be operated when emissions are being routed to bin vent filters.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(10)., as established in the Construction Permit

issued June 6, 2014)

3.B.23 For Emission Points AA-039 and AE-001 through AE-009, the maximum permissible emission of ash and/or particulate matter shall not exceed 0.6 pounds per million BTU per hour heat input.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(a).)

3.B.24 Emission Point AA-039 is subject to and shall comply with the applicable requirements of the NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD and the General Provisions, 40 CFR 63, Subpart A. For purposes of applicability to this subpart, the process heater is in the units designed to burn gas 1 fuels subcategory.

The permittee shall operate and maintain the boiler in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Subpart DDDDD work practice standards in Section 3.D of this permit apply at all times the unit is operating.

(Ref.: 40 CFR 63.7480, 63.7485, 63.7490(a) and (d), 63.7499(l), 63.7500(a)(3), and 63.7505(a), Subpart DDDDD)

3.B.25 Emission Points AE-001 through AE-009 are subject to and shall comply with all applicable requirements of the NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE), 40 CFR 63, Subpart ZZZZ and the General Provisions, 40 CFR 63, Subpart A.

For purposes of this subpart, Emission Point AE-008 is considered an existing, emergency, compression ignition (CI) stationary RICE with a site rating less than 500 HP at a major source of HAP emissions.

Emission Points AE-001, AE-002, AE-003, and AE-009 are considered new, emergency, CI stationary RICE with a site rating of more than 500 HP located at a major source of HAP emissions. Per 63.6590(b)(1)(i), new engines with a site rating in excess of 500 HP located at a major source of HAP emissions do not have to meet the requirements of Subparts ZZZZ or A. Emission Points AE-001, AE-002, and AE-003 are subject to the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII. However, Emission Point AE-009 is not subject to Subpart IIII since it was constructed prior to the Subpart IIII applicability date.

Emission Points AE-004, AE-005, AE-006, and AE-007 are considered new, emergency, CI stationary RICE with a site rating less than 500 HP located at a major source of HAP emissions. These engines shall meet the requirements of Subpart ZZZZ by complying with the applicable provisions of Subpart IIII.

(Ref.: 40 CFR 63.6580, 63.6585, 63.6590(a)(1)(ii), (a)(2)(i), (a)(2)(ii), (b)(1)(i), and (c)(6), Subpart ZZZZ)

3.B.26 Emission Points AE-008 and AE-009 shall be considered emergency stationary RICE under 40 CFR 63, Subpart ZZZZ provided the engines only operate in an emergency, during maintenance and testing, and during non-emergency situations for 50 hours per year as described in (c) below. If the permittee does not operate an engine according to the requirements in (a)-(c) below, the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines.

(a) There is no limit on the use of an engine during an emergency situation.

(b) The permittee may operate an engine for maintenance checks and readiness testing for a maximum of 100 hours per calendar year provided 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 insurance company associated with an engine. The permittee may petition the DEQ 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 the federal, state, or local standards require maintenance testing of an engine beyond 100 hours per calendar year.

(c) Emergency engines 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 (b). 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.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(10). and 40 CFR 63.6640(f)(1) through (3), Subpart ZZZZ)

3.B.27 Emission Points AE-001, AE-002, AE-003, AE-004, AE-005, AE-006, and AE-007 are subject to and shall comply with all applicable requirements of the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and the General Provisions, 40 CFR 60, Subpart A as specified in Table 8 of Subpart IIII. For purposes of this subpart, Emission Points AE-004 and AE-005 are considered fire pump engines.

(Ref.: 40 CFR 60.4200(a)(2)(i) and (ii), Subpart IIII)

3.B.28 For Emission Points AE-001 and AE-003, the permittee shall operate and maintain the engines such that they achieve the emission standards listed below for the life of the engine:

(a) NMHC + $NO_x \leq 6.4$ g/kW-hr

(b) CO ≤ 3.5 g/kW-hr

(c) PM (filterable only) ≤ 0.20 g/kW-hr

(Ref.: 40 CFR 60.4205(b), 60.4202(a)(2), and 60.4206, Subpart IIII and 40 CFR 89.112(a), Subpart B)

3.B.29 For Emission Points AE-002, AE-006, and AE-007, the permittee shall operate and maintain the engines such that they achieve the emission standards listed below for the life of the engine:

(a) NMHC + NO_x ≤ 4.0 g/kW-hr

(b) CO ≤ 3.5 g/kW-hr

(c) PM (filterable only) ≤ 0.20 g/kW-hr

(Ref.: 40 CFR 60.4205(b), 60.4202(a)(2), and 60.4206, Subpart IIII and 40 CFR 89.112(a), Subpart B)

3.B.30 For Emission Points AE-004 and AE-005, the permittee shall operate and maintain the engines such that they achieve the emission standards listed below for the life of the engine:

(a) NMHC + NO_x ≤ 4.0 g/kW-hr

(b) CO ≤ 3.5 g/kW-hr

(c) PM (filterable only) ≤ 0.20 g/kW-hr

(Ref.: 40 CFR 60.4205(c), 60.4206, and Table 4, Subpart IIII)

3.B.31 For Emission Points AE-001, AE-002, AE-003, AE-006, and AE-007, the permittee shall limit the opacity of the exhaust from each engine to the following:

(a) ≤ 20 percent during the acceleration mode;

(b) ≤ 15 percent during the lugging mode;

(c) ≤ 50 percent during the peaks in either acceleration or lugging mode.

(Ref.: 40 CFR 4205(b) and 60.4202(a)(2), Subpart IIII and 40 CFR 89.113(a), Subpart B)

3.B.32 For Emission Points AE-001, AE-002, AE-003, AE-004, AE-005, AE-006, and AE-007, the permittee shall use diesel fuel that meets the following per gallon standards:

(a) Maximum sulfur content of 15 ppm **AND**

(b) Minimum cetane index of 40 **OR** maximum aromatic content of 35 volume percent.

(Ref.: 40 CFR 60.4207(b), Subpart IIII and 40 CFR 80.510(b), Subpart I)

3.B.33 For Emission Points AE-001, AE-002, AE-003, AE-004, AE-005, AE-006, and AE-007, the permittee shall comply with the applicable emission standards by purchasing, installing,

operating, and maintaining engines that are certified to meet the applicable emission standards. The permittee shall operate and maintain the engines in accordance with the manufacturer's emission-related written instructions and can only change the emission-related settings that are permitted by the manufacturer.

(Ref.: 40 CFR 60.4211(a)(1) through (3), and (c), Subpart IIII)

3.B.34 For Emission Points AE-001, AE-002, AE-003, AE-004, AE-005, AE-006, and AE-007, the engines shall be considered emergency stationary RICE under 40 CFR 60, Subpart IIII provided the engines only operate in an emergency, during maintenance and testing, and during non-emergency situations for 50 hours per year as described in (c) below. If the permittee does not operate an engine in accordance with the requirements in (a)-(c) below, the engine will not be considered an emergency engine under Subpart IIII and it must then meet all applicable requirements for non-emergency engines.

(a) There is no limit on the use of the engine during an emergency situation.

(b) The permittee may operate the engines for maintenance checks and readiness testing for a maximum of 100 hours per calendar year provided 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 insurance company associated with the engines. The permittee may petition the DEQ 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 the federal, state, or local standards require maintenance testing of the engine beyond 100 hours per calendar year.

(c) The emergency engine 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 (b). Except as provided in 40 CFR 60.4211 (f)(3)(i), 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 to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(Ref.: 40 CFR 60.4211(f)(1), (2)(i), and (3), Subpart IIII)

3.B.35 Emission Points AA-001, AA-002, AA-003, AA-004, AA-005, and AA-006 are subject to the Acid Rain Program Requirements as specified in 40 CFR 72-78. The permittee shall comply with all applicable requirements of said standards as specified in the Acid Rain Permit attached to this permit in Appendix C.

(Ref.: 40 CFR 72.6, Subpart A)

3.B.36 Emission Points AA-001, AA-002, AA-003, AA-004, AA-005, and AA-006 are subject to the applicable requirements of the Cross State Air Pollution Rule (CSAPR) NO_x Ozone Season Group 2 Trading Program, 40 CFR 97, Subpart EEEEE and shall comply with the applicable provisions in Section 9.0 of this permit.

(Ref.: 40 CFR 97.804, Subpart EEEEE)

C. Insignificant and Trivial Activity Emission Limitations & Standards

Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limit/Standard
11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(a).	3.C.1	PM	0.6 lbs/MMBtu
11 Miss. Admin. Code Pt. 2, R. 1.4.A(1).	3.C.2	SO_2	4.8 lbs/MMBtu

3.C.1 The maximum permissible emission of ash and/or particulate matter from fossil fuel burning installations of less than 10 million BTU per hour heat input shall not exceed 0.6 pounds per million BTU per hour heat input.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.3.D(1)(a).)

3.C.2 The maximum discharge of sulfur oxides from any fuel burning installation in which the fuel is burned primarily to produce heat or power by indirect heat transfer shall not exceed 4.8 pounds (measured as sulfur dioxide) per million BTU heat input.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 1.4.A(1).)

D. Work Practice Standards

Emission Point(s)	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limit/Standard
AA-001 AA-002	40 CFR 63.10000(a) and (e), 63.10006(i)(1), 63.10021(e), and Table 3, Subpart UUUUU	3.D.1	HAP	Tune-up requirement
	40 CFR 63.10000(a) and (l) and Table 3, Subpart UUUUU	3.D.2		Startup and shutdown requirements
AA-039	40 CFR 63.7500(a)(1) and (e), 63.7510(g), 63.7515(d), 63.7540(a)(10)(i)-(vi) and (11), and Table 3, Subpart DDDDD	3.D.3	HAP	Biennial tune-up
AE-008	40 CFR 63.6602 and Table 2c, Subpart ZZZZ	3.D.4	HAP	Maintenance requirements
	40 CFR 63.6605(a) and (b), Subpart ZZZZ	3.D.5		General compliance requirements
	40 CFR 63.6625(e)(2) and (h), 63.6640(a), and Table 6, Subpart ZZZZ	3.D.6		Operating requirements

3.D.1 For Emission Points AA-001 and AA-002, the permittee shall conduct a tune-up of the electric utility steam generating unit (EGU) burner and combustion controls no more than 36

calendar months after the previous performance tune-up or 48 calendar months if neural network combustion optimization software is employed, as specified in 40 CFR 63.10021(e). If the EGU is offline when the deadline to perform a tune-up passes, the permittee shall perform the tune-up within thirty (30) days after the restart of the affected unit. Each tune-up shall consist of the following:

(a) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls, as necessary. Repair of a burner or combustion control equipment requiring special order parts may be scheduled as follows:

(1) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_x and CO must be installed within 3 calendar months after the burner inspection;

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

(b) 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;

(c) 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 affecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

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

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

(f) 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;

(g) 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). The permittee may use portable CO, NO_x and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(h) Maintain on-site and submit, if requested by the DEQ, an annual report containing the information in paragraphs (a) through (g) above and the following:

(1) 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;

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

(3) 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.

(Ref.: 40 CFR 63.10000(a) and (e), 63.10006(i)(1), 63.10021(e), and Table 3, Subpart UUUUU)

3.D.2 For Emission Points AA-001 and AA-002, the permittee shall comply with the following during periods of startup and shutdown:

Startup: The firing of fuel in a boiler after a shutdown 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). Any fraction of an hour in which startup occurs constitutes a full hour of startup.

(a) The permittee shall operate all CMS during startup. The permittee shall collect, record, report, and maintain appropriate data obtained from the monitoring system during startup.

(b) For startup of the unit, the permittee shall use clean fuels as defined in 40 CFR 63.10042 for ignition.

(c) Once the permittee starts firing coal, the permittee shall engage all of the applicable control technologies appropriately to comply with the relevant standards applicable during normal operation.

(d) The permittee shall keep records noted above during the startup periods and provide reports concerning activities and startup periods as specified in Condition 5.C.4.

Shutdown: The period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (i.e., heat or steam) or when no coal or liquid oil is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy and no fuel is being fired in the EGU. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.

(e) The permittee shall operate all CMS during shutdown, collect appropriate data, and calculate the pollutant emission rate for each hour of shutdown for those pollutants where a CMS is used.

(f) While firing coal during a shutdown, the permittee must vent emissions to the main stack and operate all applicable control devices and continue to operate those control devices after the cessation of coal 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 Subpart UUUUU and that require operation of the control devices.

(g) 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 40 CFR 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

(h) The permittee shall collect monitoring data and keep records during shutdown periods as specified above and submit reports as specified in Condition 5.C.4.

The permittee shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM during startup and shutdown periods.

(Ref.: 40 CFR 63.10000(a) and (l) and Table 3, Subpart UUUUU)

3.D.3 For Emission Point AA-039, the permittee shall conduct a tune-up biennially with each subsequent tune-up being completed no more than 25 months after the previous tune-up. Each tune-up shall consist of the following:

(a) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the burner inspection may be delayed 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 inspection, inspections are required only during planned entries into the storage vessel or process equipment;

(b) 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;

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

(d) 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;

(e) 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

(f) Maintain on-site and submit, if requested by DEQ, an annual report containing the concentrations of CO in the effluent stream in ppmv, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up; a description of any corrective actions taken as a part of the tune-up; and the type and amount of fuel used over the 12 months prior to the tune-up.

(Ref.: 40 CFR 63.7500(a)(1) and (e), 63.7510(g), 63.7515(d), 63.7540(a)(10)(i)-(vi) and (11), and Table 3, Subpart DDDDD)

3.D.4 For Emission Point AE-008, the permittee shall comply with the following requirements:

(a) Change oil and filter every 500 hours of operation or annually, whichever comes first or perform an oil analysis at the same frequency in order to extend the oil change requirement in accordance with 40 CFR 63.6625(i).

(b) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace when necessary.

(c) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace, as necessary.

If the engine is operating during an emergency and it is not possible to shut down the engine in order to perform the maintenance practice according to the schedule listed in (a)-(c) above, or if performing the maintenance practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The maintenance 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.

(Ref.: 40 CFR 63.6602 and Table 2c, Subpart ZZZZ)

3.D.5 For Emission Point AE-008, the permittee shall comply at all times with the applicable emission and operating limitations of 40 CFR 63, Subpart ZZZZ and operate and maintain the engines, including associated air pollution control 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 the permittee to make any further efforts to reduce emissions if levels required by Subpart ZZZZ have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the DEQ 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.

(Ref.: 40 CFR 63.6605(a) and (b), Subpart ZZZZ)

3.D.6 For Emission Point AE-008, the permittee shall operate and maintain the engine according to the manufacturer's emission-related written instructions or develop a 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 practices for minimizing emissions. The permittee shall minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

(Ref. 40 CFR 63.6625(e)(2) and (h), 63.6640(a) and Table 6, Subpart ZZZZ)

SECTION 4. COMPLIANCE SCHEDULE

4.1 Unless otherwise specified herein, the permittee shall be in compliance with all requirements contained herein upon issuance of this permit.

4.2 Except as otherwise specified herein, the permittee shall submit to the Permit Board and to the Administrator of EPA Region IV a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices, by January 31 for the preceding calendar year. Each compliance certification shall include the following:

(a) the identification of each term or condition of the permit that is the basis of the certification;

(b) the compliance status;

(c) whether compliance was continuous or intermittent;

(d) the method(s) used for determining the compliance status of the source, currently and over the applicable reporting period;

(e) such other facts as may be specified as pertinent in specific conditions elsewhere in this permit.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.C(5)(a), (c), & (d).)

SECTION 5. MONITORING, RECORDKEEPING & REPORTING REQUIREMENTS

A. General Monitoring, Recordkeeping and Reporting Requirements

5.A.1 The permittee shall install, maintain, and operate equipment and/or institute procedures as necessary to perform the monitoring and recordkeeping specified below.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3).)

5.A.2 In addition to the recordkeeping specified below, the permittee shall include with all records of required monitoring information the following:

(a) the date, place as defined in the 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 such analyses; and

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

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(b)(1).)

5.A.3 Except where a longer duration is specified in an applicable requirement, 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 the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(b)(2).)

5.A.4 Except as otherwise specified herein, the permittee shall submit reports of any required monitoring by July 31 and January 31 for the preceding six-month period. All instances of deviations from permit requirements must be clearly identified in such reports and all required reports must be certified by a responsible official consistent with 11 Miss. Admin. Code Pt. 2, R. 6.2.E.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1).)

5.A.5 Except as otherwise specified herein, the permittee shall report all deviations from permit requirements, including those attributable to upsets, the probable cause of such deviations, and any corrective actions or preventive measures taken. Said report shall be made within five (5) working days of the time the deviation began.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(2).)

5.A.6 Except as otherwise specified herein, the permittee shall perform emissions sampling and analysis in accordance with EPA Test Methods and with any continuous emission monitoring requirements, if applicable. All test methods shall be those versions, or their equivalents approved by the DEQ and the EPA.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3).)

5.A.7 The permittee shall maintain records of any alterations, additions, or changes in equipment or operation.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3).)

B. Specific Monitoring and Recordkeeping Requirements

Emission Point(s)	Applicable Requirement	Condition Number	Pollutant/ Parameter Monitored	Monitoring/Recordkeeping Requirement
AA-001 AA-002	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).	5.B.1	Fuel usage	Monitor and record fuel usage
	Permits to Construct issued October 9, 2008, and January 4, 2010, and 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).	5.B.2	CO	Biennial stack test
	PSD Construction Permit issued January 4, 2010 and 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).	5.B.3		Carbon Monoxide Emissions Minimization Protocol
AA-001 AA-002	40 CFR 60.45(a), Subpart D	5.B.4	Opacity SO_2 NO_x O_2/CO_2	Continuous monitoring
AA-001 AA-002	40 CFR 63.10000(c)(1)(i), (c)(1)(iii), and (c)(1)(i)(C)(2), 63.10005(h), 63.10006(b) and (f)(1)(iii), and Table 5, Subpart UUUUU	5.B.5	PM (filterable only) for HAP metal	Performance testing once every 3 years
	40 CFR 63.10000(c)(1)(v), 63.10007(a)(1), 63.10010(f), 63.10021(b), and Table 5, Subpart UUUUU	5.B.6	SO_2 for HCl	CEMS
	40 CFR 63.10000(c)(1)(vi), 63.10007(a)(1), 63.10010(g), 63.10021(b), and Table 5, Subpart UUUUU	5.B.7	Hg	
	40 CFR 63.10000(d) and 63.10020(a), Subpart UUUUU	5.B.8	PM SO_2 Hg	Site-specific monitoring plan and continuous monitoring
	40 CFR 63.10032(a) through (d) and (f) through (i), and 63.10033, Subpart UUUUU	5.B.9		Recordkeeping
AA-001 AA-002	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).	5.B.10	SO_2, NO_x	Monitoring of bypass events
AA-003 AA-004 AA-005 AA-006	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).	5.B.11	CO VOC	Biennial stack tests
		5.B.12	NO_x	CEMS
		5.B.13	Opacity	Visible emissions observations

Emission Point(s)	Applicable Requirement	Condition Number	Pollutant/ Parameter Monitored	Monitoring/Recordkeeping Requirement
AA-003 AA-004 AA-005 AA-006	40 CFR 60.46b(c) and (f)(2), 60.48b(b)(2), 60.49b(g) and (o)	5.B.14	NO_x	CEMS
	40 CFR 60.49b(d)(2), Subpart Db	5.B.15	Fuel usage	Maintain fuel usage records
AA-003 AA-004 AA-005 AA-006	40 CFR 60.334(c), Subpart GG	5.B.16	NO_x	CEMS
	40 CFR 60.334(h)(4), Subpart GG	5.B.17	SO_2	Custom fuel monitoring plan
AA-030 AA-032	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).	5.B.18	Opacity	Weekly visible emission observations
AA-034 AA-035	Construction Permit issued June 6, 2014	5.B.19	Opacity	Monthly visible emission observations
AE-008	40 CFR 63.6625(f) and 63.6655(f)(1), Subpart ZZZZ	5.B.20	HAP	Install non-resettable hour meter and record hours of operation
	40 CFR 63.6655(a)(1), (2), and (5) and (e)(2) and 63.6660, Subpart ZZZZ	5.B.21		General recordkeeping
AE-001 through AE-007	40 CFR 60.4209(a) and 60.4214(b), Subpart IIII	5.B.22	NMHC + NO_x, PM (filterable only), CO, SO_2	Install non-resettable hour meter and record hours of operation
AA-001 through AA-006	40 CFR 75.57(a), Subpart F	5.B.23	NO_x SO_2	General recordkeeping
AA-003 AA-004 AA-005 AA-006	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).	5.B.24	Startups and Shutdowns	General Recordkeeping

5.B.1 For Emission Points AA-001 and AA-002, the permittee shall keep monthly records of all fuels burned. These records shall consist of fuel type, quantity, the sulfur content (% by weight), and the heating value. The permittee shall also record and maintain the following information:

(a) Each time used oil is burned, the permittee shall perform a chemical analysis of the used oil and shall record the total amount of used oil fed to the boiler(s).

(b) The coal quality information shall be determined from vendor's data or by self-analysis. This information should include the percent sulfur, percent ash, heating value, and approximate tonnage received for each shipment of coal. The permittee is not required to supply such information for each individual car, barge, etc.; however, the information shall be supplied for each vendor's coal and each shipment the coal quality changes.

(c) The usage rate of wood materials that are blended with coal as fuel.

(d) The total quantity of petroleum contaminated soil burned in any given day and the feed rate of petroleum contaminated soil per ton of coal.

(e) The total quantity of boiler cleaning wastes burned.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.2 For Emission Points AA-001 and AA-002, the permittee shall demonstrate compliance with the CO emission limit biennially with a performance test using EPA Reference Method 7 or an approved equivalent. Stack testing shall be performed under normal operating conditions and while operating at or near capacity. All subsequent stack tests shall be conducted within 25 months of the previous test(s).

The permittee shall monitor and record the amount of fuel burned during the stack test(s) and report the heat input as MMBtu and report all emission results in units of lbs of CO/MMBtu heat input.

(Ref.: Permits to Construct issued October 9, 2008, and January 4, 2010, and 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.3 For Emission Point AA-001 and AA-002, the permittee shall operate in accordance with the Carbon Monoxide Emission Minimization Protocol contained in Appendix D to ensure continuous compliance with the CO emission limits.

(Ref.: PSD Construction Permit issued January 4, 2010, and 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.4 For Emission Points AA-001 and AA-002, the permittee shall install, calibrate, maintain, and operate continuous opacity monitoring systems (COMS) for measuring opacity and continuous emissions monitoring systems (CEMS) for measuring SO_2, NO_x, and either O_2 or CO_2.

(Ref.: 40 CFR 60.45(a), Subpart D)

5.B.5 For Emission Points AA-001 and AA-002, the permittee has demonstrated that the EGUs qualify as low emitting EGUs (LEE) for PM. As such, the permittee shall conduct subsequent performance tests once every three (3) years. These subsequent test(s) must be completed at least 1,050 calendar days after the end of the previous test date. If subsequent test results indicate an EGU does not meet the LEE eligibility requirements, the LEE status is lost, and the permittee shall resume quarterly emissions testing.

These units shall maintain the LEE status provided that, except for hours during which only clean fuel is combusted, the permittee bypasses the EGU control device only during

emergency periods for no more than a total of 2 percent of the EGU's annual operating hours; uses clean fuels to the maximum extent possible during an emergency period; and prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The permittee must include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status.

(Ref.: 40 CFR 63.10000(c)(1)(i), (c)(1)(iii), and (c)(1)(i)(C)(2), 63.10005(h), 63.10006(b) and (f)(1)(iii), and Table 5, Subpart UUUUU)

5.B.6 For Emission Points AA-001 and AA-002, the permittee shall install, certify, operate, and maintain a CEMS to monitor SO_2 emissions in accordance with 40 CFR 75 to demonstrate compliance with the SO_2 emissions limit. Quality assured CEMS data shall be collected for all unit operating conditions, including startup and shutdown; however, emissions rates determined during startup and shutdown periods are not to be included in compliance determinations.

(Ref.: 40 CFR 63.10000(c)(1)(v), 63.10007(a)(1), 63.10010(f), 63.10021(b), and Table 5, Subpart UUUUU)

5.B.7 For Emission Points AA-001 and AA-002, the permittee shall install, certify, operate, and maintain a CEMS to monitor Hg emissions in accordance with Appendix A of Subpart UUUUU to demonstrate compliance with the Hg emission limit. Quality assured CEMS data shall be collected for all unit operating conditions, including startup and shutdown; however, emission rates determined during startup and shutdown periods are not to be included in compliance determinations.

(Ref.: 40 CFR 63.10000(c)(1)(vi), 63.10007(a)(1), 63.10010(g), 63.10021(b), and Table 5, Subpart UUUUU)

5.B.8 For Emission Points AA-001 and AA-002, the permittee shall develop a site-specific monitoring plan in accordance with 40 CFR 63.10000 and shall address the following:

(a) Installation of the CMS (CEMS or CPMS) sampling probe or other interface at a measurement location relative to each EGU such that the measurement is representative of control of the exhaust emissions.

(b) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(c) Schedule for conducting periodic performance evaluations.

(d) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

(e) On-going operation and maintenance procedures, in accordance with 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(f) Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out-of-control periods consistent with 63.8(c)(7)(ii) and (c)(8).

(g) On-going recordkeeping and reporting procedures in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under Subpart UUUUU.

(Ref.: 40 CFR 63.10000(d) and 63.10020(a), Subpart UUUUU)

5.B.9 For Emission Points AA-001 and AA-002, the permittee shall keep the following records, as applicable:

(a) A copy of each notification and report submitted to comply with Subpart UUUUU.

(b) Records of performance stack tests, fuel analyses, or other compliance demonstration and performance evaluation.

(c) For each CEMS and CPMS, the following shall be kept:

(1) The records described in 40 CFR 63.10(b)(2)(vi) through (xi);

(2) Previous version of the performance evaluation plan as required in 40 CFR 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i); and

(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.

(d) For each EGU, the permittee shall keep the following records:

(1) Records of monthly fuel use by each EGU, including the type(s) and amounts used.

(2) Annual records that document that the emissions in the previous stack test(s) continue to qualify the EGUs for LEE status for PM and document that there was no change in source operations including fuel consumption and operation of air pollution control equipment that would cause emission of the pollutant to increase within the past year.

(e) For startup or shutdown periods, keep records of the occurrence and duration of each startup and shutdown.

(f) Records of the occurrence and duration of each malfunction of an operation or the air

pollution control and monitoring equipment.

(g) Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition 3.B.11, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(h) Records of the type(s) and amount(s) of fuel used during each startup or shutdown.

These records shall be kept in a form suitable and readily available for expeditious review for a period of five (5) years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. These records must be kept on site for at least two (2) years and then off-site for the remaining three (3) years.

(Ref.: 40 CFR 63.10032(a) through (d) and (f) through (i), and 63.10033, Subpart UUUUU)

5.B.10 For Emission Points AA-001 and AA-002, the permittee shall keep records documenting the date, time, and duration for each instance in which emissions are routed through the bypass stack during an upset or emergency situation. This information shall also include a calculation of the SO_2 and NO_x emissions that occurred during each bypass event.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.11 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall demonstrate compliance with the CO and VOC emission limits by stack testing biennially in accordance with EPA Reference Methods 10 and 25, respectively, or an approved equivalent. All stack tests shall be completed under normal operating conditions and while operating at or near capacity. All subsequent tests shall be conducted within 25 months of the previous test(s).

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.12 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall demonstrate compliance with the NO_x emission limit in Condition 3.B.13 using the CEMS installed in accordance with the requirements of 40 CFR 75 and required by 40 CFR 60, Subparts Db and GG. The CEMS shall monitor and record the actual measured NO_x concentration in ppm and that value shall be used to calculate the lbs/MMBtu heat input and lbs/hr values.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.13 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall perform an annual Visible Emissions Evaluation (VEE) in accordance with EPA Reference Method 9. In years where the permittee is performing a stack test in accordance with Condition 5.B.11, the annual VEE shall be completed during the stack test.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.14 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall demonstrate compliance with the rolling 30-day average NO_x limit using a CEMS installed, certified, maintained, operated, and quality-assured for purposes of monitoring NO_x and CO_2 emissions in accordance with the requirements of 40 CFR 75.

The permittee shall also maintain the following records for each steam generating unit operating day, as applicable:

(a) Calendar date;

(b) The average hourly NO_x emission rates (expressed as NO_2) in ng/J or lbs/MMBtu heat input measured or predicted;

(c) The 30-day average NO_x emission rates in ng/J or lbs/MMBtu calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rated for the preceding 30 steam generating unit operating days;

(d) Identification of the steam generating unit operating days when the calculated 30-day average NO_x emission rates are in excess of the NO_x emission standards under Subpart Db with the reasons for such excess emissions as well as a description of corrective actions taken;

(e) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(f) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(g) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(h) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(i) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(j) Results of daily CEMS drift tests and quarterly accuracy assessments as required under 40 CFR 75, Appendix B and Appendix F

Data used to demonstrate compliance with Subpart Db shall not include any data substituted using the missing data or bias adjustment procedures of 40 CFR 75. All records required by Subpart Db shall be maintained for a period of two (2) years after the date of such record.

(Ref.: 40 CFR 60.46b(c) and (f)(2), 60.48b(b)(2), and 60.49b(g) and (o), Subpart Db)

5.B.15 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall record the amount of natural gas combusted in each unit each calendar month.

(Ref.: 40 CFR 60.49b(d)(2), Subpart Db)

5.B.16 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall use the CEMS installed to meet the requirements of 40 CFR 75 to meet the requirements of Subpart GG, except that the missing data substitution methodology provided for in 40 CFR 75, Subpart D is not required for purposes of identifying excess emissions for Subpart GG. Instead, these periods of missing data shall be considered monitor downtime.

(Ref.: 40 CFR 60.334(c), Subpart GG)

5.B.17 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall comply with the previously approved custom fuel monitoring plan contained in Appendix E of this permit.

(Ref.: 40 CFR 60.334(h)(4), Subpart GG)

5.B.18 For Emission Points AA-030 and AA-032, the permittee shall perform weekly visible emission observations in accordance with EPA Reference Method 22. If emissions are observed during the evaluation, the permittee shall immediately determine the reason for the visible emissions and take the necessary corrective action(s).

If there are no visible emissions observed for six (6) consecutive weeks, the frequency may be reduced to once per month. In the event visible emissions are detected during a monthly observation, the permittee shall return to weekly observations until such time no visible emissions are noted for six (6) consecutive weeks.

The results of all visible observations and any corrective actions, if necessary, shall be documented and available for review.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).)

5.B.19 For Emission Points AA-034 and AA-035, the permittee shall conduct monthly visual emission observations. The observations shall be conducted for at least one minute for each bin vent filter while materials are being unloaded to the silo. If any visible emissions are noted, the permittee shall immediately inspect the filter and determine the cause of the visible emissions and any corrective measures needed to eliminate the visible emissions. The permittee shall keep records identifying the emission point, date, time, results, and any corrective actions taken to eliminate visible emissions for each visible observation.

(Ref.: Construction Permit issued June 6, 2014)

5.B.20 For Emission Points AE-008 and AE-009, the permittee shall install a non-resettable hour meter on the engine, if one is not already installed. The permittee shall keep records of the hours of operation of the engine that are recorded through the hour meters. The permittee shall 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.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2). and 40 CFR 63.6625(f) and 63.6655(f)(1), Subpart ZZZZ)

5.B.21 For Emission Point AE-008, the permittee shall keep the following records:

(a) A copy of each notification and report submitted to comply with Subpart ZZZZ.

(b) Records of the occurrence and duration of each malfunction of an engine or hour meter.

(c) Records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore a malfunctioning engine or hour meter to its normal manner of operation.

(d) Records of the maintenance conducted on each engine in order to demonstrate the engines were operated and maintained in accordance to the maintenance plan.

All records shall be in a form suitable and ready for expeditious review for a period of five (5) years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. These records may be kept in an electronic or hard copy format.

(Ref.: 40 CFR 63.6655(a)(1), (2), and (5) and (e)(2) and 63.6660, Subpart ZZZZ)

5.B.22 For Emission Points AE-001 through AE-007, the permittee shall install a non-resettable hour meter on each engine, if one is not already installed. The permittee shall keep records of the operation of each engine in emergency and non-emergency service that are recorded through the hour meters. The permittee shall record the time of operation and the reason the engines were in operation during that time.

(Ref.: 40 CFR 60.4209(a) and 60.4214(b), Subpart IIII)

5.B.23 For Emission Points AA-001 through AA-006, the permittee shall monitor and keep records of emissions in accordance with 40 CFR 75. The permittee shall maintain a file on site of all measurements, data, reports, and other required information for each affected unit for a period of at least three (3) years from the date of each record.

(Ref.: 40 CFR 75.57(a), Subpart F)

5.B.24 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall monitor and keep records of the occurrence and duration of each startup and shutdown event.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(a)(2).))

C. Specific Reporting Requirements

Emission Point(s)	Applicable Requirement	Condition Number	Pollutant/ Parameter Monitored	Reporting Requirement
AA-001 AA-002	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1).	5.C.1	Fuel usage	Quarterly fuel usage report
		5.C.2	CO	Submit test protocols/test results
AA-001 AA-002	40 CFR 60.45(g), Subpart D	5.C.3	Opacity SO_2 NO_x	Excess emission and monitoring system performance report
AA-001 AA-002	40 CFR 63.10021(e)(9), and (g), 63.10031(a) through (e), (f)(4) and (6), and (g), and Table 8, Subpart UUUUU	5.C.4	PM SO_2 Hg	Reporting requirements
	40 CFR 63.100021(f) and 63.10031(f)(1) and (2), Subpart UUUUU	5.C.5		Electronic submittal of reports
AA-001 AA-002	40 CFR 75.64, Subpart G	5.C.6	SO_2, NO_x	Quarterly report
AA-003 AA-004 AA-005 AA-006	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c).	5.C.7	Opacity	Annual report
	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c).	5.C.2	PM/PM_{10} CO VOC	Submit test protocols/test results
AA-003 AA-004 AA-005 AA-006	40 CFR 60.49b(h)(2), (i), and (w) Subpart Db	5.C.8	NO_x	Excess emissions report
AA-003 AA-004 AA-005 AA-006	40 CFR 60.334(j), Subpart GG	5.C.9	NO_x SO_2	Excess emissions and monitor downtime reports
AA-030 AA-032 AA-034 AA-035	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c).	5.C.10	Opacity	Semiannual report
AE-008 AE-009	40 CFR 63.6640(b), 63.6650(f), and Footnote 1 to Table 2c, Subpart ZZZZ, and 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1).	5.C.11	Hours of operation	Semiannual report
AE-001 through	11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1)).	5.C.12	Hours of operation	Semiannual report

Emission Point(s)	Applicable Requirement	Condition Number	Pollutant/ Parameter Monitored	Reporting Requirement
AE-007				

5.C.1 For Emission Points AA-001 and AA-002, the permittee shall submit a quarterly fuel usage report that summarizes the quantity and type(s) of fuels burned during the reporting period. The summary reports are due within thirty days after the end of each calendar quarter. This information may be included with the semiannual reports required in Condition 5.A.4 for the second and fourth quarter reporting periods.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1).)

5.C.2 For Emission Points AA-001 through AA-006, the permittee shall submit the following notifications, information, and reports for each required performance test unless otherwise specified elsewhere:

(a) A notification of the scheduled test date(s) should be submitted ten (10) days prior to the scheduled date(s) so an observer may be afforded the opportunity to witness the test(s).

(b) A written test protocol for each required test at least thirty (30) days prior to the intended test date(s) to ensure all test methods and procedures are acceptable to the DEQ. After the first successful submittal of a written test protocol, the permittee may request that the submittal of the protocol be waived for subsequent testing by certifying in writing at least thirty (30) days prior to the subsequent testing that all conditions for testing remain unchanged such that the original protocol can and will be followed.

(c) Unless otherwise specified herein, the permittee shall submit all performance test results within sixty (60) days following completion of the performance test.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1).)

5.C.3 For Emission Points AA-001 and AA-002, the permittee shall submit semiannual excess emission and monitoring system performance reports in accordance with Condition 5.A.4. Each excess emissions and monitoring system performance report shall include all information required in 40 CFR 60.7(c). Periods of excess emissions and monitoring system downtime shall be reported as follows:

(a) For opacity, excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(b) For sulfur dioxide, excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour

periods) of SO_2 as measured by a CEMS exceed the applicable standard.

(c) For nitrogen oxides, excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standard.

(Ref.: 40 CFR 60.45(g), Subpart D)

5.C.4 For Emission Points AA-001 and AA-002, the permittee shall submit semiannual compliance reports in accordance with Condition 5.A.4 that contain the following:

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

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

(c) Indicate whether new types of fuel were burned during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use.

(d) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in Condition 3.D.1(f) and (g) were completed.

(e) The permittee must report emergency bypass information annually from EGUs with LEE status.

(f) 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 stack tests are being conducted once every 3 years to maintain LEE status, the date of each stack test conducted during the previous 3 years, a comparison of emission level achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold, and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(g) A certification.

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

(i) For each excess emissions event occurring at an affected source where a CMS is used to comply with the emission or operating limit, the permittee must include the information required in 40 CFR 63.10(e)(3)(v) in the compliance report.

(j) The permittee shall report all deviations of any emission or operating limit or work practice standard in the semiannual compliance report. Submission of this

information in the semiannual compliance report does not absolve the permittee from reporting deviations promptly as required in Condition 5.A.5. If there were no deviations during the reporting period, a statement of such shall be included in the report.

(k) The permittee shall report the number, duration, and a brief description for each type of malfunction that occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

(l) The permittee shall report the date, unit, duration, and emissions for each startup and shutdown.

Compliance reports shall be submitted electronically using EPA's Emissions Collection and Monitoring Plan System (ECMPS), as applicable.

(Ref.: 40 CFR 63.10021(e)(9) and (g), 63.10031(a) through (e), (f)(4) and (6), and (g), and Table 8, Subpart UUUUU)

5.C.5 For Emission Points AA-001 and AA-002, the permittee shall submit performance test reports and CEMS performance evaluations tests in accordance with the following:

(a) Performance Tests – within 60 days after the date of completing each performance test, the permittee shall submit the test report using EPA's ECMPS, as applicable.

(b) CEMS Performance Evaluation Tests – within 60 days after the date of completing each CEMS performance evaluation test, the permittee shall submit the relative accuracy test audit (RATA) data using EPA's ECMPS, as applicable.

(c) SO_2 and Hg CEMS – reports shall be submitted using the ECMPS Client Tool as provided for in Appendices A and B to Subpart UUUUU.

A hard copy of the information contained in these reports shall be submitted to the DEQ.

(Ref.: 40 CFR 63.10021(f) and 63.10031(f)(1) and (2), Subpart UUUUU)

5.C.6 For Emission Points AA-001 and AA-002, the permittee shall submit quarterly reports electronically that contain the emissions of SO_2 and NO_x that were emitted during the calendar quarter. This information shall include all emissions that occurred during an upset or malfunction in which emissions were routed through the bypass stack.

(Ref. 40 CFR 75.64, Subpart G)

5.C.7 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall submit the results of each VEE in the annual compliance report required by Condition 4.2.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c).)

5.C.8 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall submit semiannual reports in accordance with Condition 5.A.4 that contain a summary of the information recorded in Condition 5.B.14 (a) through (j).

(Ref.: 40 CFR 60.49b(h)(2), (i), and (w), Subpart Db)

5.C.9 For Emission Points AA-003, AA-004, AA-005, and AA-006, the permittee shall submit semiannual reports in accordance with Condition 5.A.4 that contain the following information concerning excess emissions or monitor downtime for all periods of unit operation, including startup, shutdown, and malfunction:

(a) *Nitrogen oxides*

(1) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_x concentration exceeds the applicable emission limit. For purposes of Subpart GG, a 4-hour rolling average NO_x concentration is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour.

(2) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NOx concentration or diluent (or both).

(3) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period. The permittee does not have to report ambient conditions if opting to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii) or if not using the ISO correction equation under 40 CFR 60.335(b)(1).

(b) *Sulfur Dioxide* – A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours and ends on the date and hour of the next valid sample.

(Ref.: 40 CFR 60.334(j), Subpart GG)

5.C.10 For Emission Points AA-030, AA-032, AA-034, and AA-035, the permittee shall submit a report containing a summary of the results of the visual observations. The report shall be submitted in accordance with Condition 5.A.4 and shall contain the date of each visible observation, emission point observed, results, and any corrective actions that were taken in the event visible emissions were observed during the reporting period.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c).)

5.C.11 For Emission Points AE-008 and AE-009, the permittee shall submit semiannual reports in accordance with Condition 5.A.4 summarizing the hours of operation of the engine in the calendar year. This report shall also include what hours were for emergency use and what constituted the emergency and what hours were for non-emergency use.

For Emission Point AE-008, this report shall also include all deviations from any emission or operating limitation of Subpart ZZZZ. Such deviations shall include any failure to perform the work practice on the required schedule. In the event a work practice is delayed because the engine is operating during an emergency or if performing the work practice on the required work schedule posed an unacceptable risk under federal, state, or local law, the permittee shall include in the report the reason for the delay.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1). and 40 CFR 63.6640(b), 63.6650(f), and Footnote 1 to Table 2c, Subpart ZZZZ)

5.C.12 For Emission Points AE-001 through AE-007, the permittee shall submit semiannual reports in accordance with Condition 5.A.4 summarizing the hours of operation of the engine in the calendar year. This report shall also include what hours were for emergency use and what constituted the emergency and what hours were for non-emergency use.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 6.3.A(3)(c)(1).)

SECTION 6. ALTERNATIVE OPERATING SCENARIOS

6.1 None permitted.

SECTION 7. TITLE VI REQUIREMENTS

The following are applicable or potentially applicable requirements originating from Title VI of the Clean Air Act – Stratospheric Ozone Protection. The full text of the referenced regulations may be found on-line at **http://www.ecfr.gov/** under Title 40, or DEQ shall provide a copy upon request from the permittee.

7.1 If the permittee produces, transforms, destroys, imports or exports a controlled substance or imports or exports a controlled product, the permittee shall comply with the applicable requirements of 40 CFR Part 82, Subpart A – Production and Consumption Controls.

7.2 If the permittee performs service on a motor vehicle for consideration when this service involves the refrigerant in the motor vehicle air conditioner (MVAC), the permittee shall comply with the applicable requirements of 40 CFR Part 82, Subpart B – Servicing of Motor Vehicle Air Conditioners.

7.3 The permittee shall comply with the applicable requirements of 40 CFR Part 82, Subpart E – The Labeling of Products Using Ozone-Depleting Substances, for the following containers and products:

(a) All containers in which a class I or class II substance is stored or transported;

(b) All products containing a class I substance; and

(c) All products directly manufactured with a process that uses a class I substance, unless otherwise exempted by this subpart or, unless EPA determines for a particular product that there are no substitute products or manufacturing processes for such product that do not rely on the use of a class I substance, that reduce overall risk to human health and the environment, and that are currently or potentially available. If the EPA makes such a determination for a particular product, then the requirements of this subpart are effective for such product no later than January 1, 2015.

7.4 If the permittee performs any of the following activities, the permittee shall comply with the applicable requirements of 40 CFR Part 82, Subpart F – Recycling and Emissions Reduction:

(a) Servicing, maintaining, or repairing appliances;

(b) Disposing of appliances, including small appliances and motor vehicle air conditioners; or

(c) Refrigerant reclaimers, technician certifying programs, appliance owners and operators, manufacturers of appliances, manufacturers of recycling and recovery equipment, approved recycling and recovery equipment testing organizations, as well as persons selling, offering for sale, and/or purchasing class I, class II, or non-exempt substitute refrigerants.

7.5 The permittee shall be allowed to switch from any ozone-depleting substance to any

acceptable alternative that is listed in the Significant New Alternatives Policy (SNAP) program promulgated pursuant to 40 CFR Part 82, Subpart G – Significant New Alternatives Policy Program. The permittee shall also comply with any use conditions for the acceptable alternative substance.

7.6 If the permittee performs any of the following activities, the permittee shall comply with the applicable requirements of 40 CFR Part 82, Subpart H – Halon Emissions Reduction:

(a) Any person testing, servicing, maintaining, repairing, or disposing of equipment that contains halons or using such equipment during technician training;

(b) Any person disposing of halons;

(c) Manufacturers of halon blends; or

(d) Organizations that employ technicians who service halon-containing equipment.

SECTION 8. ACID RAIN REQUIREMENTS

The permittee shall comply with all requirements of the Phase II Acid Rain Permit attached as Appendix C of this permit. All conditions of the Phase II Acid Rain Permit are effective for the dates specified in the Acid Rain Permit; however, these conditions may be revised by the DEQ during the permitted period.

SECTION 9. CROSS STATE AIR POLLUTION RULE REQUIREMENTS

9.1 Description of Cross-State Air Pollution Rule (CSAPR) Monitoring Provisions

The CSAPR subject units and the unit-specific monitoring provisions at this source are identified in the following Table. These units are subject to the requirements for the CSAPR NO_x Ozone Season Group 2 Trading Program.

Unit ID: Emission Points AA-001 and AA-002					
Parameter	Continuous emission monitoring system (CEMS) requirements pursuant to 40 CFR 75, Subpart B (for SO_2 monitoring) and 40 CFR 75, Subpart H (for NO_x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR 75, Appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR 75, Appendix E	Low Mass Emissions (LME) excepted monitoring requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR 75, Subpart E
SO_2	X				
NO_X	X				
Heat Input	X				

Unit ID: Emission Points AA-003, AA-004, AA-005, and AA-006					
Parameter	Continuous emission monitoring system (CEMS) requirements pursuant to 40 CFR 75, Subpart B (for SO_2 monitoring) and 40 CFR 75, Subpart H (for NO_x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR 75, Appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR 75, Appendix E	Low Mass Emissions (LME) excepted monitoring requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR 75, Subpart E
SO_2		X			
NO_X	X				
Heat Input	X				

9.2 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 97.830 through 97.835. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

9.3 The permittee must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at https://www.epa.gov/airmarkets/monitoring-plans-part-75-sources.

9.4 The permittee that wants to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.835. 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/part-75-petition-responses.

9.5 The permittee that wants to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.830 through 97.834 must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.835. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA website at https://www.epa.gov/airmarkets/part-75-petition-responses.

9.6 The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.830 through 97.834, and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

9.7 CSAPR NO_x Ozone Season Group 2 Trading Program Requirements (40 CFR 97.806)

(a) Designated representative requirements - The permittee 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 permittee, 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 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 are in excess of 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 the state (and Indian country within the borders of such state) 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 the state 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 the state (and Indian country within the borders of such state) 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 the state and Indian country within the borders of such state) for such control period exceed the state assurance level.

(ii) The permittee 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 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 the state (and Indian country within the borders of such state) 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 the state (and Indian country within the borders of such state) 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 (and Indian country within the borders of such state) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the permittee fails 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 permittee 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 permittee fails 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 base 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 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 (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) No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Ozone Season Group 2 allowances in accordance with 40 CFR part 97, subpart EEEEE.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR

part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this Title V permit using once permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the permittee 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 permittee 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 permittee 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 permittee, 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.

(h) Effect on units in Indian country. Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regards to any source or unit, in Indian country within the borders of the state.

APPENDIX A

List of Abbreviations Used In this Permit

11 Miss. Admin. Code Pt. 2, Ch. 1.	Air Emission Regulations for the Prevention, Abatement, and Control of Air Contaminants
11 Miss. Admin. Code Pt. 2, Ch. 2.	Permit Regulations for the Construction and/or Operation of Air Emissions Equipment
11 Miss. Admin. Code Pt. 2, Ch. 3.	Regulations for the Prevention of Air Pollution Emergency Episodes
11 Miss. Admin. Code Pt. 2, Ch. 4.	Ambient Air Quality Standards
11 Miss. Admin. Code Pt. 2, Ch. 5.	Regulations for the Prevention of Significant Deterioration of Air Quality
11 Miss. Admin. Code Pt. 2, Ch. 6.	Air Emissions Operating Permit Regulations for the Purposes of Title V of the Federal Clean Air Act
11 Miss. Admin. Code Pt. 2, Ch. 7.	Acid Rain Program Permit Regulations for Purposes of Title IV of the Federal Clean Air Act
BACT	Best Available Control Technology
CEM	Continuous Emission Monitor
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COM	Continuous Opacity Monitor
COMS	Continuous Opacity Monitoring System
DEQ	Mississippi Department of Environmental Quality
EPA	United States Environmental Protection Agency
gr/dscf	Grains Per Dry Standard Cubic Foot
HP	Horsepower
HAP	Hazardous Air Pollutant
lbs/hr	Pounds per Hour
M or K	Thousand
MACT	Maximum Achievable Control Technology
MM	Million
MMBTUH	Million British Thermal Units per Hour
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants, 40 CFR 61 or National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR 63
NMVOC	Non-Methane Volatile Organic Compounds
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards, 40 CFR 60
O&M	Operation and Maintenance
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 μm in diameter
ppm	Parts per Million
PSD	Prevention of Significant Deterioration, 40 CFR 52
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TPY	Tons per Year
TRS	Total Reduced Sulfur
VEE	Visible Emissions Evaluation
VHAP	Volatile Hazardous Air Pollutant
VOC	Volatile Organic Compound

APPENDIX B

List of Regulations Referenced In this Permit

11 Miss. Admin. Code, Part 2, Ch. 1. – Air Emission Regulations for the Prevention, Abatement, and Control of Air Contaminants (Amended November 10, 2016)

11 Miss. Admin. Code, Part 2, Ch. 2. – Permit Regulations for the Construction and/or Operation of Air Emissions Equipment (Amended July 28, 2005)

11 Miss. Admin. Code, Part 2, Ch. 6. – Air Emission Operating Permit Regulations for the Purposes of Title V of the Federal Clean Air Act (Amended June 28, 2012)

40 CFR 82, Protection of Stratospheric Ozone

40 CFR 51, Subpart P, Protection of Visibility

40 CFR 60, Subpart D, Standards of Performance for Fossil Fuel Fired Steam Generators

40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines

40 CFR 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines

40 CFR 63, Subpart ZZZZ, NESHAP for Stationary Reciprocating Internal Combustion Engines

40 CFR 63, Subpart DDDDD, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR 63, Subpart UUUUU, NESHAP for Coal and Oil Fired Electric Utility Steam Generating Units

40 CFR 97, Subpart EEEEE, CSAPR NO_x Ozone Season Group 2 Trading Program

APPENDIX C

Phase II Acid Rain Permit

PHASE II ACID RAIN PERMIT

Issued to: Mississippi Power Company – Plant Victor J. Daniel
Operated by: Mississippi Power Company
ORIS Code: 6073
Effective: *December 31, 2020* to *November 30, 2025*

Summary of Previous Actions:

(1)	Draft permit for public and EPA comment	November 2, 2007
(2)	Permit finalized and issued	January 18, 2008
(3)	Draft TV and Phase II Acid Rain Permits for public and EPA comment	October 12, 2020

Present Action:

(1)	Permit finalized and issued	December 31, 2020

Krystal Rudolph
Signature

December 31, 2020
Date

Krystal Rudolph, P.E.
Chief, Environmental Permits Division
Mississippi Department of Environmental Quality
P.O. Box 2261
Jackson, MS 39225-2261
Telephone (601) 961-5171
Fax (601) 961-5742

PHASE II ACID RAIN PERMIT

Issued to: Mississippi Power Company – Plant Victor J. Daniel
Operated by: Mississippi Power Company
ORIS Code: 6073
Effective: *December 31, 2020* to *November 30, 2025*

ACID RAIN PERMIT CONTENTS:

1) Statement of Basis.

2) SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3) Comments, notes, and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

4) The permit application submitted for this source. The owners and operators of the sources must comply with the standard requirements and special provisions set forth in the application.

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1) STATEMENT OF BASIS:

Statutory and Regulatory Authorities: In accordance with the Mississippi Air and Water Pollution Control Law, specifically Miss. Code Ann. §§ 49-17-1 through 49-17-43, and any subsequent amendments, and Titles IV and V of the Clean Air Act, the Mississippi Department of Environmental Quality issues this permit pursuant to the State of Mississippi Air Emissions Operating Permit Regulations for the Purposes of Title V of the Federal Clean Air Act, 11 Miss. Admin. Code Pt. 2, Ch. 6, and the State of Mississippi Acid Rain Program Permit Regulations for Purposes of Title IV of the Federal Clean Air Act, 11 Miss. Admin. Code Pt. 2, Ch. 7.

2) SO_2 ALLOWANCE ALLOCATIONS AND NO_X REQUIREMENTS FOR EACH AFFECTED UNIT:

		2020	2021	2022	2023	2024
AA-001	**SO_2 allowances, under Table 2 of 40 CFR Part 73.**	9,916*	9,916*	9,916*	9,916*	9,916*
	NO_x limit	Pursuant to 40 CFR 76.11, the Mississippi Department of Environmental Quality approves a NO_x emissions averaging plan for this unit, effective beginning in calendar year 2019. Under the plan, this unit's NO_x emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.45 lbs/MMBtu. In addition, this unit shall have an annual heat input limit of 20,000,000 MMBtu. Under the plan, the actual Btu-weighted annual average NO_x emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_x emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11 (d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit. In accordance with 40 CFR 72.40(b)(1), the averaging plan has been signed and certified by the designated representative and a complete permit application has been submitted for the unit. In addition to the described NO_x compliance plan, 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.				

*The number of allowances allocated to Phase II affected units by U.S. EPA may change in a revision to 40 CFR Part 73, Tables 2, 3, and 4. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

		2020	2021	2022	2023	2024
AA-002	**SO_2 allowances, under Table 2 of 40 CFR Part 73.**	14,303*	14,303*	14,303*	14,303*	14,303*
	NO_x limit	Pursuant to 40 CFR 76.11, the Mississippi Department of Environmental Quality approves a NO_x emissions averaging plan for this unit, effective beginning in calendar year 2019. Under the plan, this unit's NO_x emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.45 lbs/MMBtu. In addition, this unit shall have an annual heat input limit of 15,000,000 MMBtu. Under the plan, the actual Btu-weighted annual average NO_x emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_x emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11 (d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit. In accordance with 40 CFR 72.40(b)(1), the averaging plan has been signed and certified by the designated representative and a complete permit application has been submitted for the unit. In addition to the described NO_x compliance plan, 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.				

*The number of allowances allocated to Phase II affected units by U.S. EPA may change in a revision to 40 CFR Part 73, Tables 2, 3, and 4. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

AA-003A AA-003B AA-004A AA-004B	**SO_2 allowances, under Table 2 of 40 CFR Part 73.**	N/A	N/A	N/A	N/A	N/A
	NO_x limit	N/A				

3) COMMENTS, NOTES AND JUSTIFICATIONS:

Units AA-003A, AA-003B, AA-004A, and AA-004B are natural gas fired combined cycle combustion turbines; therefore, the affected units are not subject to the NO_x requirements outlined in 40 CFR Part 76. Additionally, these are new units that were not listed in 40 CFR 73, Tables 2, 3, or 4, and have not been allocated any SO_2 allowances. For reference, these units are identified as Emission Points AA-003, AA-004, AA-005, and AA-006 in Section 2 of the Title V Operating Permit.

4) PHASE II PERMIT APPLICATION:

The application and NO_x Averaging Plan are attached.

APPENDIX D

Carbon Monoxide Emission Minimization Protocol

Carbon Monoxide
Emissions Minimization Protocol

Mississippi Power Company
Plant Daniel
Unit 1 and Unit 2

Prepared by:

RMB Consulting and Research, Inc.

February 2010

Contents

1.0 Introduction

Mississippi Power Company (MPC) is required to comply with a work practice standard ("best combustion practices") for Unit 1 and Unit 2 at Plant Daniel in lieu of a site-specific carbon monoxide (CO) emissions limitation and continuous CO monitoring. This requirement is based on the Best Available Control Technology (BACT) determination for CO emissions resulting from the recent low NO_x combustion retrofit project. The purpose of this document is to outline the best available combustion practices, including operating and maintenance activities, associated with minimizing CO emissions.

1.1 CO Formation and Control

CO is generated from incomplete combustion of carbon-containing fuels. Reduced combustion temperature, insufficient residence time, and low oxygen levels result in increased formation of CO. These conditions may occur as a result of improper burner operation, burner malfunction, or low excess air levels. Low NOx control technology can contribute to formation of CO, as the staged combustion process reduces the flame temperature and available oxygen in the main combustion zone. While the reduction in available oxygen reduces NO_x formation, it also reduces the conversion of fuel-bound carbon to CO_2, which creates higher levels of partially oxidized carbon (CO). Overfire air is used to reduce CO emissions by introducing additional oxygen downstream of the main combustion zone, which allows the oxidation of additional carbon during the char burnout stage. However, some CO and unburned carbon can still be expected because there is typically insufficient boiler residence time to complete char burnout.

CO formation can be controlled by optimizing combustion efficiency in the boiler, since low CO levels indicate a relatively complete combustion of available carbon in the fuel. However, the ability to reduce CO emissions must be balanced with the need to maintain acceptable NO_x emissions, as the formation of these two pollutants with respect to boiler operating conditions is inversely related. Therefore, best available combustion practices should minimize CO emissions while providing boiler operators with the flexibility to meet NO_x objectives and address operational upsets.

1.2 Document Objectives

This document includes a summary of operating and maintenance procedures designed to optimize and maintain combustion efficiency. The purpose of this document is not to replace or supercede existing operating and maintenance procedures, but rather to highlight certain activities that are essential to optimizing and maintaining boiler performance. Plant staff should continue to follow all relevant manufacturers's recommended procedures for operating and maintaining the unit.

It should be noted that Unit 1 and Unit 2 was recently retrofitted with new low NO_x combustion controls (Foster Wheeler TLN3), including the addition of four new separated over-fired air (SOFA) windboxes and new coal/air nozzle tips and control linkages. These are significant modifications that will require some degree of operating experience in order to fully characterize system operation and the effects on NO_x and CO emissions. Therefore, this

document should be revised, as needed, based on continued operating experience with the new furnace modifications.

2.0 Operating Practices

The following section provides recommended operating practices for minimizing CO emissions during routine boiler operation. Actual boiler operation may vary depending on operational difficulties and NO_x emissions objectives.

2.1 General Recommendations

2.1.1 MPC should follow all manufacturers' recommended operating procedures and those existing procedures established by the plant for startup, shutdown, and malfunction events, to the extent possible.

2.1.2 Initial control settings for the TLN3 NO_x control system were specified following the initial optimization tests on the expected fuel blends to provide optimal NO_x and CO emissions levels. System optimization may be required and new settings determined in the event of a significant change in fuel supply characteristics.

2.1.3 Plant staff should refine operational settings as needed after the initial startup of the TLN3 NO_x system to optimize combustion efficiency and NO_x emissions for various operating conditions. Any significant adjustments to the system should be confirmed with the vendor.

2.1.4 MPC should maintain boiler operating logs while the unit is in operation.

2.1.5 MPC should provide training for boiler operators that includes best practices for optimizing combustion efficiency.

2.2 Recommended Operating Practices

2.2.1 Plant staff should verify that overfire air and windbox tilts/damper positions and control settings are adjusted according to the fuel blend being combusted.

2.2.2 Overfire Air Bias – Overfire air is one of the main factors affecting CO generation. In general, increasing the amount of overfire air (as a percentage of total air) will result in a reduction in NO_x emissions and an increase in CO emissions. CO emissions are also affected by the direction, distribution, and velocity of the overfire air. Operators should adjust the overfire air bias, as needed, to reduce CO and unburned carbon levels.

2.2.3 Air/Fuel Ratio – The overall air/fuel ratio should be maintained as necessary for unit design and fuel conditions.

2.2.4 Pulverizer Operation – Pulverizer coal flows should be balanced within 20% of the design average. Coal and primary air flows to each pulverizer (and

pulverizer exit temperatures) should be consistent with pulverizer operating instructions.

2.2.5 Sootblowing – Sootblowing sequence and individual sootblower steam pressures should be evaluated periodically to ensure adequate furnace cleanliness.

2.2.6 Visual Inspection of Boiler Combustion – An internal, visual inspection of furnace operation should be conducted with the unit online at least once per boiler operator shift. Operators should note fireball location (including flame impingement on boiler walls), flame color/brightness and stability, ash buildup, and waterwall slagging. Furnace operation should be adjusted accordingly if any anomalies are observed.

2.2.7 Coal Fineness – Fuel feed quality and size should be consistent. On a semi-annual basis, an evaluation of pulverizer performance should be conducted by measuring coal fineness, pyrite reject quality and quantity. As a general guideline, at least 75% of the fuel particles should pass through a 200-mesh screen and less than 0.1% should be able to pass through a 50-mesh screen. Pulverizer classifiers should be adjusted or serviced if necessary.

2.2.8 Boiler Operating Parameters – Operating parameters indicative of proper boiler operation (including boiler load, excess air level, air-to-fuel ratio, burner settings, and various stack emissions data including, CO_2, NO_x, O_2, and flue gas flow rate) should be continuously measured. Plant staff should periodically evaluate the operating data to determine any potential problems with the boiler at least once per boiler operator shift.

2.3 Troubleshooting

2.3.1 In event of unusually high carbon loss, the plant may consider (but is not limited to) any or all of the following corrective actions. Care should be taken to maintain NO_x emissions below applicable emissions limits.

- Manually bias closed the SOFA dampers
- Increase secondary air flow
- Balance air flow/O_2 between furnaces
- Verify O_2 trim levels
- Verify that individual auxiliary air and fuel air dampers are open

2.3.2 The following table summarizes the effects of various changes in boiler operation on NO_x and CO emissions.

Boiler Adjustment	NO_x	CO
Increase unit load	▲	=
Increase excess air	▲	▼
Increase pulverizers in service	Depends on elevation	
Increase PA/coal ratio	▲	▼
Increase air upward in windbox	▼	▲
Increase coal bias upward in burner elevation	▲	▲
SOFA tilts aimed upward	▼	▲
Main windbox tilts aimed upward	▲	▲
Increased waterwall slagging	▲	=

3.0 Maintenance Practices

The following section provides recommended maintenance practices for optimizing and maintaining boiler efficiency:

3.0 General Recommendations

3.0.1 MPC should follow all manufacturers' maintenance procedures for those components critical to combustion system at the recommended intervals.

3.0.2 MPC should keep logs of all relevant maintenance activities on those components critical to combustion system.

3.0.3 MPC should perform routine checks and maintenance of critical furnace instrumentation. Precise measurement and control of furnace air and fuel flow rates is essential to optimizing combustion.

3.1 Recommended Maintenance Procedures

3.1.1 Windbox Dampers – All windbox dampers should be periodically cycled during unit outages of sufficient duration through the full operating range to verify operation.

3.1.2 Coal/Air Nozzles – Nozzle tilts should be periodically cycled through the required operating range at least once during an outage of sufficient duration.

3.1.3 Fixed Damper Settings – At least once during an outage of sufficient duration, checks of the TLN3 fixed control damper settings should be conducted to verify they have not been moved since the last system optimization.

3.1.4 Internal Inspection – A thorough internal inspection of the furnace should be conducted during outages of sufficient duration for evidence of tube bridging, waterwall slagging, or flame impingement. Coal/air nozzle tips should be inspected and replaced if excessive corrosion or distortion is noted.

3.1.5 Furnace cleaning – Furnace cleaning schedules should be followed and adjusted, as needed, based on the recent TLN3 modifications.

3.1.6 Air Inleakage – At least once during an outage of sufficient duration, an evaluation of air inleakage should be conducted on the pulverizer, air pre-heater, and the furnace and associated ductwork. Inleakage should be minimized to the extent possible as it can have a significant effect on unit heat rate.

APPENDIX E

Custom Fuel Monitoring Plan

Custom Fuel Sampling and Analysis Plan
For Mississippi Power Company's Plant Daniel Units 3a, 3b, 4a and 4b

Introduction

Mississippi Power Company's Plant Daniel, located in Escatawpa, MS, includes four combine cycle units (Units 3a, 3b, 4a and 4b). All units are identical and consist of a General Electric Frame 7FA natural gas-fired combustion turbine that exhausts into a heat recovery boiler. Each heat recovery boiler is equipped with a natural gas-fired supplementary duct burner. The flue gases from each of the four heat recovery boilers exhaust to atmosphere via four independent stacks.

Each combustion turbine is directly coupled to an electrical generator with a nominal rating of 170 MWe each. In addition, the steam generated in each pair of heat recovery boilers (3a and 3b are a pair and 4a and 4b are a pair) is used to drive a steam turbine that is coupled with a 190 MWe rated electrical generator.

For NO_X control, each turbine uses "dry low NO_X" technology and each heat recovery boiler is equipped with a selective catalytic reduction (SCR) catalyst bed. At full load, each unit is permitted to emit 0.013 lb./mmBtu of NO_X or approximately 3.5ppm @ 15% O_2.

Applicable Regulations

Units 3a, 3b, 4a and 4b are subject to the Federal New Source Performance Standards at 40 CFR Part 60, Subpart GG and Subpart Db and, as such, must comply with the applicable emission limits and monitoring requirements of these Subparts. The units are also subject to the requirements of the Continuous Emissions Monitoring provisions of the Acid Rain Program contained in 40 CFR Part 75. Since each unit is equipped with SCR and only emits approximately 3.5 ppm NO_X, both units meet the NO_X emission limitations of Subpart GG and Db by a wide margin (approximately an order of magnitude). In addition, as required by 40 CFR Part 75, each unit is equipped with a continuous emissions monitor for the measurement of NO_X and CO_2 so that NO_X emissions can be reported in lb./10^6 Btu. Measurements of SO_2 emissions and heat input are done under the provisions of 40 CFR Part 75, Appendix D. In general, when natural gas is the fuel, Appendix D allows the use of measured fuel flow, gross calorific value and a conservative default SO_2 emissions factor to determine the unit heat input and SO_2 emissions. Appendix D of 40 CFR Part 75[1] contains a number of criteria related to gaseous fuel sulfur content, sampling procedures and analysis procedures. The custom fuel plan contained herein conforms to the requirements of 40 CFR Part 75.

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[1] 40 CFR Part 75 was revised very recently (Fed Reg 28563, May 26, 1999) and many of the gaseous fuel criteria were extensively modified.

Subpart GG

40 CFR Part 60, Subpart GG is an older regulation, having been promulgated almost 10 years ago. The NO_X control technology on modern gas turbines and the almost exclusive use of natural gas and No. 2 GT fuel oil have essentially made the regulation obsolete. At the time Subpart GG was promulgated, NO_X emissions from gas turbines were controlled by steam or water injection into the combustion zone. Typical emissions were 75-150 ppm NO_X. Modern gas turbines that burn natural gas do not typically use water or steam injection but use variations of "lean burn" technology for NO_X control. Emissions from these units range from 9 to 25 ppm NO_X when burning gaseous fuels. Consequently, the monitoring and reporting sections of Subpart GG have been made superfluous, especially in light of the 40 CFR Part 75 monitoring and reporting requirements.

Subpart GG has several monitoring provisions in §60.334. They are:

1. §60.334(a) - If water or steam injection is used, a fuel and water/steam flow measurement must be installed to monitor and record the fuel consumption and ratio of water to fuel being fired in the turbine.

2. §60.334(b) - To monitor sulfur and nitrogen content of the fuel being fired in the turbine. Fuel sampling and analysis frequency is specified as when the bulk storage tank is filled, or in the case where there is no storage tank, daily. This section of the regulation also provides for the owner/operator of the gas turbine facility to develop custom schedules for determining the fuel sulfur and nitrogen content of the fuel, "..... based on the design and operation of the affected facility and the characteristics of the fuel supply."

Obviously, the requirements in §60.334(a) are moot with respect to Daniel Units 3a, 3b, 4a, and 4b because none of the units use water or steam injection for NO_X control. In addition, the intent of §60.334(a) is to insure that the owner operates the NO_X control equipment such that there is a reasonable assurance of continued NO_X compliance. This intent is clearly satisfied by the use of continuous emissions monitors on Units 3a, 3b, 4a, and 4b.

On the surface, the language in §60.334(b) appears to require daily fuel sampling and analysis, even for natural gas. The requirement seems to be nonsensical because natural gas does not contain any fuel-bound nitrogen and simply cannot contain enough sulfur to cause the SO_2 emission limits of Subpart GG (0.8 weight percent fuel sulfur content) to be violated. A review of the Environmental Protection Agency's Standards Support document for Subpart GG[2] clearly shows that these requirements were only intended to apply to oil; perhaps only non-premium oil (i.e., crude and residual oil).

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[2] US Environmental Protection Agency, Office of Air Quality Planning and Standards, Standards Support and Environmental Impact Statement Volume 1: Proposed Standards of Performance for Stationary Gas Turbines, EPA-450/2-77-017a, September 1977.

It should be recalled that there was an unstable world-wide situation with respect to gas and oil supply when the Subpart GG regulation was being developed and the agency was very sensitive about restricting the fuels available to gas turbines. To allow for the combustion of some portion of the available heavy oil supply, the agency decided to allow a fuel bound nitrogen allowance and a fairly high fuel sulfur content. We quote from the support document. "As also discussed earlier, nearly all stationary gas turbines are currently firing natural gas or premium distillate fuel oil; although over the next five to ten years, some new gas turbines may fire heavy or residual fuel oil for either economic reasons or if a shortage in supply of premium fuel oils should develop. A fuel-bound nitrogen allowance to permit increased NO_X emissions has been selected to allow turbines to burn approximately 50 percent of currently available heavy fuels. To be consistent with the objective of the fuel-bound nitrogen allowance, the SO_2 emission limit is selected as 150 ppm referenced to 15 percent O_2. This corresponds to a fuel sulfur content of approximately 0.8 percent by weight and would allow about 50 percent availability of heavy fuel oils."[3]

"Consequently, any owner or operator that uses the fuel-bound nitrogen allowance to comply with the NO_X emission limit will be required by the standard to monitor the nitrogen of the fuel."[4]

All of this evidence points to a very reasonable regulatory approach by the Agency and we cannot imagine that the intent was to require daily fuel sampling and analysis for sulfur and fuel bound nitrogen when premium gaseous fuels are being fired.

Custom Fuel Plan for Plant Daniel Units 3a, 3b, 4a and 4b

It is suggested that a custom fuel sampling and analysis plan be used that mirrors the requirements of Appendix D to 40 CFR Part 75. The recent revisions to Appendix D require a confirmation of gas quality with respect to sulfur content, use of conservative default values for SO_2 emissions and monthly sampling and analysis for heat content. Results are reported to EPA every quarter on an hourly basis in the Part 75 electronic data report.

In the case of the Daniel Units, the gas burned conforms to the regulatory requirements for natural gas (a maximum H_2S content of 1.0 gr./100 cf.). This has been confirmed by the gas pipeline tariffs as specified in 40 CFR Part 75. The sulfur content will still be approximately 150 times less than that allowed by 40 CFR Part 60, Subpart GG. Subpart GG allows for a fuel sulfur content of 0.8% by weight and this is equivalent to an H_2S content of approximately 300 gr/100 scf. It is suggested that this huge sulfur content compliance margin eliminates the need for sulfur content sampling and analysis based on the characteristics of the fuel. SO_2 emissions will be reported based on the 40 CFR Part 75, Appendix D default factor of 0.0026 lb. $SO_2/10^6$ Btu.

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[3] IBID, pages 8-34, 8-35
[4] IBID, page 8-36

Therefore, a relatively simple custom fuel plan for Plant Daniel Units 3a, 3b, 4a and 4b is proposed as follows:

- **The applicability of the Natural Gas specification will be demonstrated as required by 40 CFR Part 75, Appendix D.**
- **No periodic sampling for fuel sulfur will be required because of the significant sulfur content compliance margin.**
- **No periodic sampling of fuel bound nitrogen will be required because natural gas contains no fuel bound nitrogen**
- **Monthly sampling will be conducted for gross calorific value (GCV) as required by 40 CFR Part 75, Appendix D.**
- **SO_2 and NO_X emissions will be reported as required by 40 CFR Part 75, Appendix D in the electronic format specified by the regulation.**

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

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

This submission is: ☐ **new** ☐ **revised** ☐ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Daniel Electric Generating Plant	MS	006073

STEP 2

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

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
AA-003A	Yes
AA-003B	Yes
AA-004A	Yes
AA-004B	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Daniel Electric Generating Plant
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.

Daniel Electric Generating Plant
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.

Daniel Electric Generating Plant
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,

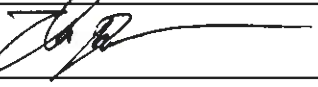
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

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 Mark P. Loughman, Director - Environmental Affairs	
Signature 	Date 3/10/20