Pre-Construction Review

and

Final Determination

of Approval for

Entergy Mississippi LLC, Delta Blues Advanced Power Station

Facility No. 2800-00142

Technical Review
by
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Air Quality Analysis
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SECTION 1

FINAL DETERMINATION

Both VOCs and PM emissions are expected to be emitted from the combustion turbine lube oil vent and the steam turbine lube oil vent. The lube oil vent will be permitted to operate continuously (8,760 hr/yr).

Natural Gas System and Dewpoint Heater Operations

Pipeline quality natural gas will be delivered to the site via pipeline where it is metered and piped to the natural gas-fired units. To prevent liquid droplets from entering the GT, the natural gas fuel to the GT will be indirectly heated in a small natural gas fired dewpoint heater). The dewpoint heater will be permitted to operate continuously (8,760 hr/yr).

Combined Cycle Unit Startup/Shutdown Operations

Startup/Shutdown ("SUSD") of the proposed combined cycle unit will occur infrequently as DBAPS will be a base load power plant. Startup is defined as the period beginning when the gas turbine receives a "turbine start" signal and an initial flame detection signal is recorded in the plant's control system and ending when the combustion turbine output reaches minimum sustainable load (50% load), which is typically the point at which the unit reaches the lean pre-mix operating mode. The shutdown period is defined as the period beginning when the gas turbine receives a "turbine stop" command and the generator output drops below the minimum stable load (50% load) and ending when a flame detection signal is no longer recorded in the plant's control system. SUSD emissions from the combined cycle unit are emitted from the main stack (DBAPS-1A) and are accounted for in the annual emission limits for this point source. The SCR and catalytic oxidation units will be coming up to temperature and not fully operational during SUSD; therefore, SUSD are not controlled.

Higher-than-normal emissions from the main stack may occur during gas turbine tuning and optimization maintenance activities. In addition to gas turbine optimization during the commissioning period, the gas turbine's fuel system requires periodic tuning, including after major overhauls, to maintain compliance with manufacturer's specifications for emissions and combustion dynamics. The turbine tuning is conducted across the combustor's load range and according to manufacturer recommendations to minimize NOx and CO production while ensuring combustor stability. During these gas turbines tuning and optimization activities, the gas turbine CO and NOx emissions will be limited to the same levels as SUSD.

Diesel-fired Emergency Internal Combustion Engines

The DBAPS will have two emergency diesel-fired IC engines. The engines will be limited to 100 hr/yr of operation or less in non-emergency operating modes due to the engines' emergency classification status. The engines will not be constrained by an operating limit for legitimate emergency operating modes.

One emergency diesel-fired IC engine is a 2,180-kilowatt (kW) emergency standby generator. The proposed engine is a Mitsubishi Model S16R-Y2PTAW2-1 with a 2,932 BHP rating. The engine will only fire Ultra Low Sulfur Diesel (ULSD) with a maximum sulfur content of 15 parts per million weight (ppmw). The engine will be a USEPA-certified Tier 2 engine.

40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU). Emission Point AA-001 meets the definition of a new, stationary combustion turbine under this subpart and as such, is subject to this subpart.

40 CFR 63, Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

This subpart establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations. Emission Points AA-002 and AA-003 meet the definition of new, stationary RICE located at an area source of HAP in which construction was commenced after June 12, 2006. As such, these emission points are subject to this subpart. However, compliance with 40 CFR 63, Subpart ZZZZ will be achieved by complying with all applicable requirements under 40 CFR 60, Subpart IIII since these engines are considered "new or reconstructed RICE located at an area source". As such, no further requirements apply for such engines under 40 CFR 63, Subpart ZZZZ.

IV. Best Available Control Technology (BACT) Analysis

Table 1. PSD Applicability

Pollutant	Project-Related Increases (TPY)	Significant Emission Rate (TPY)	Netting Analysis Required? (Yes/No)	Contemporaneous Emissions (TPY)	Total Net Emissions (TPY)	PSD Review Required? (Yes/No)
PM	103.86	25	No	0.00	103.86	Yes
PM_{10}	166.54	15[1]	No	0.00	166.54	Yes
$PM_{2.5}$	166.54	10	No	0.00	166.54	Yes
NO_X[1,2]	230.35	40	No	0.00	230.35	Yes
SO_2[1]	30.37	40	No	0.00	30.37	No
VOC[2]	405.96	40	No	0.00	405.96	Yes

The first step in the "top down" approach is to determine, for the emissions unit and the PSD pollutant in question, the most stringent demonstrated control technology available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for this project, the next most stringent level of control is then determined and similarly evaluated. This process continues until a control technology and associated emission level is determined that cannot be eliminated by any technical or economic infeasibility. The "top-down" approach has been employed in this analysis to evaluate available pollution controls for the proposed DBAPS. The following sections describe the pollutant-by-pollutant BACT for all emissions units at the proposed Delta Blues facility.

A. Gas Turbine/Duct Burner Combustion Main Stack

The power generation equipment proposed for Sawgrass includes a Mitsubishi Model M501JAC GT equipped with supplementary-fired duct burners and a HRSG. The BACT demonstration for the GT/duct burner main stack is presented as follows for each NSR regulated pollutant emitted from SPS-1A.

(1) Nitrogen Oxides (NOx) BACT Analysis

NOx is generally formed during combustion by thermal oxidation of nitrogen in the combustion air (thermal NOx) and the oxidation of nitrogen in the fuel (fuel-bound NOx). Natural gas contains relatively small amounts of fuel-bound nitrogen and NOx formation through the fuel NOx mechanism is expected to be insignificant. The main variables affecting NOx generation in the gas turbine/duct burner installations are temperature, the availability of nitrogen, the availability of oxygen, and the extent of contact between nitrogen and oxygen during the combustion process. NOx formation is maximized in zones of high combustion temperatures.

Step 1: Identify Available Control Technologies

Available NOx control technologies for gas turbine/duct burner installations include:

- **Wet Injection**: The injection of water directly into the combustion chamber lowers the flame temperature by absorbing heat necessary to vaporize the water and raise the temperature of the steam to that of the combustion temperature. Steam injections utilize the same principle, although heat can only be absorbed by the steam in raising the steam's temperature to that of combustion. Injection of either water or steam results in lower "thermal NOx" formation. This technology can achieve a flue gas NOx concentration of 42 ppmvd @ 15% O2.

- **Dry Low-NOx Combustor/Burner Design**: One method of reducing "thermal NOx" formation is by utilizing a dry low-NOx (DLN) combustor that premixes the air and fuel prior to entering the primary combustion chamber. This allows for a lower flame temperature due to the homogeneity of the air/fuel mix, and the lack of a flame front.

Entergy proposes to accept the top control technology in Table 7.1. The GT/duct burner system will utilize dry low-NOx combustors and an ammonia-based SCR control system which will yield a vendor-guaranteed flue gas NOx concentration of 2.0 ppmvd NOx @ 15% O2 (24-hr-average basis). A review of RBLC confirms this control system represents the top available and technically feasible NOx control technology for GT/duct burner systems. Of the 58 RBLC entries with a PSD BACT limit of 2.0 ppmvd @ 15% O2, 22 of those entries had a primary limit averaging period 24-hr which was the most common averaging period.

Table 7.1: GT/DB NO_X Technically Feasible Control Options		
Ranking	**GT/DB NO_X Control Technology**	**NO_X Concentration (PPMVD @ 15% O_2)**
1	SCR + Dry Low NO_X Combustors/Burners	2.0
2	SCR	2 – 3
3	Dry Low NO_X Combustors/Burners	9 – 25
4	Water/Steam Injection	42

(2) <u>Carbon Monoxide (CO) BACT Analysis</u>

Carbon monoxide forms in combustion devices as a product of incomplete combustion. Production of CO results when there is a lack of oxygen and insufficient residence time at high enough temperatures to complete the final step in oxidation. Controlling these factors to decrease CO, however, also tends to result in increased emissions of NOx. Conversely, a lower NOx emission rate achieved through flame temperature control may result in higher levels of CO emissions. Thus, a balance must be established, whereby the flame temperature, residence time and excess oxygen are set to achieve the lowest NOx emission rate possible to comply with BACT while keeping CO emissions to an acceptable level.

Step 1: Identify Available Control Technologies

The two available CO control options for gas turbine/duct burner installations include:

• Combustion Controls/Good Combustion Techniques, and

• Catalytic Oxidation Add-on Control Device

CO combustion control performance (good combustion techniques) is a function of available oxygen, combustion temperature, turbulence, and residence time. Formation of CO is a result of incomplete combustion of the fuel. Adequate fuel residence time and high temperature in the combustion zone can ensure minimal CO formation. A properly designed combustion system is

Step 1: Identify Available Control Technologies

Similar to CO, there are two available VOC control options for gas turbine/duct burner installations:

- Combustion Controls/Good Combustion Techniques, and
- Catalytic Oxidation Add-on Control Device.

Step 2: Eliminate Technically Infeasible Options

The two available VOC control technologies for gas turbine/duct burner installations identified above are both technically feasible. Entergy is proposing to employ both of these VOC control technologies for this gas turbine/duct burner system.

Step 3: Rank Remaining Options by Control Effectiveness

The top VOC control technology is identified as good combustion techniques along with an add-on catalytic oxidation. In conjunction, these two technologies will result in a flue gas VOC concentration of 1.5 ppmvd @ 15% O2 (annual-average basis).

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because Entergy is proposing to accept the top VOC control technology.

Step 5: Select BACT

The GT/duct burner system will utilize good combustion techniques and a catalytic control system which will yield a vendor-guaranteed flue gas VOC concentration of 1.5 ppmvd VOC @ 15% O2 (annual-average basis). Based on a review of RBLC, this control system represents the "top" available and feasible VOC control technology for GT/duct burner systems. As a result, catalytic oxidation with a VOC performance level of 1.5 ppmvd VOC @ 15% O2 (annual-average basis) is selected as BACT for VOC. Because the "top" control technology is selected, no further VOC BACT analysis is required.

(4) Particulate Matter (PM_{10} and $PM_{2.5}$) BACT Analysis

Particulate matter (PM) emissions, which include both PM10 and PM2.5 emissions, from combined cycle turbine/duct burner installations are the result of unburned trace constituents in the fuel, unburned hydrocarbons, and the inlet air supply that may contain dust particles. PM emissions can also result from the formation of sulfates and nitrates, which are formed when certain sulfur- and nitrogen-oxide compounds react with ammonia. The following section describes control technologies that can be applied to reduce PM emissions from this gas turbine/duct burner installation.

Step 1: Identify Available Control Technologies

Step 1: Identify Available Control Technologies

The two available control technologies to control SAM emissions include:

• Wet scrubbing of SAM, and

• Use of clean burning, low sulfur natural gas fuel.

Step 2: Eliminate Technically Infeasible Options

Because the sulfur content in pipeline natural gas is extremely low, the SAM concentration in the flue gas will be very dilute. For this reason, wet scrubbing of SAM emissions is technically infeasible and is eliminated from BACT consideration. Additionally, wet scrubbing would have the negative impact of generating an additional wastewater stream.

Step 3: Rank Remaining Options by Control Effectiveness

The only available and technically feasible SAM control technology is the use of clean-burning, low sulfur natural gas fuel.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because Entergy is proposing to accept the top control technology.

Step 5: Select BACT

The proposed BACT for SAM emissions includes minimizing the formation of SO2 and H2SO4 by using pipeline-quality natural gas with sulfur content not exceeding 1.0 grains S/100 scf on a short-term basis, and not exceeding 0.5 grains S/100 scf on an annual-average basis. Additionally, by employing a highly efficient combined cycle power generation system, the quantity of natural gas fuel required per unit of power output is minimized to the extent reasonably possible.

(6) ***Greenhouse gas (GHG) BACT Analysis***

For the GT/duct burner system, GHG emissions will be released from the main stack in the form of CO2, methane (CH4) and nitrous oxide (N2O). The primary GHG is CO2, and the combined GHGs are expressed as CO2 equivalents (CO2e) using the procedure in the federal GHG reporting rule found at 40 CFR 98.

Important Note: Since this GT/duct burner GHG BACT demonstration was originally submitted to MDEQ on April 9, 2024, EPA promulgated a new NSPS GHG regulation which impacts this installation. In the May 9, 2024, Federal Register, EPA published 40 CFR 60 Subpart TTTTa (NSPS TTTTa), which establishes GHG standards for Stationary Combustion Turbine Electric Generating Units built after May 23, 2023. NSPS TTTTa implements a phased-in GHG control approach. The new regulation focuses only on CO2 emissions and not any other GHG constituents. EPA's reason for phasing in GHG limits for this source category was that some of commences operation, the infrastructure to even partially fire hydrogen fuel is not readily available (e.g., there is no hydrogen pipeline near the site to obtain hydrogen fuel). For this reason, hydrogen combustion is rejected as GHG BACT for this installation. However, Entergy will consider hydrogen combustion when planning for operation of the facility to meet the NSPS TTTTa CO2 emission limit that becomes effective on January 1, 2032.

Step 2: Eliminate Technically Infeasible Options

All of the control options identified in Step 1 are technically feasible. As described above, at the time of the application and hydrogen combustion is not currently available as a GHG control options because of infrastructure limitations (see Step 1). However, these options may be available by the 2032 timeframe. The only remaining GHG control options are CCS and building and operating a system that has a high thermal efficiency while burning a relatively low-carbon natural gas fuel.

Step 3: Rank Remaining Options by Control Effectiveness

CCS is the top technically feasible control technology. The remaining option is building and operating a system that has a high thermal efficiency while firing a relatively low-carbon natural gas fuel.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

Currently, the initial costs of installing a CCS system are estimated at nearly $1.3 billion. For this reason, CCS is considered economically infeasible.

Step 5: Select BACT

The remaining option for GHG BACT is to employ a GT/duct burner combined cycle system with a high thermal efficiency that is fired by relatively low-carbon natural gas fuel. This is consistent with recent BACT determinations for combined cycle systems presented in USEPA's RBLC database as shown in Appendix C. The minimum acceptable GHG BACT limit of 800 lb CO2/MWh gross power output is established by 40 CFR 60 Subpart TTTTa. This NSPS TTTTa CO2 limit will represent GHG BACT for this installation. This selection will place Sawgrass in the group of the top performing combined cycle units identified in USEPA's RBLC database presented in Appendix C. Based on this, the proposed GHG BACT for the GT/duct burner system is use of natural gas fuel with efficient power generation system with a GHG performance level of 800 lb CO2e/MWh of gross power output.

The proposed NOx BACT for the emergency engines is a Tier 2 or Tier 3 engine NOx performance level specified in NSPS IIII. This corresponds to the NOx limit for emergency service engines in 40 CFR 60 Subpart IIII, the NSPS for Compression Ignition Internal Combustion Engines. Both engines will be subject to and will comply with all applicable NSPS Subpart IIII NOx requirements for engines that maintain an emergency classification. For the diesel-fired Emergency Standby Generator, NOx BACT is proposed as the Tier 2 NOx performance level of 5.36 g NOx/kWh for engines of this power rating. For the diesel-fired Emergency Fire Water Pump (DBAPS-FWP) NOx BACT is proposed as the Tier 3 NOx performance level of 3.31 g NOx/kWh for engines of this power rating.

(2) *__Carbon Monoxide (CO) BACT Analysis__*

Step 1: Identify Available Control Technologies

The CO control technologies that are available include:

• Catalytic oxidation of CO and

• Good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII CO emission limits.

Step 2: Eliminate Technically Infeasible Options

Both options identified above are technically feasible.

Step 3: Rank Remaining Options by Control Effectiveness

Catalytic oxidation provides the best control effectiveness, followed by use of an engine certified to meet applicable NSPS IIII CO emission limits.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

Although an add-on catalytic control system is technically feasible for the two subject emergency engines, the cost of controlling CO for this application is economically prohibitive. Total annual CO emissions from the two engines combined are very small and can be found in Tables A-8 and A-9 in Appendix A of the PSD application. This is due to engine operations being limited to 100 hr/yr/engine. For both engines, as shown in the control equipment cost calculations presented in Appendix D of the PSD application, the annualized cost for controlling CO emissions using a catalytic oxidizer exceeds $100,000 per ton of CO controlled. For this reason, catalytic oxidation is rejected as BACT for CO.

Step 5: Select BACT

The proposed CO BACT for the emergency engines is a manufacturer performance guarantee CO performance level using engines certified to meet NSPS IIII CO emission limits. Both engines will be subject to and will comply with all applicable NSPS Subpart IIII CO requirements for engines

Water Pump VOC BACT is proposed as the manufacturer's VOC performance level of 0.11 g VOC/kWh.

(4) ***Particulate Matter (PM_{10} and $PM_{2.5}$) BACT Analysis***

Step 1: Identify Available Control Technologies

The control technologies that can potentially be used to control PM emissions include:

• Fabric Filter (Baghouse);

• Electrostatic Precipitator (ESP); and

• Good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII PM emission limits.

Step 2: Eliminate Technically Infeasible Options

Because operation of the two engines are so infrequent (< 100 hr/yr) and the PM concentration in the engine flue gas is so dilute, it is technically infeasible to use PM add-on control equipment such as a fabric filter or ESP.

Step 3: Rank Remaining Options by Control Effectiveness

The only remaining option is employing good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII PM emission limits. This becomes the top technology.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because Entergy is proposing to accept the top technically feasible control technology.

Step 5: Select BACT

The proposed PM BACT for the emergency engines is a Tier 2 or Tier 3 engine PM performance level using engines certified to meet NSPS IIII. This corresponds to the PM limit for emergency engines in 40 CFR 60 Subpart IIII, the NSPS for Compression Ignition Internal Combustion Engines. Both engines will be subject to and will comply with all applicable NSPS Subpart IIII PM requirements for engines that maintain an emergency classification. For the diesel-fired Emergency Standby Generator PM BACT is proposed as the Tier 2 PM performance level of 0.173 g PM/kWh for engines of this power rating. For the diesel-fired Emergency Fire Water Pump PM BACT is proposed as the Tier 3 PM performance level of 0.10 g PM/kWh for engines of this power rating.

(5) ***Greenhouse Gas (GHG) BACT Analysis***

Step 1: Identify Available Control Technologies

• Selective Catalytic Reduction (SCR);

• Selective Non-Catalytic Reduction (SNCR); and

• Use of Ultra-Low NOx Burners

Step 2: Eliminate Technically Infeasible Options

The use of add-on NOx controls such as SCR or SNCR is not technically feasible for this small heater. SCR and SNCR are control technology typically used on heaters with ratings greater than 100 MWh with this heater having a rating of 1.06 MWh. The use of add-on NOx controls for this application is therefore rejected as BACT.

Step 3: Rank Remaining Options by Control Effectiveness

The only available and technically feasible NOx control technology for this heater is the use of ULNBs with a manufacturer's guaranteed NOx performance level of 0.011 lb NOx/MMBtu. This becomes the top technology.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because Entergy is proposing to accept the technically feasible top control technology.

Step 5: Select BACT

NOx emissions from this small heater can be found in Table A-10 of Appendix A of the PSD application. NOx BACT for this heater is proposed to be the use of ultra-low NOx burner technology with a manufacturer's guaranteed NOx performance level of 0.011 lb NOx/MMBtu.

(2) *Carbon Monoxide (CO) BACT Analysis*

Step 1: Identify Available Control Technologies

The CO control technologies that are available for this small gas-fired heater include:

• Oxidation catalysts and

• Employing good combustion techniques with a manufacturer's guaranteed CO performance level.

Step 2: Eliminate Technically Infeasible Options

The use of add-on CO controls such as an Oxidation Catalyst Unit is not technically feasible for this small heater. Oxidation catalysts are usually used on heaters with a rating greater than 100 MWh with this heater having a rating of 1.06 MWh. The use of add-on CO controls for this application is therefore rejected as BACT.

Step 3: Rank Remaining Options by Control Effectiveness

good combustion practices to achieve a manufacturer's guaranteed VOC performance level of 0.008 lb VOC/MMBtu.

(4) ***Particulate Matter (PM_{10} and $PM_{2.5}$) BACT Analysis***

Step 1: Identify Available Control Technologies

The control technologies that can potentially be used to control PM10/PM2.5 (PM) emissions from this very small heater include:

• Fabric Filter (Baghouse);

• Electrostatic Precipitator (ESP); and

• Good combustion practices using clean low-sulfur pipeline natural gas as a fuel with a burner manufacturer's guarantee to have low PM emissions.

Step 2: Eliminate Technically Infeasible Options

Because the heater is very small and the PM concentration in the heater flue gas is so dilute, it is technically infeasible to use PM add-on control equipment such as a fabric filter or ESP. Further, there are no known commercial applications of add-on PM controls for natural gas fired heaters, so this control option is also not "available".

Step 3: Rank Remaining Options by Control Effectiveness

The only remaining option is employing good combustion practices and by using clean natural gas as a fuel and with a burner manufacturer's guarantee to have low PM emissions. This becomes the top technology.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because Entergy is proposing to accept the technically feasible top control technology.

Step 5: Select BACT

PM10/PM2.5 emissions from this small natural gas-fired heater can be found in Table A-10 of Appendix A of the PSD application. PM10/PM2.5 BACT for this heater is proposed to be the use of low sulfur pipeline natural gas and good combustion practices to achieve a manufacturer's guaranteed PM performance level of 0.0048 lb PM/MMBtu.

(5) ***Greenhouse Gas (GHG) BACT Analysis***

Step 1: Identify Available Control Technologies

The GHG control technologies that are considered in this case include:

• Carbon Capture and Sequestration (CCS) and

- Use of an external floating roof tank;
- Use of a fixed roof tank with the tank vent routed to and add-on VOC control device; and
- Use of a fixed roof tank with a submerged fill pipe and an atmospheric vent.

ULSD has a very low vapor pressure of 0.014 psia at storage conditions. As a result, the combined annual VOC emission from these two tanks will be very small. Due to the size of the proposed fixed roof tanks, the fixed roof will control fugitive emissions at a similar rate to the other tanks listed above, while being much more mechanically simple. As such, fixed roof tanks with a submerged fill pipe and an atmospheric vent are the industry standard for tanks of this size storing liquids with very low vapor pressures. The proposed BACT for these two tanks is the use of white horizontal fixed-roof storage vessels with a submerged fill pipe and an atmospheric vent.

Step 2: Eliminate Technically Infeasible Options

The best available control technology for ULSD storage is use of a fixed roof tank with a submerged fill pipe and an atmospheric vent.

Step 3: Rank Remaining Options by Control Effectiveness

The best available control technology for ULSD storage is use of a fixed roof tank with a submerged fill pipe and an atmospheric vent.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because Entergy is proposing to accept the top control technology.

Step 5: Select BACT

Because ULSD has a very low vapor pressure of 0.014 psia at storage conditions, the combined annual VOC emission from these two small tanks combined will be very low. Therefore, the proposed BACT for these two tanks is the use of white horizontal fixed-roof storage vessels with a submerged fill pipe and an atmospheric vent.

E. Lube Oil System Vents

The new combustion turbine and new steam turbine will each be equipped with a dedicated lubrication system. Lubrication oil will be circulated through each turbine's machinery from the systems' oil sumps. The oil sumps will be equipped with a vent that will be controlled by an oil mist eliminator. Emissions from the oil mist eliminators are based on lube oil replacement rates for similar units equipped with mist eliminators. Both VOCs and PM are expected to be emitted from for the combustion turbine lube oil vent and the steam turbine lube oil vent. The lube oil vent will be permitted to operate continuously (8,760 hr/yr).

No evaluations of cost or other impacts are required because Entergy is proposing to accept the top control technology.

Step 5: Select BACT

The combined PM emissions from both lube oil vents can be found in Table A-15 in Appendix A. Use of a mist eliminator is the only feasible PM control technology for these small PM sources. Therefore, use of a mist eliminator is proposed as PM10/PM2.5 BACT for the two lube oil vents.

F. Fugitive Emissions

The proposed equipment at SPS has the potential to leak VOC and GHG from equipment components. These components include valves, flanges and connectors, pumps, etc. For the natural gas fugitives (Emission Point AA-005), the VOC composition of the natural gas is only 1.58 wt%. The total annual fugitive VOC emissions from this source can be found in Table A-12 in Appendix A of the PSD application. Methane in natural gas is a GHG. Fugitive GHG emissions for AA-005 represents 0.01% of the facility-wide GHG annual emission rate. The GHG emissions for AA-005 can be found in Table A-24 of Appendix A of the PSD application and the facility-wide GHG annual emission rate can be found in Table A-21 of Appendix A of the PSD application. For the diesel fugitives (Emission Point AA-007), annual fugitive VOC emissions is low due to the limited number of components in diesel service and that diesel is a low-emitting heavy liquid. The emissions from this source can be found in Table A-14 in Appendix A of the PSD application. There currently are no NSPS or NESHAP regulations which require a Leak Detection and Repair (LDAR) program for the fugitive sources (Emission Points AA-005and AA-007). If an LDAR program were implemented at Sawgrass, it would monitor both VOC and GHG (methane) emissions.

(1) <u>Volatile Organic Compounds (VOC) BACT Analysis</u>

Step 1: Identify Available Control Technologies

The available VOC control technologies for fugitive VOC emissions include:

• Implementing a traditional Leak Detection and Repair (LDAR) program using a portable hydrocarbon monitor and

• Implementing an Audio-Visual-Olfactory (AVO) LDAR program.

Step 2: Eliminate Technically Infeasible Options

Both LDAR program options identified above are technically feasible.

Step 3: Rank Remaining Options by Control Effectiveness

An LDAR program using a portable hydrocarbon detector is expected to have better control than an AVO LDAR program.

Step 5: Select BACT

Most fugitive methane is emitted from natural gas components (DBAPS-NGFUG). Because pipeline natural gas is odorized with a small quantity of mercaptan, an Audio-Visual-Olfactory (AVO) program to detect and repair leaks is technically feasible, highly effective and is the top remaining control option. For this reason, an AVO program is proposed for GHG BACT for Emission Points AA-005 and AA-007.

V. Source Impact Analysis

The owner or operator of a proposed source or modification is required to demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), will not cause or contribute to air pollution in violation of: 1) any national ambient air quality standard in any air quality control region; or 2) any applicable maximum allowable increase over the baseline concentration in any area.

The modeled concentrations used to determine compliance with any NAAQS and PSD increment depend on 1) the type of standard, i.e., deterministic or statistical, 2) the available length of record of meteorological data, and 3) the averaging time of the standard being analyzed. When the analysis is based on 5 years of National Weather Service meteorological data, the following estimates are used:

- For deterministically based standards (e.g., SO_2), the highest, second-highest short term estimate and the highest annual estimate; and
- For statistically based standards (e.g., PM_{10}), the highest, sixth-highest estimate and highest 5-year average estimate.

The owner or operator of a proposed source or modification is required to demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), will not cause or contribute to air pollution in violation of: 1) any national ambient air quality standard in any air quality control region; or 2) any applicable maximum allowable increase over the baseline concentration in any area.

The modeled concentrations used to determine compliance with any NAAQS and PSD increment depend on 1) the type of standard, i.e., deterministic or statistical, 2) the available length of record of meteorological data, and 3) the averaging time of the standard being analyzed. When the analysis is based on 5 years of National Weather Service meteorological data, the following estimates are used:

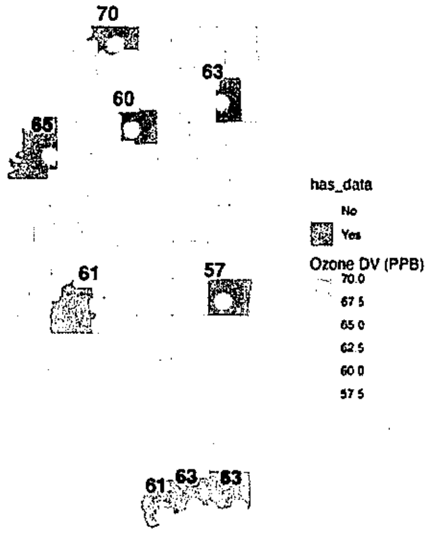
- ***For deterministically based standards (e.g., SO_2), the highest, second-highest short term estimate and the highest annual estimate; and***
- ***For statistically based standards (e.g., PM_{10}), the highest, sixth-highest estimate and highest 5-year average estimate.***

A. Existing Air Quality

Primary and Secondary 8-Hour Standard- 70 ppb

The 8-hour standard is met when the 3-year average of the annual fourth highest daily maximum 8-hour average concentration (also known as the design value) is less than or equal to 0.070 parts per million (ppm) or 70 parts per billion (ppb).

Ozone 2023 Design Value



Ozone Site	County	Year	2023 DV
Cleveland Delta State	Bolivar	2023	65
Hernando	DeSoto	2023	70
Waveland	Hancock	2023	61
Gulfport Youth Court	Harrison	2023	63
Hinds CC	Hinds	2023	59
Jackson NCORE	Hinds	2023	61
Pascagoula	Jackson	2023	63
Meridian	Lauderdale	2023	57
TUPELO AIRPORT NEAR OLD NWS OFFICE	Lee	2023	63
Coffeeville	Yalobusha	2023	60

and secondary $PM_{2.5}$. The first tier involves the use of existing technical information to evaluate the relationships between precursor emissions and a source's impacts. The second tier involves the application of more sophisticated case-specific chemical transport models (CTMs) (e.g., photochemical grid models).

Using the Tier I Demonstration approach for PSD compliance, the emissions of the individual precursor pollutants are not added together to determine if there is an exceedance but looked at individually. If an exceedance occurs for one individual precursor, the precursor pollutants are compared to the hypothetical source's modeled emission rate and impacts (MERPs). The EPA provides access to its MERPs values on its MERPs VIEW Qlik website (https://www.epa.gov/scram/merps-view-qlik). If there is an exceedance of an individual precursor, then upon calculating the potential impacts, all precursors of either ozone or $PM_{2.5}$ are taken into consideration when calculated.

Should the Tier I Demonstration find the critical air quality threshold, or significant impact level (SIL), would not be exceeded when considering the impact of the ozone-precursor emissions of VOC and NOx, the proposed project will not cause ozone concentrations exceeding the ozone SIL. No further analysis or modeling will be required.

Ozone

The Tier I Demonstration for Entergy Mississippi, LLC – Delta Blues Advanced Power Station proposed project of constructing new natural gas-fired combined cycle power plant has an anticipated increase of 1.684 ppb.

These results were obtained by using the EPA's Smith County hypothetical source (CUS 9) is located within the same airshed as the DBAPS. The majority of project-related NO_X, SO_2, and VOC emissions exhaust through the 61-meter-tall stack. This height is more similar to the "High" (90-meter) hypothetical source than the "Low" (10-meter) hypothetical source. The "High" Smith County hypothetical source MERP values were used for this analysis. The proposed project includes an (annualized daily) increase of 313 tons per year (tpy) NO_X emissions and 56 tpy SO_2 emissions. These emissions are closer to the modeled emissions for the EPA's 500 tpy hypothetical source than the EPA's 1,000 tpy or 3,000 tpy hypothetical source emission rates. The 500 tpy NO_X and SO_2 hypothetical source MERP values were used for this analysis. The proposed project includes an (annualized daily) increase 883 tpy VOC emissions. These emissions are closer to the modeled emissions for the EPA's 1,000 tpy hypothetical source than the EPA's 500 tpy or 3,000 tpy hypothetical source emission rates. The

- *100-meter spaced receptors to a distance of 1 km from the DBAPS fence line,*
- *25-meter spaced receptors to a distance of 300 meters from any DBAPS fence line and*
- *25-meter spaced receptors along the DBAPS fence line.*

Meteorological Data

Current MDEQ guidance was followed concerning meteorological data for AERMOD modeling for sources located in Washington County. The MDEQ has created county-specific preprocessed meteorological data sets using AERMET for use in AERMOD air dispersion modeling. Pre-processed meteorological data was obtained from the MDEQ. Washington County is located within the Lower Delta regions of the State. Pre-processed meteorological data consisted of surface data from the Mid Delta Regional Airport meteorological station (KGLH) and upper air data from the Jackson International station. The MDEQ processed the data using AERMET version 22112 and incorporates the AERMINUTE data along with the low wind speed threshold of 0.5 m/s. The most recent five years of representative NWS meteorological data available from the MDEQ on the date of the AQA (2018, 2019, 2020, 2021, and 2022) will be utilized in the NAAQS and PSD increment analyses. The base elevation for the Mid Delta Regional Airport station is 37.7 meters.

TABLE 6-1 SURFACE CHARACTERISTICS

POLLUTANT	ALBEDO	BOWEN RATIO	SURFACE ROUGHNESS LENGTH (m)
DBAPS	0.15	0.28	0.106
Mid Delta Regional Airport	0.18	0.51	0.024

The surface characteristics at the DBAPS are similar to those at the Mid Delta Regional Airport. The available surface roughness lengths can vary between 0.001 m to 1.5 meters. The surface roughness at these locations are both at the lower end of this range. Additionally, surface roughness at most airports are lower than non airport locations due to the runway surfaces.

Additionally, the Mid Delta Regional Airport is the nearest surface station to the DBAPS. Both the surface station and the DBAPS are located in Greenville, Mississippi. The land use immediately surrounding each location is rural in nature. The terrain surrounding each location and the

Modeled Emission Rates

MAXIMUM DAILY EMISSION RATE ESTIMATES
DELTA BLUES ADVANCED POWER STATION
GREENVILLE, MISSISSIPPI

EPN	Description	Maximum Hourly			Operations	Maximum Daily			Daily Annualized		
		NOX (lb/hr)	SO2 (lb/hr)	VOC (lb/hr)	(hr/day)	NOX (lb/day)	SO2 (lb/day)	VOC (lb/day)	NOX (TPY)	SO2 (TPY)	VOC (TPY)
SPS-1A	Combined Cycle Unit 1A - Full Load	40.59	13.98	10.62	21.9	888.9	306.2	232.5	162.2	55.88	42.43
SPS-1A	Combined Cycle Unit 1A - MSS	294.00		2,527	2.10	800	0	4,600	146.00	0	839.5
SPS-NGDPHTR	Natural Gas Dewpoint Heater	0.0399	0.00363	0.02902	24	0.9577	0.08707	0.6965	0.1748	0.01589	0.1271
SPS-EMGEN	Standby Generator	25.76	0.0338	2.6914	1	25.76	0.03385	2.691	4.701	0.006177	0.4912
SPS-FWP	Diesel Fire Water Pump	1.715	0.003150	0.05699	1	1.715	0.003150	0.05699	0.3130	0.0005750	0.01040
SPS-LOVCT	Combustion Turbine Lube Oil Vent			0.003025179	24			0.07260			0.01325
SPS-LOVST	Steam Turbine 1 Lube Oil Vent			0.003025179							
TOTAL									313.4	55.90	882.6

C. *Air Quality Monitoring Requirements*

The ambient air quality analysis is required to contain continuous air quality monitoring data. This data is gathered for purposes of determining whether emissions of any pollutant would cause or contribute to a violation of the standard or any maximum allowable increase. The facility must establish existing air quality in the area and air monitoring is required for each criteria pollutant that is proposed to be emitted at or above the de minimis. This requirement can be satisfied by either: 1) establishing a site-specific ambient monitoring network, or 2) using existing ambient monitoring data. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring de minimis concentration, MDEQ has the discretionary authority to exempt an applicant from preconstruction ambient monitoring.

Preconstruction de Minimus Chart

TABLE 12-4 PSD PRE-CONSTRUCTION MONITORING REQUIREMENT ANALYSIS RESULTS

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS AT EACH RECEPTOR (ug/m³)		SIGNIFICANT MONITORING CONCENTRATION (μg/m³)
NO_2	Annual	1st High (of 5 Years)	0.8679	14
CO	8-Hour	1st High (of 5 Years)	1.17.4	575
PM_{10}	24-Hour	1st High (of 5 Years)	1.462	10

No de minimis air quality level is provided for ozone. However, any net emissions increase of 100-tpy or more of VOC or NOx (the precursors for ozone formation) make the proposed PSD project required to perform an ambient impact analysis, including the gathering of ambient air quality data. The proposed project has a proposed emissions increase of 882.6 tpy VOC and 313.4 tpy NOx. Since the proposed project VOC emissions does exceed 100 tpy, Delta Blues must establish existing air quality in the facility project area. To meet this requirement, Delta Blues proposes to use an existing air quality monitor as opposed to establishing their own site-specific ambient monitoring network.

Ambient Air

Estimates for the current ambient air background concentrations at the proposed project site may be required for two distinct and separate purposes: (1) to demonstrate that the ambient air concentrations of PSD-significant pollutants are currently in compliance with the NAAQS and (2) for use in a full impact NAAQS modeling analysis. Based on draft Preliminary Impact Determination results, background ambient air concentration data may be required for 24-hour

Summary of Nearby Power Generating Facilities

Location	Distance to Location (km)	State	Plant Name	Plant nameplate capacity (MW)	Plant annual emissions (tons)	
					NOX	SO2
Delta Blues Project	2	MS	Gerald Andrus	781.4	263.199	0.676
	43	AR	Clearwater Paper APP CB	28	49.974	129.89
	81	AR	Georgia-Pacific Crossett LLC	25	24.276	0.465
	85	MS	CF Industries Yazoo City Complex	25	125.434	1.378
	95	MS	International Paper Vicksburg Mill	50.5	75.334	231.024
	TOTAL			910	538	363
Cleveland Monitor	47	AR	Clearwater Paper APP CB	28	49.974	129.89
	51	MS	Crossroads Energy Center (CPU)	306.4	14.647	0.297
	51	MS	L L Wilkins	55.2	0.168	0.002
	57	MS	Gerald Andrus	781.4	263.199	0.676
	99	MS	Batesville Generation Facility	891	319.832	7.39
	100	MS	CF Industries Yazoo City Complex	25	125.434	1.378
	TOTAL			2,087	773	140
Crossett Monitor	3	AR	Georgia-Pacific Crossett LLC	25	24.276	0.465
	50	LA	Ouachita Plant	903.9	160.433	6.235
	50	LA	Sterlington	59.3	22.635	0.03
	50	LA	Perryville Power Station	824.1	123.523	4.824
	63	AR	Union Power Station	2428	495.263	24.376
	75	LA	Plant 31 Paper Mill	84.2	226.698	590.1
	80	MS	Gerald Andrus	781.4	263.199	0.676
	91	AR	Clearwater Paper APP CB	28	49.974	129.89
	92	AR	McClellan	136	32.69	70.158
	95	LA	Louisiana Tech University Power Plant	7.5	37.047	0.38
	TOTAL			5,277	1,436	827

D. *PSD Preliminary Analysis Modeling Impacts*

In the preliminary analysis, only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emission increase of a pollutant from a proposed modification is modeled. A full impact analysis for a particular pollutant is not required when emissions of that pollutant from a proposed source or modification would not increase ambient concentrations by more than prescribed significant ambient impact levels.

In accordance with the Revisions to the Guideline on Air Quality Models (40 CFR Part 51, Appendix W) EPA recommends that an applicant use a "two-tiered" demonstration approach to address single-source impacts on ozone and secondary $PM_{2.5}$. The first tier involves the use of existing technical information to evaluate the relationships between precursor emissions and a source's impacts. The second tier involves the application of more sophisticated case-specific chemical transport models (CTMs) (e.g., photochemical grid models). The April 30, 2019, Memorandum, "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program", reflected EPA's recommendations on how to conduct an air quality modeling and related technical analyses to satisfy compliance demonstration requirements for Ozone and Secondary $PM_{2.5}$ for permit related assessment under the PSD Program.

For ozone, the modeled air quality impact of an increase in precursor emissions from the hypothetical source is expressed in units of ppb or ppm. Consistent with the modeled emissions rates that are input to the air quality model to predict a change in pollutant concentration, MERPs are expressed as an annual emissions rate in tons per year (tpy).

A Tier 1 approach was used to estimate the secondary $PM_{2.5}$ and O_3 impacts associated with the precursor emissions. The secondary $PM_{2.5}$ and ozone impacts were estimated using guidance from the EPA's Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1

$$\left[\left(\frac{NOx\ Increase\ (tpy)}{NOx\ MERP\ (tpy)}\right) + \left(\frac{VOC\ Increase\ (tpy)}{VOC\ MERP\ (tpy)}\right)\right] < 1$$

The recommended ozone SIL of 1-ppb was chosen to represent the critical air quality threshold. The SIL represents a de-minimis impact level, that is, if the maximum concentration of ozone due to a single source is less than the SIL, then it can be concluded that the source has an insignificant contribution to ozone formation. The hypothetical source's modeled emission rate and impacts along with the ozone SIL were used to calculate the MERPs values below:

$$Modeled\ Air\ Quality\ Impact = (Critical\ Air\ Quality\ Threshold)\left(\frac{Project\ Emissions}{MERP}\right)$$

$$Modeled\ Air\ Quality\ Impact = (1ppb\ ozone)\left[\left(\frac{882.6\ TPY\ VOC}{15{,}524\ TPY\ VOC}\right) + \left(\frac{313.4\ TPY\ NOx}{192.6\ TPY\ NOx}\right)\right]$$

$$Modeled\ Air\ Quality\ Impact = 1.684\ ppb\ ozone$$

The modeled Air Quality Impact is not below the Ozone significant impact level. The proposed project will cause ozone concentrations exceeding the recommended significant impact level for ozone. Further analysis is required.

$PM_{2.5}$ Secondary Impact Assessment

$PM_{2.5}$ 24-Hour

SO_2 MERP Calculation:

$$1.2\ ug/m\text{^}3\ \left(\frac{Selected\ Hyopthetical\ MERP)}{MaxConc}\right)$$

$$1.2\ ug/m\text{^}3\left(\frac{500\ tpy}{0.1923024058\ ug/m\text{^}3}\right)$$

$$= 3{,}120.09\ tpy$$

NOx MERP Calculation:

$$1.2\ ug/m\text{^}3\ \left(\frac{Selected\ Hyopthetical\ MERP)}{MaxConc}\right)$$

$$1.2\ ug/m\text{^}3\left(\frac{500\ tpy}{0.0461239107\ ug/m\text{^}3}\right)$$

$$= 13{,}008.44\ tpy$$

Modeled Air Quality Impact

$$= (\text{Critical Air Quality Threshold})\left(\frac{\text{Project Emissions}}{\text{MERP}}\right)$$

$Modeled\ PM_{2.5}$ Annual Air Quality Impact

$$= \left(0.13\frac{ug}{m^3}\right)\left[\left(\frac{55.9\text{ TPY }SO_2}{8{,}653\text{ TPY }SO_2}\right)+\left(\frac{313.4\text{ TPY }NO_x}{33{,}702.89\text{ TPY }NO_x}\right)\right]$$

$$\text{Modeled } PM_{2.5} \text{ Annual Hour Air Quality Impact} = 0.002049\frac{ug}{m^3}$$

$$Base\ Modeling + Secondary\ Impact =$$

$$0.1211\frac{ug}{m3} + 0.002049\frac{ug}{m3}$$

$$= 0.1231\frac{ug}{m3}$$

This value is below the SIL of 0.13 ug/m3. Therefore no further analysis is required.

$PM_{2.5}$ At and Past 50+ km

$PM_{2.5}$ 24-Hour

SO_2 MERP Calculation:

$$SIL\ \left(\frac{Selected\ Hyopthetical\ MERP)}{MaxConc}\right)$$

$$0.27\ ug/m\text{^}3\left(\frac{500\ tpy}{0.114196\ tpy}\right)$$

$$= 1{,}182.96944609\ tpy$$

NOx MERP Calculation:

$$0.27\ ug/m\text{^}3\ \left(\frac{Selected\ Hyopthetical\ MERP)}{MaxConc}\right)$$

$$0.27\ ug/m\text{^}3\left(\frac{500\ tpy}{0.045347\ ug/m\text{^}3}\right)$$

$$= 2{,}977.04368536\ tpy$$

$$Modeled\ PM_{2.5}\ \text{Annual Air Quality Impact} = \left(0.03\,\frac{ug}{m^3}\right)\left[\left(\frac{55.9\ \text{TPY}\ SO_2}{3{,}796.51\ \text{TPY}\ SO_2}\right) + \left(\frac{313.4\ \text{TPY}\ NO_x}{10{,}259.92\ \text{TPY}\ NO_x}\right)\right]$$

$$\text{Modeled}\ PM_{2.5}\ \text{Annual Hour Air Quality Impact} = 0.0013581\,\frac{ug}{m^3}$$

This value is below the SIL of 0.03 ug/m3. Therefore no further analysis is required.

Increment Consumption

PSD increment consumption limits currently exist for NO_2, SO_2, PM_{10}, and $PM_{2.5}$. Compliance with the PSD increment consumption limits must be demonstrated for sources with PSD significant emissions.

A preliminary impacts determination was first conducted using project-related emissions to determine if a detailed PSD increment consumption analysis is required. A full impact analysis was then performed for applicable NO_2, PM_{10}, and $PM_{2.5}$ emissions for comparison to the PSD increment consumption limits. This analysis will include PSD increment-consuming emissions from sitewide DBAPS sources and from PSD increment-consuming emission sources affecting the project's impact area. The full impact modeling analysis utilized receptor grids following the MDEQ guidelines. Only receptors with predicted concentrations equal to or greater than the SIL in the preliminary modeling analysis were used.

A preliminary impact determination is conducted to determine if the predicted off property concentrations associated with the proposed increase in PSD-significant emissions are greater than the EPA's SILs. No further modeling is required to demonstrate compliance if the maximum predicted concentration is below the SIL.

If the maximum predicted concentration is equal to or greater than the SIL, all on site sources must be included in a full impact modeling analysis. Contributions from off-site sources that may impact the AOI are accounted for using ambient air monitoring data or by direct inclusion in the full impact modeling analysis. The AOI is defined as all locations with predicted concentrations that are equal to or greater than the established SILs. An ambient background concentration is added to the full impact modeling results to complete the NAAQS demonstration.

Preliminary impact determination modeling was conducted for PSD-significant emissions of NO_X, CO, PM_{10}, and $PM_{2.5}$ to determine whether a full impact modeling analysis is required for each pollutant and averaging period. The modeling results were used to determine whether the predicted concentrations are greater than the SIL for each pollutant and averaging period. The estimated ozone impacts obtained using the MERP analysis was used to determine whether a full impact modeling analysis is required for this pollutant. The MERP results were used to determine whether the project-related impacts are greater than the SIL.

all nearby sources as part of the NAAQS analysis. The modeling guideline defines a "nearby" source as any point source expected to cause a significant concentration gradient in the vicinity of the proposed new source or modification. For PSD purposes, "vicinity" is defined as the impact area. The location of such nearby sources could be anywhere within the impact area or an annular area extending 50 kilometers beyond the impact area.

Based on the results of the draft preliminary impact determination, full impact NAAQS modeling analyses are expected to be required for 8-hour O_3. The form of the predicted ground-level concentrations from the NAAQS modeling, the form of the background concentrations, and the NAAQS for all applicable criteria pollutants are summarized in Table 12-6. The predicted ground-level concentrations from the NAAQS modeling, the background concentrations for the project area, and the sum of the two values will be summarized in Table 12-7. The total impacts are compared to the NAAQS.

TABLE 12-6 NAAQS ANALYSIS – FORM OF MODELING RESULTS AND BACKGROUND CONCENTRATION

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS (PPB)	BACKGROUND CONCENTRATION (PPB)	NAAQS (PPB)
O_3	8-Hour	Conservative Maximum (from MERP analysis)	3-Year Average of the 4th Highest Daily 8-Hour Maximums	70

TABLE 12-7 NAAQS ANALYSIS RESULTS

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS (PPB)	BACKGROUND CONCENTRATION (PPB)	TOTAL (PPB)	NAAQS (PPB)
O_3	8-Hour	1.684 [a]	65	66.68	70

[a] Estimated secondary O_3 impact from Section 12.1.1 MERP analysis

<u>Ozone NAAQS Cumulative Analysis</u>

$$NAAQS\ Value > Modeled\ Air\ Quality\ Impact + Monitered\ Design\ Value$$

$$70ppb > 1.684\ ppb + 65\ ppb$$

$$70ppb > 66.68\ ppb$$

The air quality level is less than the NAAQS, therefore no NAAQS violation is found, and the facility does not cause or contribute to a violation.

<u>$PM_{2.5}$ NAAQS</u>

<u>24-hour</u>:

$$5\ Year\ Average\ of\ First\ High + Secondary\ Impact =$$

TABLE 12-1 MERP ANALYSIS RESULTS, MAXIMUM

POLLUTANT	AVERAGING PERIOD	ESTIMATED MERP CONCENTRATION ($\mu g/m^3$)
$PM_{2.5}$	24-HOUR	0.05041
	ANNUAL	0.002049
O_3	8-HOUR	1.684 PPB

TABLE 12-2 MERP ANALYSIS RESULTS, AT 50+ KM

POLLUTANT	AVERAGING PERIOD	ESTIMATED MERP CONCENTRATION ($\mu g/m^3$)
$PM_{2.5}$	24-HOUR	0.04199
	ANNUAL	0.001358

TABLE 12-8 PSD INCREMENT CONSUMPTION ANALYSIS RESULTS

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS AT EACH RECEPTOR ($\mu g/m^3$)		PSD INCREMENT CONSUMPTION LIMIT ($\mu g/m^3$)
$PM_{2.5}$	24-Hour	2nd High (of 5 Years)	1.192 *	9

* Includes estimated secondary $PM_{2.5}$ impact from Section 12.1.1 MERP analysis

The $PM_{2.5}$ 24-hour Increment Results show that the Maximum Predicted Concentration of 1.192 ug/m3 is less that the PSD Increment of 9 ug/m3. This shows that there is no violation, and no further analysis is needed.

F. Vegetation and Soils Impact

VOCs are regulated as precursors to tropospheric ozone. Elevated ground-level ozone concentrations can damage plant life and crop production. VOCs interfere with the ability of plants to produce and store food, making them more susceptible to disease, insects, or other pollutants and harsh weather. Ozone is formed by the interaction of NOx, VOCs, and sunlight in the atmosphere. The effect of a proposed project's emissions on local soils and vegetation is often addressed through comparison of modeled impacts to the secondary NAAQS. The secondary NAAQS were established to protect general public welfare and the environment. Impacts below the secondary NAAQS are assumed to indicate a lack of adverse impacts on soils and vegetation.

The emissions from the proposed modification will not significantly affect any soils or vegetation within the area (i.e., the modeling domain). There are no predicted exceedances of the Primary or Secondary NAAQS due to the proposed emissions. Primary NAAQS set limits to protect public health, with an adequate margin of safety. "Public health" is defined to include the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary NAAQS set limits to protect public welfare from any known or anticipated adverse effects associated with the presence of such a pollutant. "Public welfare" includes protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Therefore, possible adverse impacts from this project are not expected.

TABLE 12-5 PSD CLASS I INCREMENT NEAR FIELD ASSESSMENT ANALYSIS RESULTS

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS AT EACH RECEPTOR (ug/m³)		SIGNIFICANT IMPACT LEVEL (SIL) (µg/m³)
NO_2	Annual	1st High (of 5 Years)	0.009010	0.1
PM_{10}	24-Hour	1st High (of 5 Years)	0.1318	0.3
	Annual	1st High (of 5 Years)	0.007050	0.2
$PM_{2.5}$	24-Hour	1st High (of 5 Years)	0.1730 *	0.27
	Annual	1st High (of 5 Years)	0.008408 *	0.03

* Includes estimated secondary $PM_{2.5}$ impact from Section 12.1.1 MERP analysis

The predicted NO_2, PM_{10}, and $PM_{2.5}$, concentrations are less than their respective Class I PSD increment SILs. No additional modeling is required for these pollutants.

A) Class II Impact and Visibility

EML has extensive experience operating natural gas-fired combustion turbine Electric Generating Units (EGUs) at numerous locations. Because low-sulfur pipeline-quality natural gas is such a clean burning fuel, to the best of EML's knowledge there has never been a circumstance where operation of such an EGU has resulted in visibility impairment at any on-site or off-site receptor or area. This statement is true for routine operations as well as maintenance, startup, and shutdown operations of EML's combustion turbine EGUs. The emissions of visibility impairing pollutants, including sulfates, NOx, and PM/soot, are very low because (1) clean burning low sulfur pipeline quality gas will be fired and (2) state-of-the art emission controls will be employed.

Based on EML's extensive experience operating natural gas-fired combustion turbine EGUs, EML is confident in asserting that the Delta Blues Advanced Power Station will not cause or contribute to visibility impairment at any off-site receptor or area, including all nearby airports, state forests, parks, scenic vistas, areas of special historic interest, or any other sensitive areas.

VI. Recommendation

The staff of the Permit Board has developed the draft permit and preliminary determination based on information submitted to the Permit Board by the applicant. The staff of the Permit Board is soliciting all relative information pertaining to the proposed activity, including a 30-day public comment, EPA review, and FLM review, to ensure that the final staff recommendation on the draft permit complies with all State and Federal regulations. The Public, EPA, and FLM review and comment on the draft permit and supporting documentation is an important element in the staff evaluation and resulting recommendation to the Permit Board. After a thorough consideration of the expressed views of all interested persons, pertinent federal/state statutes and regulations, supplemental information/modeling submitted by Cooperative Energy, a Mississippi Electric Cooperative, R.D. Morrow, Sr., Generating Plant any additional material relevant to the application, and after an appropriate resolution of all the comment, will MDEQ staff recommend issuance of the proposed/final draft PSD permit to Construct in accordance with 11 Miss. Admin. Code Pt. 2 - Air Regulations, 40 CFR Part 52.21 – Prevention of Significant Deterioration of Air Quality, and 40 CFR 51 Appendix W – Guidelines on Air Quality Models. The draft permit conditions have been developed to ensure compliance with all State and Federal regulations but are subject to change based on information received as a result of public, EPA, and FLM participation.

SECTION 2

COPY OF THE CONSTRUCTION PERMIT

STATE OF MISSISSIPPI
AIR POLLUTION CONTROL PERMIT

AND PREVENTION OF SIGNIFICANT DETERIORATION (PSD) AUTHORITY

TO CONSTRUCT AIR EMISSIONS EQUIPMENT

THIS CERTIFIES THAT

Entergy Mississippi LLC, Delta Blues Advanced Power Station
221 Stokes King Road
Greenville, Mississippi
Washington County

has been granted permission to construct air emissions equipment to comply with the emission limitations, monitoring requirements and other conditions set forth herein. This permit is issued in accordance with 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 and under authority granted by the Environmental Protection Agency under 40 CFR 52.01 and 52.21.

MISSISSIPPI ENVIRONMENTAL QUALITY PERMIT BOARD

Becky Simonson

AUTHORIZED SIGNATURE
MISSISSIPPI DEPARTMENT OF ENVIRONMENTAL QUALITY

Issued: **April 16, 2025** **Permit No.: 2800-00142**

86260 PER20240001

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 permit or, for information claimed to be confidential, the permittee shall furnish such records to the MDEQ 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. 2.2.B(15)(d).)

1.10 *Design and Construction Requirements:* The stationary source shall be designed and constructed so as to operate without causing a violation of any Applicable Rules and Regulations, without interfering with the attainment and maintenance of State and National Ambient Air Quality Standards, and such that the emission of air toxics does not result in an ambient concentration sufficient to adversely affect human health and well-being or unreasonably and adversely affect plant or animal life beyond the stationary source boundaries.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.A(1)-(3).)

1.11 The necessary facilities shall be constructed to prevent any wastes or other products or substances to be placed in a location where they are likely to cause pollution of the air or waters of the State without the proper environmental permits.

(Ref.: Miss. Code Ann. 49-17-29(1) and (2))

1.12 *Fugitive Dust Emissions from Construction Activities:* The construction of the stationary source shall be performed in such a manner so as to reduce fugitive dust emissions from construction activities to a minimum.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.A(4).)

1.13 *General Nuisances:* 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.)

1.19 *Permit Expiration:* The permit to construct will expire if construction does not begin within eighteen (18) months from the date of issuance, if construction is suspended for eighteen (18) months or more, or if construction is not completed within a reasonable time. The DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.C(1)., R. 2.5.C(4)., and R. 5.2.)

1.20 *Certification of Construction:* A new stationary source issued a Permit to Construct cannot begin operation until certification of construction by the permittee.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.D(3).)

1.21 *Beginning Operation:* After certification of construction by the permittee, the Permit to Construct shall be deemed to satisfy the requirement for a permit to operate until the date the application for issuance or modification of the Title V Permit or the application for issuance or modification of the State Permit to Operate, whichever is applicable, is due. This provision is not applicable to a source excluded from the requirement for a permit to operate as provided by 11 Miss. Admin. Code Pt. 2, R. 2.13.G.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.D(4).)

1.22 *Application for a Permit to Operate:* The application for issuance or modification of the State Permit to Operate or the Title V Permit, whichever is applicable, is due twelve (12) months after beginning operation or such earlier date or time as specified in the Permit to Construct. The Permit Board may specify an earlier date or time for submittal of the application. Beginning operation will be assumed to occur upon certification of construction, unless the permittee specifies differently in writing.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.D(5).)

1.23 *Operating Under a Permit to Construct:* Upon submittal of a timely and complete application for issuance or modification of a State Permit to Operate or a Title V Permit, whichever is applicable, the applicant may continue to operate under the terms and conditions of the Permit to Construct and in compliance with the submitted application until the Permit Board issues, modifies, or denies the Permit to Operate.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.D(6).)

1.24 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

(3) Where an upset, as defined in 11 Miss. Admin. Code Pt. 2, R. 1.2.,occurs during startup or shutdown, see the upset requirements above.

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

1.25 *General Duty:* All air emission equipment shall be operated as efficiently as possible to minimize emissions of air contaminants.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(10).)

1.26 *Compliance Testing:* Regarding compliance testing:

(a) The results of any emissions sampling and analysis shall be expressed both in units consistent with the standards set forth in any Applicable Rules and Regulations or this permit and in units of mass per time.

(b) Compliance testing will be performed at the expense of the permittee.

(c) Each emission sampling and analysis report shall include but not be limited to the following:

(1) detailed description of testing procedures;

(2) sample calculation(s);

(3) results; and

(4) comparison of results to all Applicable Rules and Regulations and to emission limitations in the permit.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.6.B(3), (4), and (6).)

SECTION 3. EMISSION LIMITATIONS AND STANDARDS

Emission Point	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limitation/Standard
Facility-Wide	11 Miss. Admin. Code Pt. 2, R. 1.3.A	3.1	Opacity	Opacity < 40%
	11 Miss. Admin. Code Pt. 2, R. 1.3.B	3.2		Equivalent Opacity
AA-001	40 CFR 60, Subpart KKKK Standards of Performance for Stationary Combustion Turbines 40 CFR 60.4305(a), Subpart KKKK	3.3	NO_X SO_2	NSPS Applicability
	40 CFR 60.4320(a), Subpart KKKK	3.4	NO_X	15 ppm @15% O_2 or 0.43 lbs/MWh on a 30-unit operating day average
	40 CFR 60.4330(a)(2), Subpart KKKK	3.5	SO_2	0.06 lbs SO_2/MMBtu
	40 CFR 60.4333(a), Subpart KKKK	3.6	SO_2 NO_x	Minimize Emissions
	40 CFR 60, Subpart TTTTa Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units 40 CFR 60.5509a(a), Subpart TTTTa	3.7	CO_2	NSPS Applicability
	40 CFR 60.5520a(a) and Table 1, Subpart TTTTa	3.8		Emission Standard – 800 lb CO_2/MWh on a 12 operating-month average
	40 CFR 72.6, Subpart A	3.9	NO_X	Acid Rain Applicability
	11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j) **(PSD BACT Limit)**	3.10	$PM_{10}/PM_{2.5}$	**BACT**: Use low sulfur pipeline natural gas and good combustion practices to limit PM emissions to 0.0095 lb PM/MMBtu (annual average)
		3.11	NO_X	**BACT**: 2.0 ppm @ 15% O_2 (24-hour average based on 1-hour averages) not to exceed 40.59 lb/hr (excluding startup, shutdown, and tuning) and 228.79 tpy

Emission Point	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limitation/Standard
				NO_x - 5.36 g NO_x/kWh CO - 0.60 g CO/kWh
		3.25	GHG CO_2e	**BACT**: Achieve GHG performance levels specified in Tables C-1 and C-2 of 40 CFR 98
AA-002 AA-003	40 CFR 63, Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants from Reciprocating Internal Combustion Engines 40 CFR 63.6585, 63.6590(a)(2)(iii) & (c)(1), Subpart ZZZZ	3.26	HAP	NESHAP Applicability
	40 CFR 60, Subpart IIII Standards of Performance for Stationary compression Ignition Internal combustion Engines 40 CFR 60.4200(a)(2)(i), Subpart IIII	3.27	NO_x CO	NSPS Applicability
AA-002	40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), Subpart IIII 40 CFR 1039 Appendix I	3.28	NMHC NOx CO PM	Emissions Standards
AA-003	40 CFR 60.4202(a)(2), 40 CFR 60.4205(c) Table 4, Subpart IIII	3.29		
AA-002 AA-003	40 CFR 60.4207(b), Subpart IIII, and 40 CFR 1090.305	3.30	Fuel Requirement	Diesel fuel standards: a) Max sulfur content of 15 ppm, and b) Minimum cetane index of 40 or a maximum aromatic content of 35 volume percent
	40 CFR 60.4209(a), Subpart IIII	3.31	Hours of Operation	Install a non-resettable hour meter
	40 CFR 60.4211(c), Subpart IIII	3.32	NOx CO	Purchase a certified engine
	40 CFR 60.4211(f), Subpart IIII	3.33	Hours of Operation	Operating Requirements
AA-003	11 Miss. Admin. Code Pt. 2, Ch.	3.34	$PM_{10}/PM_{2.5}$	**BACT**: 0.10 g PM/kWh not to exceed 0.05 lb/hr (3-hour average) and <0.01 tpy

Emission Point	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Limitation/Standard
		3.46	GHG CO_2e	**BACT**: 1,861.77 tpy CO_2e
	11 Miss. Admin. Code Pt. 2, R. 1.4.A(1)	3.47	SO_2	4.8 lbs/MMBtu
AA-005 AA-006	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10). **(PSD BACT Limit)**	3.48	VOC	**BACT**: Employ an AVO Leak Detection program
AA-007			GHG CO_2e	
AA-008	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10). **(PSD BACT Limit)**	3.49	VOC	**BACT**: 0.01 tpy (12-month rolling total)
		3.50	$PM_{10}/PM_{2.5}$	**BACT**: 0.01 tpy (12-month rolling total)
AA-009	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10). **(PSD BACT Limit)**	3.51	VOC	**BACT**: 0.01 tpy (12-month rolling total)
		3.52	$PM_{10}/PM_{2.5}$	**BACT**: 0.01 tpy (12-month rolling total)
AA-010	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10). **(PSD BACT Limit)**	3.53	VOC	**BACT**: Fixed Roof Tank
AA-011	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10). **(PSD BACT Limit)**	3.54	VOC	**BACT**: Fixed Roof Tank

3.1 For the entire facility, 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. 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.

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

3.2 For the entire facility, except as otherwise or 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 3.1. This shall not apply to vision obscuration caused by uncombined water droplets.

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

3.10 For Emission Point AA-001, the permittee shall not discharge or cause the discharge of Particulate Matter (PM_{10} and $PM_{2.5}$) in excess of 56.66 lb/hr (24-hour rolling average based on a one-hour average) and 166.54 tpy, (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j), **BACT Limit**)

3.11 For Emission Point AA-001, the permittee shall not discharge or cause the discharge of Nitrogen Oxides (NO_x) in excess of 2.0 ppm corrected to 15 percent Oxygen (O_2), 40.59 lb/hr (excluding startup, shutdown, and tuning[1]) (24-hour rolling average based on a one-hour average), and 228.79 tpy (including startup, shutdown, and tuning) (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j) **BACT Limit**)

3.12 For Emission Point AA-001, the permittee shall not discharge or cause the discharge of Carbon Monoxide (CO) in excess of 2.0 ppm corrected to 15 percent Oxygen (O_2), 24.71 lb/hr (excluding startup, shutdown, and tuning[1]), and 1,201.65 tpy (including startup, shutdown, and tuning) determined by a 24-hour rolling averaged based on a one-hour average.

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j) **BACT Limit**)

3.13 For Emission Point AA-001, the permittee shall not discharge or cause the discharge of Volatile Organic Compounds (VOC) in excess of 1.5 ppm corrected to 15 percent Oxygen (O_2), 10.62 lb/hr (excluding startup, shutdown, and tuning[1]) (24-hour rolling average based on a one-hour average), and 405.26 tpy (including startup, shutdown, and tuning) (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j) **BACT Limit**)

3.14 For Emission Point AA-001, the permittee shall not discharge or cause the discharge of Sulfuric Acid Mist (H_2SO_4) in excess of 13.98 lb/hr (24-hour rolling average based on a one-hour average) not to exceed 30.35 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. And 40 CFR 52.21(j) **BACT Limit**)

3.15 For Emission Point AA-001, on or after the date of initial startup, the permittee shall not discharge or cause the discharge of Greenhouse Gas (GHG) emissions (CO_2(e)) in excess of 800 lbs of CO_2(e)/gross Mega Watt hour (MWh) on a 12-month rolling average not to exceed 2,651,642 tpy.

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. And 40 CFR 52.21(j) **BACT Limit**)

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[1] Per Condition 3.16

3.19 For Emission Points AA-001 and AA-002, the maximum permissible emission of ash and/or particulate matter from fossil fuel burning installations greater than 10 million BTU per hour heat input but less than 10,000 million BTU per hour heat input shall not exceed an 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).)

3.20 For Emission Point AA-002, the permittee shall not discharge or cause the discharge of Particulate Matter (PM_{10} and $PM_{2.5}$) in excess of 0.83 lb/hr (3-hour average) and 0.04 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j), **BACT Limit**)

3.21 For Emission Point AA-002, the permittee shall not discharge or cause the discharge of Nitrogen Oxides (NO_x) in excess of 25.76 lb/hr (3-hour average) and 1.29 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. And 40 CFR 52.21(j), **BACT Limit**)

3.22 For Emission Point AA-002, the permittee shall not discharge or cause the discharge of Carbon Monoxide (CO) in excess of 2.88 lb/hr (3-hour average) and 0.14 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. And 40 CFR 52.21(j), **BACT Limit**)

3.23 For Emission Point AA-002, the permittee shall not discharge or cause the discharge of Volatile Organic Compounds (VOC) in excess of 2.69 lb/hr (3-hour average) and 0.13 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. And 40 CFR 52.21(j), **BACT Limit**)

3.24 For Emission Point AA-002, the permittee shall purchase a certified engine that is certified to comply with the following emission standards.

(a) $PM_{10}/PM_{2.5}$ - 0.173g PM/kWh

(b) NO_x - 5.36 g NO_x/kWh

(c) CO - 0.60g CO/kWh

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j), **BACT Limit**)

3.25 For Emission Point AA-002, on or after the date of initial startup, the permittee shall not discharge or cause the discharge of Greenhouse Gas (GHG) emissions (CO_2(e)) in excess

The permittee will comply with these standards by complying with the BACT requirements in Conditions 3.34 through 3.38.

(Ref.: 40 CFR 60.4202(a)(2), 40 CFR 60.4205(c), and Table 4, Subpart IIII)

3.30 For Emission Points AA-002 and AA-003, the permittee shall use only diesel fuel that meets the following requirements for non-road diesel:

(a) A maximum sulfur content of 15 ppm,. and

(b) A minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

(Ref.: 40 CFR 60.4207(b), Subpart IIII and 40 CFR 1090.305)

3.31 For Emission Points AA-002 and AA-003, the permittee shall install a non-resettable hour meter prior to startup of the engines.

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

3.32 For Emission Points AA-002 and AA-003, the engines shall be certified to the emission standards in Conditions 3.28 and 3.29 and shall be installed and configured according to the manufacturer's emission-related specifications.

(Ref.: 40 CFR 60.4211(c), Subpart IIII)

3.33 For Emission Points AA-002 and AA-003, the permittee shall operate the emergency stationary ICE according to the requirements in (a) through (c) below. In order for the engines to be considered emergency stationary ICE under 40 CFR 60 Subpart IIII, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described below, is prohibited. If you do not operate the engine according to the requirements below, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.

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

(b) Emergency stationary ICE may be operated for maintenance checks and readiness testing for a maximum of a 100 hours per calendar year, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The 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 permittee maintains records indication that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

total) determined by the use of a USEPA-certified Tier 3 engine which meets the GHG performance levels specified in Tables C-1 and C-2 of 40 CFR 98.

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. And 40 CFR 52.21(j), **BACT Limit**)

3.40 For Emission Points AA-003 and AA-004, 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).)

3.41 For Emission Point AA-004, the permittee shall not discharge or cause the discharge of Particulate Matter (PM_{10} and $PM_{2.5}$) in excess of 0.02 lb/hr (3-hour average) and 0.08 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. And 40 CFR 52.21(j), **BACT Limit**)

3.42 For Emission Point AA-004, the permittee shall not discharge or cause the discharge of Nitrogen Oxides (NOx) in excess of 0.04 lb/hr (3-hour average) and 0.17 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j) **BACT Limit**)

3.43 For Emission Point AA-004, the permittee shall not discharge or cause the discharge of Carbon Monoxide (CO) in excess of 0.13 lb/hr (3-hour average) and 0.59 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j) **BACT Limit**)

3.44 For Emission Point AA-004, the permittee shall not discharge or cause the discharge of Volatile Organic Compounds (VOCs) in excess of 0.03 lb/hr (3-hour average) and 0.13 tpy (12-month rolling total).

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j) **BACT Limit**)

3.45 For Emission Point AA-004, the permittee shall adhere to good combustion practices to meet the following emissions standards:

(a) $PM_{10}/PM_{2.5}$ – 0.0048 lb PM/MMBtu

(b) NO_X – 0.011 lb NO_X/MMBtu

(c) CO – 0.037 lb CO/MMBtu

(d) VOC – 0.008 lb VOC/MMBtu

(Ref.: 11 Miss. Admin. Code Pt. 2, Ch. 5. and 40 CFR 52.21(j), **BACT Limit.**)

SECTION 4. WORK PRACTICES

Emission Point	Applicable Requirement	Condition Number(s)	Work Practice
AA-004	11 Miss. Admin. Code Pt. 2, R. 2.2.B(10).	4.1	Maintenance and Tune-Ups every 5 years

4.1 For Emission Point AA-004, the permittee shall perform tune-ups every five (5) years not to exceed 61 months from the previous tune-up. Each tune-up shall include the following:

(a) Inspect the burner, and clean or replace any components of the burner as necessary (permittee may delay the burner inspection until the next scheduled unit shutdown, but must inspect each burner at least once every 48 months);

(b) Inspect the flame pattern, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications;

(c) Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly;

(d) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specification and with any NOx 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) In lieu of performing the tune-up in accordance with A through E of this condition, the permittee can submit an alternative tune-up procedure based on the manufacturer's recommendation for approval by MDEQ at least sixty (60) days prior to the five year tune-up.

(Ref.: 11Miss. Admin. Code Pt. 2, R. 2.2.B(10).)

Emission Point	Applicable Requirement	Condition Number(s)	Pollutant/ Parameter	Monitoring/Recordkeeping Requirement
AA-001	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	5.10	GHG $CO_2(e)$	GHG Emissions Calculations
AA-001	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	5.11	$PM/PM_{10}PM_{2.5}$ $CO/NO_x/VOC$ $SO_2/H_2SO_4/GHG$	Excess Emissions and Monitor Downtime
AA-001	40 CFR 60.4333, 60.4335, 60.4345, 60.4350, 60.4355, 60.4360, 60.4365, and 60.4370, Subpart KKKK	5.12	NO_x	Monitoring and Recordkeeping
AA-001	40 CFR 60.5525a, Subpart TTTTa	5.13	CO_2	General Requirements
AA-001	40 CFR 60.5535a, Subpart TTTTa	5.14	CO_2	Excess Emissions
AA-001	40 CFR 60.5540a(a), Subpart TTTTa	5.15	CO_2	Excess Emissions
AA-001	40 CFR 60.5560a, Subpart TTTTa	5.16	CO_2	Recordkeeping
AA-001	40 CFR 60.5565a, Subpart TTTTa	5.17	CO_2	Recordkeeping
AA-002 AA-003	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	5.18	$PM_{10}/PM_{2.5}$ NO_x CO VOC	Perform a one-time stack test
AA-002 AA-003	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	5.19	$PM_{10}/PM_{2.5}$ NO_x CO VOC	Determine compliance using emission calculations
AA-002 AA-003	40 CFR 60.4206, Subpart IIII	5.20	Compliance	Maintain emissions standards
AA-002 AA-003	40 CFR 60.4211(a), Subpart IIII	5.21	Compliance	Operate and maintain according to manufacturer's written instructions
AA-002 AA-003	40 CFR 60.4211(g)(3), Subpart IIII	5.22	Compliance	Operate and maintain according to manufacturer's written instructions
AA-002 AA-003	40 CFR 60.4214(b), Subpart IIII	5.23	Compliance	Recordkeeping
AA-004	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	5.24	CO $PM/PM_{10}/PM_{2.5}$ VOC H_2SO_4 Mist	Determine compliance using vendor emissions data, work practice standards, and manufacturer's recommendations in Section 4
AA-004	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	5.25	GHG	Calculate and record $CO_2(e)$ emissions on a 12-month rolling average
AA-005 AA-006 AA-007	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	5.26	VOC GHG CO_2e	Maintain AVO plan and repairs made

5.4 For Emission Point AA-001, as soon as practicable following initial startup of the combustion turbine but prior to commencement of commercial operation, and thereafter, the permittee shall develop and implement an operation and maintenance plan. At a minimum, the plan shall identify measures for assessing the performance of the turbine, the acceptable range of the performance measures for achieving the design electrical output, the methods for monitoring the performance measures, and the routine procedures for maintaining the turbine in good operating condition.

The permittee shall maintain a copy of the current operation and maintenance plan for the facility and shall keep a copy of all prior versions of the plan for a minimum of five years. The permittee shall also keep records of the monitoring data for each of the facility performance measures and all maintenance activities; the permittee shall maintain such records for a minimum of 5 years following the date they are created.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

5.5 For Emission Point AA-001, the permittee shall demonstrate initial compliance with the CO, PM, VOC, NOx, and H_2SO_4 mist emission limits, set forth in Section 3 of this permit by stack testing in accordance with the applicable EPA Test Methods listed below or an EPA approved alternative within 180 days after startup.

Carbon Monoxide (CO)	EPA Test Method 10
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	EPA Test Methods 5 and 202
Volatile Organic Compounds (VOC)	EPA Test Method 25
Nitrogen Oxides (NO_X)	EPA Test Method 7
Sulfuric Acid Mist (H_2SO_4)	EPA Test Method 8

All test methods shall be the current versions, which are in effect upon permit issuance. The stack testing shall be performed when the emission units are operating as close to their maximum capacity as operating conditions allow.

In lieu of stack testing for H_2SO_4 mist the permittee shall obtain and maintain the fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the gaseous fuel meets the applicable sulfur limit. To demonstrate continuous compliance, the permittee shall perform a fuel gas analysis to determine the sulfur content of the natural gas once every 12-month period of operation.

In lieu of stack testing for NO_X and CO the permittee can demonstrate compliance with the emission limitations using a Continuous Emission Monitoring System (CEMS). Demonstrating compliance with the ppm, lb/hr, and tons/year limits using CEMS data in lieu of EPA Reference Methods is an acceptable practice provided the permittee meets the guidelines established in EPA's general guidance on "Alternative Testing and Monitoring Procedures for Combustion Turbines Regulated under New Source

The permittee shall also maintain records that include the following: the occurrence and duration of any startup, shutdown, tuning, shakedown, or malfunction, performance testing, evaluations, calibrations, checks, adjustments, maintenance, duration of any periods during which a continuous monitoring system or monitoring device is inoperative, and corresponding emission measurements.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

5.10 For Emission Point AA-001, for demonstration compliance with the limits in Condition 3.15, the permittee shall use the procedures set forth in 40 CFR 75 and 98 to determine resulting GHG emissions as CO_2(e) based on the calculated CO_2 emissions (from hourly heat input data) and calculated CO_2(e) of other GHG pollutants. The permittee shall keep adequate records of these GHG emission calculations.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

5.11 For Emission Point AA-001, the permittee shall maintain records of all excess emissions. Excess emissions shall be defined as any period in which the emissions exceed the maximum emission limits set forth in this permit. A period of monitoring down-time shall be any unit operating hour in which sufficient data was not obtained by the CEMS to validate the hour according to 40 CFR 75. Excess emissions indicated by the CEMS system, source testing, or compliance monitoring shall be considered violation of the applicable emission limit.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

5.12 For Emission Point AA-001, the permittee shall comply with all applicable monitoring and recordkeeping as described in 40 CFR 60, Subpart KKKK.

(Ref.: 40 CFR 60.4333, 60.4335, 60.4345, 60.4350, 60.4355 60.4360, 60.4365, and 60.4370, Subpart KKKK)

5.13 For Emission Point AA-001, compliance with the applicable CO_2 emission standard in Condition 3.15 shall be determined on a 12-operating-month rolling average basis.

(a) The permittee shall be in compliance with the emission standards in 40 CFR 60, Subpart TTTTa that apply to the EGU at all times. For each affected EGU, the permittee shall determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period. However, the permittee shall determine compliance with the emission standards only at the end of the applicable operating month, as provided in (1) and (2) below.

(1) At all times, the permittee shall operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The MDEQ will determine if you are using consistent operation and maintenance procedures based on information available to the DEQ that may include, but is not limited to,

(b) The permittee shall install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU. These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010.

(Ref.: 40 CFR 60.5535a(a), (c)(1 through 4), Subpart TTTTa)

5.15 For Emission Point AA-001, for the initial and each subsequent 12-operating-month rolling average compliance period, to demonstrate compliance with Condition 3.15, the permittee shall follow the procedures in paragraphs 40 CFR 60.5540a(a)(1) through (8) to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*i.e.,* either kg/MWh or lb/MMBtu). The permittee shall use the hourly CO_2 mass emissions calculated under Condition 5.14(a), as applicable, and the generating load data from Condition 5.14(b) for output-based calculations. The CO_2 mass emissions rate for Emission Point AA-001 must be determined according to the procedures specified in 40 CFR 60.5540a(a) (1) through (8) and must be less than or equal to the applicable CO_2 emission standard in Condition 3.15.

(Ref.: 40 CFR 60.5540a(a), Subpart TTTTa)

5.16 For Emission Point AA-001, the permittee shall comply with the following recordkeeping requirements:

(a) Maintain records of the information used to demonstrate compliance with 40 CFR 60, Subpart TTTTa as specified in 40 CFR 60.7(b) and (f).

(b) For affected EGUs subject to the Acid Rain Program, the permittee shall follow the applicable recordkeeping requirements and maintain records as required under 40 CFR 75, Subpart F.

(c) Keep records of the calculations performed to determine the hourly and total CO_2 mass emissions (tons) for each operating month (for all affected EGUs); and each compliance period, including each 12-operating-month compliance period.

(d) Keep records of the applicable data recorded and calculations performed that were used to determine the affected EGU's gross or net energy output for each operating month.

(e) Keep records of the calculations performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) Keep records of the calculations performed to assess compliance with each applicable CO_2 mass emissions standard in Condition 3.15.

(g) Keep records of the calculations performed to determine any site-specific carbon-based F-factors you used in the emissions calculations.

(c) Meet the requirements of 40 CFR parts 89, 94, and/or 1068, as they apply.

(Ref.: 40 CFR 60.4211(a), Subpart IIII)

5.22 For Emission Points AA-002 and AA-003, if the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the emission-related settings are changed in a way that is not permitted by the manufacturer, the permittee shall demonstrate compliance as follows: the permittee shall keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, the permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(Ref.: 40 CFR 60.4211(g)(3), Subpart IIII and 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

5.23 For Emission Points AA-002 and AA-003, the permittee shall keep records of the hours of operation of the engines in emergency and non-emergency service that are recorded through the non-resettable hour meter. The records shall indicate 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.: 40 CFR 60.4214(b), Subpart IIII)

5.24 For Emission Point AA-004, the permittee shall determine compliance with the BACT Limits using vender emissions data, work practice standards, and manufacturer's recommendations outlined in Condition 4.1.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

5.25 For Emission Point AA-004, the permittee shall use the annual heat input and data from 40 CFR 98, Table C-1 to calculate and record CO_2(e) emissions on a 12-month rolling average using the Global Warming Potential factors in Condition 5.3.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

5.26 For Emission Points AA-005, AA-006, and AA-007, the permittee shall record and maintain a log of daily AVO inspections, and any repairs made to the fugitive sources.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

SECTION 6. REPORTING REQUIREMENTS

Emission Point	Applicable Requirement	Condition Number(s)	Reporting Requirement
Facility-Wide	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	6.1(a)	Report deviations within five (5) working days
	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	6.1(b)	Semiannual reporting
	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	6.1(c)	Certification by responsible official
	11 Miss. Admin. Code Pt. 2, R. 2.5.C(2).	6.1(d)	Notification of beginning actual construction within 15 days
	11 Miss. Admin. Code Pt. 2, R. 2.5.C(3).	6.1(e)	Notification when construction does not begin or is suspended
	11 Miss. Admin. Code Pt. 2, R. 2.5.D(1) and (3).	6.1(f)	Certification of completion of construction prior to operation
	11 Miss. Admin. Code Pt. 2, R. 2.5.D(2).	6.1(g)	Notification of changes in construction
	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	6.2	Submit stack test protocol 30 days prior to conducting the stack test
		6.3	Submit a stack test report within 60 days of conducting the stack test
AA-001	11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).	6.4	Semi-annual reporting
		6.5	Submit records of startup, shutdown, and tuning events
		6.6	Submit monitoring plan in accordance with 40 CFR 75.62
		6.7	Notification in 40 CFR 75.61
		6.8	Excess Emissions
	40 CFR 60.4375(b), Subpart KKKK	6.9	Subpart KKKK Reporting
	40 CFR 60.5550a(a), Subpart TTTTa	6.10	Submit notifications specified in 40 CFR 60.7(a)(1) and (3), and 60.19 and Table 3
	40 CFR 60.5550a(b), Subpart TTTTa	6.11	Submit notifications specified in 40 CFR 75.61
	40 CFR 60.5555a(a), Subpart TTTTa	6.12	Reporting Requirements

(d) Within fifteen (15) days of beginning actual construction, the permittee must notify DEQ in writing that construction has begun.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.C(2).)

(e) The permittee must notify DEQ in writing when construction does not begin within eighteen (18) months of issuance or if construction is suspended for eighteen (18) months or more.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.C(3).)

(f) Upon the completion of construction or installation of an approved stationary source or modification, and prior to commencing operation, the applicant shall notify the Permit Board that construction or installation was performed in accordance with the approved plans and specifications on file with the Permit Board.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.D(1) and (3).)

(g) The Permit Board shall be promptly notified in writing of any change in construction from the previously approved plans and specifications or permit. If the Permit Board determines the changes are substantial, it may require the submission of a new application to construct with "as built" plans and specifications. Notwithstanding any provision herein to the contrary, the acceptance of an "as built" application shall not constitute a waiver of the right to seek compliance penalties pursuant to State Law.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.5.D(2).)

6.2 For the entire facility, the permittee shall submit a stack test protocol at least thirty (30) days prior to the scheduled test date to ensure that all test methods and procedures are acceptable to the MDEQ. If the initial stack test protocol is acceptable, subsequent test protocols may be waived if these protocols contain no significant changes. Also, the MDEQ must be notified at least ten (10) days prior to the scheduled test date so that an observer may be schedules to witness the test(s).

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

6.3 For the entire facility, the permittee shall submit a report of any stack test results within sixty (60) days of conducting the respective stack test.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

6.4 For the entire facility, the permittee shall submit a summary of the 12-month rolling totals for CO, PM($PM/PM_{10}/PM_{2.5}$), VOC, NOx, and H_2SO_4 mist emissions during the semiannual reporting period. For Emission Point AA-001, the report shall also indicate whether there were any periods where the CEMS indicated emissions were in excess of the concentration or lb/hr (24-hour rolling average based on a one-hour average) emission limits. The information above shall be submitted in the semi-annual report required in Condition 6.1(b).

6.9 For Emission Point AA-001, the permittee shall comply with all applicable reporting requirements of 40 CFR 60, Subpart KKKK.

(Ref.: 40 CFR 60.4375(a), 60.4375(b), and 60.4395, Subpart KKKK)

6.10 For Emission Point AA-001, the permittee shall submit the notifications specified in 40 CFR 60.7(a)(1) and (3) and 60.19, as applicable to the affected EGU (see table 3 of Subpart TTTTa).

(Ref.: 40 CFR 60.5550a(a), Subpart TTTTa)

6.11 For Emission Point AA-001, the permittee shall submit notifications specified in 40 CFR 75.61, as applicable, to the affected EGU.

(Ref.: 40 CFR 60.5550a(b), Subpart TTTTa)

6.12 For Emission Point AA-001, the permittee shall and submit reports according to 40 CFR 60.5555a(a) through (d) (Conditions 6.12 through 6.14), as applicable.

(a) For affected EGUs that are required by 40 CFR 60.5525a (Condition 5.15) to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, the permittee shall submit quarterly electronic reports as follows. After accumulating the first 12-operating months for the affected EGU, the permittee shall submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(b) Each quarterly report shall include the following information, as applicable:

(1) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. The permittee shall calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in 40 CFR 60.5540a (Condition 5.16). The permittee shall report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, the permittee must include a statement to that effect;

(2) If one or more compliance periods end in the quarter, the permittee shall identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(3) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, the permittee shall include a statement indicating this in the report;

(i) The date of provisional certification, as defined in 40 CFR 75.19(a)(3); or

(ii) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(2) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(c) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph B, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j) of this chapter, 40 CFR 75.40(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in 40 CFR 60.5540a(a)(1) (Condition 5.16) and shall not be used in the compliance determinations under 40 CFR 60.5540a (Condition 5.16).

(Ref.: 40 CFR 60.5555a(c), Subpart TTTTa)

6.15 For Emission Point AA-001, the reports required under Conditions 6.11 and 6.14(a) shall be submitted by:

(a) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(b) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(c) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(Ref.: 40 CFR 60.5555a(d), Subpart TTTTa)

6.16 For Emission Points AA-005, AA-006, and AA-007, the permittee shall submit semi-annual reports in accordance with Condition 6.1(b) of leaks detected through the AVO monitoring plan as well as all repairs made to the fugitive sources. If no leaks are detected and no repairs are made, the permittee shall instead submit a negative declaration.

(Ref.: 11 Miss. Admin. Code Pt. 2, R. 2.2.B(11).)

SECTION 3

PUBLIC NOTICE AND PROOF OF PUBLICATION

Public Notice
Mississippi Environmental Quality Permit Board
P. O. Box 2261 | Jackson, MS 39225
515 East Amite St. | Jackson, MS 39201
Telephone No. (601) 961-5171

Public Notice Start Date: March 5, 2025 MDEQ Contact: Clinton Gentry

Entergy Mississippi LLC, Delta Blues Advanced Power Station, located at 85 Stokes King Road, in Greenville, MS, (Washington County) has applied to the Mississippi Department of Environmental Quality (MDEQ) for the following permitting action(s): Prevention of Significant Deterioration (PSD) Construction Permit, Air Ref. No. 2800-00142. The applicant's operations fall within SIC Code 4911. A Statement of Basis has been prepared that contains a discussion of the decision-making that went into the development of the permit and provides the permitting authority, the public, and other government bodies a record of the technical issues surrounding issuance of the permit. The Statement of Basis also addresses any changes to emissions and/or discharges resulting from any modification of the facility.

Entergy Mississippi, LLC (Entergy) submitted a PSD Construction application proposing to build a new natural gas-fired 1x1 combined cycle power plant in Greenville, MS which will be referred to as the Delta Blues Advanced Power Station (DBAPS). This plant will be nominally rated to provide 750 megawatts (MW) of net power.

The power generation equipment proposed for DBAPS includes a Mitsubishi Model M501JAC Gas Turbine (GT) equipped with supplementary-fired duct burners and a Heat Recovery Steam Generator (HRSG). In addition to power from a generator turned by the gas turbine shaft, additional power is supplied by a generator turned by a steam turine which is fed steam generated in the HRSG. The proposed facility will have other ancilllary sources of air pollution which include: one diesel-fired emergnecy standby generator, one diesel-fired firewater pump, one natural gas fired heater, natural gas fugitive emisisons, ammonia fugitive emissions, diesel fugitive emissions, combustion turbine lube oil vent emissions, steam turbine lube oil vent emissions, two ultra low sulfur diesel (ULSD) storage tanks for the emergency generator and the fire water pump.

This project has potential emisisons that exceed the PSD thresholds for for Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Volatile Organic Compounds (VOCs), Particulate Matter (PM_{10} and $PM_{2.5}$), Sulfuric Acid Mist (H_2SO_4), and Greenhouse Gasses (GHG). For PM_{10} and NO_X which set certain requirements on the permissible incremental impact on air quality and the degree of control of air contaminants and has been reviewed for compliance with those regulations. The project will be located in a PSD Class II area and the following consumption of air quality increments is predicted to occur:

Particulate Matter Less than 10 microns

Annual	0.1211 micrograms per cubic meter or
	0.71% of the 17 micrograms per cubic meter increment.
24-Hour	1.462 micrograms per cubic meter or
	4.87% of the 30 micrograms per cubic meter increment.

Nitrogen Dioxide

SECTION 4

TRANSMITTAL LETTERS TO EPA AND JURISDICTIONAL BODIES

Clinton Gentry

From:	Clinton Gentry
Sent:	Tuesday, March 4, 2025 7:58 AM
To:	awicks@greenvillems.org
Subject:	Entergy Mississippi LLC Delta Blues Advanced Power Station; Air Permit #2800-000142; Public Notice
Attachments:	2800-00142 Online Draft Permit.pdf

Good Morning,

Attached is the draft Prevention of Significant Deterioration (PSD) air construction permit for the proposed Entergy Mississippi's Delta Blues Advanced Power Station (DBAPS). The permit will enter the public notice draft period from March 5, 2025 and last until April 4, 2025, during which time comments from the public may be submitted to MDEQ for review. Additional information regarding the permit may be found at https://www.mdeq.ms.gov/ensearch/epd-permits-at-public-notice/.

Thanks,

Clinton Gentry, P.E.
Mississippi Department of Environmental Quality
Office of Pollution Control
Environmental Permits Division – Air 1
(601) 961-5145

Clinton Gentry

From: cgentry@mdeq.ms.gov
Sent: Monday, April 21, 2025 4:44 PM
To: Clinton Gentry
Subject: EPA/MDEQ PSD Draft Permit enReview (Entergy Mississippi LLC Delta Blues Advanced Power Station)

This Message Is From an External Sender
This message came from outside your organization.

PSD Notice

The Mississippi Department of Environmental Quality has prepared a draft PSD permit for the facility identified below. A copy of this draft permit and other relevant documents can be viewed using the following link.

Permit No. 2800-00142.

Additional facility information can be viewed at: Entergy Mississippi LLC Delta Blues Advanced Power Station.

A summary of all PSD applications under review in Mississippi can be viewed at: MDEQ PSD enReview.

Facility Name: Entergy Mississippi LLC Delta Blues Advanced Power Station
City: Greenville
County: Washington

Please contact the permit writer, Clinton Gentry ((601) 961-5145 / cgentry@mdeq.ms.gov), or the branch manager, Jeffrey Bland ((601) 961-5112 / JBland@mdeq.ms.gov), for additional information or if any of the associated documents are not available.

Recipients: JBland@mdeq.ms.gov, NSRsubmittals@epa.gov, PBRADLEY@MDEQ.MS.GOV, Shepherd.Lorinda@epa.gov, adams.yolanda@epa.gov, asmith@mdeq.ms.gov, gillam.rick@epa.gov, howard.chris@epa.gov, ipilgrim@mdeq.ms.gov, kmertes@mdeq.ms.gov, rcuevas@mdeq.ms.gov.

This email was electronically generated on Mon 21-Apr-2025 21:44:26 and is intended to complete the notification requirements under 40 CFR 51.166(q)(2)(iv) adopted by reference in Mississippi Commission on Environmental Quality Regulation 11, Mississippi Administrative Code, Part 2, Chapter 5.

Clinton Gentry

From: Musmanno, Kathleen (she/her/hers) <Musmanno.Kathleen@epa.gov>
Sent: Friday, October 11, 2024 12:10 PM
To: Clinton Gentry
Subject: RE: Entergy SPS PSD application

This Message Is From an External Sender
This message came from outside your organization.

Hi Clinton,

I have reviewed the supplemental information and don't have any further comments or concerns.

Thanks,

Kathleen Musmanno
Region 4 EPA
Air Permits Section
404-562-9170
She/her

From: Musmanno, Kathleen (she/her/hers)
Sent: Thursday, October 3, 2024 2:37 PM
To: Clinton Gentry <cgentry@mdeq.ms.gov>
Subject: RE: Entergy SPS PSD application

Hi Clinton,

Thank you for the response! I will review this and get back to you as soon as possible.

Thanks,
Kathleen

From: Clinton Gentry <cgentry@mdeq.ms.gov>
Sent: Thursday, October 3, 2024 11:55 AM
To: Musmanno, Kathleen (she/her/hers) <Musmanno.Kathleen@epa.gov>
Subject: RE: Entergy SPS PSD application

Caution: This email originated from outside EPA, please exercise additional caution when deciding whether to open attachments or click on provided links.

Good Afternoon,

Entergy has provided me with another supplemental BACT analysis addressing your comments and concerns with the previous iteration. Please let me know if these comments are satisfactory to EPA and if you would like additional information submitted for Entergy before their BACT analysis is approved.

After speaking with Entergy, they have provided me the updated BACT analysis as well as more accurate worst case uncontrolled emissions. If you have any questions/concerns with these, please let me know and I'll convey them to Entergy.

Thanks,

Clinton Gentry, P.E.
Mississippi Department of Environmental Quality
Office of Pollution Control
Environmental Permits Division – Air 1
(601) 961-5145

From: Weil, Kathleen (she/her/hers) <Weil.Kathleen@epa.gov>
Sent: Tuesday, July 16, 2024 8:08 AM
To: Clinton Gentry <cgentry@mdeq.ms.gov>
Subject: RE: Entergy SPS PSD application

Thank you!

From: Clinton Gentry <cgentry@mdeq.ms.gov>
Sent: Monday, July 15, 2024 3:51 PM
To: Weil, Kathleen (she/her/hers) <Weil.Kathleen@epa.gov>
Subject: RE: Entergy SPS PSD application

Kathleen,

Thank you for reviewing the application and letting me know the major points that need to be addressed. I plan to discuss your comments with Entergy this week and will ask them for additional information to supplement the current application.

- Regarding the calculations in Section B.1, it is typical for our emergency engines to have a lb/hr emission that does not directly calculate forward to a tpy limit based off 8760. Those are generally given to use with the max non-emergency hours that the engine is allowed to operate on. However, I do plan to ask the facility to either justify or correct their sulfate/pm emissions for SPS-1A. Their tpy emissions are based off an unfamiliar annual average emission factor while their lb/hr emissions are based off a different max hourly emission factor.

- A more thorough top-down elimination BACT analysis is also something that we have discussed internally prior to your comment. We will ask the facility to supplement the current analysis and I will provide that information to you once I have received it.

If you have any other comments/concerns with the application, please let me know and I will discuss them with the facility.

Thanks,

Clinton Gentry, P.E.
Mississippi Department of Environmental Quality

"Delta Blues Advanced Power Station" instead of "Sawgrass Power Station", which isn't reflected in the application yet.

Thanks,

Clinton Gentry, P.E.
Mississippi Department of Environmental Quality
Office of Pollution Control
Environmental Permits Division – Air 1
(601) 961-5145

From: Weil, Kathleen (she/her/hers) <Weil.Kathleen@epa.gov>
Sent: Monday, June 10, 2024 11:50 AM
To: Clinton Gentry <cgentry@mdeq.ms.gov>
Subject: Entergy SPS PSD application

Hi Clinton,

I'm reviewing the Entergy Mississippi Sawgrass Power Station PSD application, and I was wondering if you could share the application's appendix C and D? My copy stops at appendix B.

Thanks,

Kathleen Weil
Region 4 EPA
Air Permits Section
404-562-9170
She/her

SECTION 5

ACKNOWLEDGEMENTS RECEIVED

[No Comments Received]

SECTION 6

RESPONSE TO COMMENTS

[No Comments Received]