

**Pre-Construction Review  
and  
Preliminary Determination  
of Approval for  
Entergy Mississippi LLC, Vicksburg Advanced Power Station  
Facility No. 2780-00027**

**Technical Review  
by  
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By  
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## **I. General Information**

Entergy Mississippi LLC (“Entergy”), Vicksburg Advanced Power Station (“VAPS), located at 770 Kemp Bottom Road Vicksburg, Mississippi 39180, (972) 743-9649 (Jeremy Halland, Environmental Project Services), has submitted a complete air permit application for a Prevention of Significant Deterioration Construction Permit to construct a new natural gas-fired 1x1 combined cycle power plant.

## **II. Project Description**

Entergy’s proposed VAPS will be a new 750-MW natural gas fired 1x1 combined cycle base-load power plant.

### **Gas Turbine, Duct Burner, and Steam Turbine Operations**

The power generation equipment proposed for the VAPS includes a Mitsubishi model M501JAC Gas Turbine (GT) equipped with supplementary-fired duct burners and a Heat Recovery Steam Generator (HRSG). To boost the thermal efficiency of the gas turbine, the combustion air fed to the GT compressor can be saturated with water in an evaporative cooler at various times, predominantly during warm weather conditions. In addition to power from a generator turned by the gas turbine shaft, additional power is produced by a steam turbine generator which is fed steam generated in the HRSG. Final condensation of steam exiting the steam turbine is accomplished using air-cooled condensers. No cooling towers will be present at the VAPS. At the 59° F ISO design case, the VAPS 1x1 combined cycle unit will have an efficient net heat rate of 6,396 Btu/kWh-HHV, which equates to a relatively high net thermal efficiency of 51.8% (HHV basis). The maximum firing rates of the GT and duct burner are 4,120 million (MM) Btu/hr-HHV, and 863 MMBtu/hr-HHV, respectively, at a cold weather ambient temperature firing condition of 10° F. The gas turbine and duct burners will be permitted to operate continuously (8,760 hr/yr). Numerous performance scenarios are presented in Table A-2 in Appendix A of the Prevention of Significant Deterioration Construction Permit Application and associated emissions have been calculated for each operating scenario.

GT and duct burner combustion flue gas exits the main stack after passing through the emission control equipment (Emission Point AA-001). Proposed emission controls for the flue gas out of the main stack include an ammonia-based Selective Catalytic Reduction (SCR) system to reduce NO<sub>x</sub> emissions and a catalytic oxidation unit to reduce CO and VOC emissions. Emissions of GHGs are limited by using natural gas as a fuel and installing a power generation system with high thermal efficiency.

### **Lube Oil Recirculation Systems**

The new combustion turbine and steam turbine will each be equipped with a dedicated lubrication system. Lubrication oil will be circulated through each turbine’s machinery from the system’s 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 emissions are expected to be emitted from the combustion turbine lube oil vent (Emission Point AA-008) and the steam turbine lube oil vent (Emission Point AA-008). 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 5.01 MMBtu/hr natural gas fired dewpoint heater (Emission Point AA-004). 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 the VAPS 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 (VAPS-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 (Emission Point AA-001) 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 VAPS is proposing to have two emergency diesel-fired Internal Combustion (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 brake horsepower (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.

The other emergency diesel-fired IC engine is a 235-kW emergency fire water pump. The proposed engine is a John Deere Model 6068HFC48A with a 282 BHP rating. The engine will only fire ULSD with a maximum sulfur content of 15 ppmw. The engine will be a USEPA-certified Tier 2 engine.

### **Diesel, Natural Gas Condensate, and Ammonia Storage Tanks**

The VAPS is proposing to have two fixed-roof diesel storage tanks. Each tank will provide ULSD fuel to one of the two emergency IC engines. The tank that will supply ULSD to the emergency generator is a 99 barrel (bbl) (4,150 gallon) white, horizontal fixed-roof tank (Emission Point AA-010). The tank will supply ULSD to the emergency fire water pump is a 12 bbl (500gal) white, horizontal fixed-roof tank (Emission Point AA-011).

The VAPS is proposing to have two 400-gallon fixed-roof natural condensate tanks (Emission Points AA-012 and AA-013). These tanks will knock out and collect natural gas condensate to prevent it from entering the GT in rare occurrences when condensate is present in the incoming pipeline natural gas.

Ammonia will be stored in a 40,000-gallon pressurized tank with no routine air emissions. Therefore, no emission point ID is assigned to the ammonia storage tank.

### **Fugitive Emissions**

The proposed site will have piping in natural gas, diesel and ammonia service. Potential fugitive emissions from piping components (valves, flanges, connectors, pumps, open-ended lines, and relief valves) are calculated based on a count of components and emissions factors associated with the liquid or gas/vapor service of the components. Equipment components are either in natural gas, diesel or ammonia service. The fugitive emission sources are defined by their service as follows:

- Emission Point AA-005 – addresses fugitive emissions of equipment components in natural gas service.
- Emission Point AA-006 – addresses fugitive emissions of equipment components in ammonia service.
- Emission Point AA-007 - addresses fugitive emissions of equipment components in diesel service.

## **III. Federal Regulations**

#### **40 CFR 60, Subpart III – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**

This subpart establishes standards and compliance schedules for manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE). Emission Points AA-002 and AA-003 meet the definition of new, stationary RICE. As such, these emission points are subject to this subpart.

#### **40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines**

This subpart establishes standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005. 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 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 III 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**

<b>Pollutant</b>	<b>Project-Related Increases (TPY)</b>	<b>Significant Emission Rate (TPY)</b>	<b>Netting Analysis Required? (Yes/No)</b>	<b>Contemporaneous Emissions (TPY)</b>	<b>Total Net Emissions (TPY)</b>	<b>PSD Review Required? (Yes/No)</b>
PM	124.40	25	No	0.00	124.40	Yes
PM <sub>10</sub>	166.59	15 <sup>1</sup>	No	0.00	166.59	Yes
PM <sub>2.5</sub>	166.59	10	No	0.00	166.59	Yes
NO <sub>x</sub> <sup>1,2</sup>	222.84	40	No	0.00	222.84	Yes
SO <sub>2</sub> <sup>1</sup>	30.37	40	No	0.00	30.37	No
VOC <sup>2</sup>	403.83	40	No	0.00	403.83	Yes
CO	1198.32	100	No	0.00	1198.32	Yes

<sup>1</sup> As of April 28, 2011, both NO<sub>x</sub> and SO<sub>2</sub> are precursors for PM<sub>2.5</sub>. Therefore, if NO<sub>x</sub> or SO<sub>2</sub> exceed 40 TPY, the project is considered major for PM<sub>2.5</sub>.

<sup>2</sup> Both NO<sub>x</sub> and VOC are considered precursors for ozone with a significant emission rate of 40 TPY each.

In accordance with PSD requirements listed in 40 CFR 51.166(j) and 52.21(j) and 11 Miss. Admin. Code Pt. 2, Ch. 5. Rule 5.1, a new major stationary source must apply BACT for the control of each regulated air pollutant emitted in significant quantities. Therefore, Entergy completed a BACT analysis for VOC, PM, NO<sub>x</sub>, and CO.

BACT is defined in the federal PSD regulation at 40 CFR 52.21(b)(12) as follows:

Best available control technology (BACT) means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR 60, 61, or 63. If the administrator determines the technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be

prescribed instead to satisfy the requirement for the application of best available control technology. Such standards shall, to the degree possible, set for the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The selection of BACT requires consideration of cost, environmental, and energy impacts. In the USEPA's draft document New Source Review Workshop Manual (USEPA, October 1990), USEPA recommends a "top-down" approach when evaluating commercially available and demonstrated air pollution control technologies for BACT. Note that a top-down approach is suggested by policy and not by regulation. For certain small emission sources, the BACT demonstration may depend on what is typically used in industrial applications as detailed in the RBLC information in Appendix C. According to the definition of BACT, if a facility is subject to a NSPS or NESHAP standard, the selected BACT must never result in an emission limit that is less stringent than any applicable NSPS and/or NESHAP rule.

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 VAPS. The following sections describe the pollutant-by-pollutant BACT for all emissions units at the proposed VAPS facility.

### ***A. Gas Turbine/Duct Burner Combustion Main Stack (Emission Point AA-001)***

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 Emission Point AA-001.

#### ***(1) Nitrogen Oxides (NO<sub>x</sub>) BACT Analysis***

NO<sub>x</sub> is generally formed during combustion by thermal oxidation of nitrogen in the combustion air (thermal NO<sub>x</sub>) and the oxidation of nitrogen in the fuel (fuel-bound NO<sub>x</sub>). Natural gas contains relatively small amounts of fuel-bound nitrogen and NO<sub>x</sub> formation through the fuel NO<sub>x</sub> mechanism is expected to be insignificant. The main variables affecting NO<sub>x</sub> 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. NO<sub>x</sub> 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. Advanced combustor design also includes reducing the combustion zone residence time and limiting the oxygen available to combine with nitrogen to form NOx. Entergy's proposed gas turbine and duct burner include DLN combustors. This technology can achieve a flue gas NOx concentration between 9 and 25 ppmvd @ 15% O2.
- **Selective Catalytic Reduction (SCR):** SCR is similar to SNCR except that with SCR, a catalyst is present during the chemical reactions that produce nitrogen and water vapor from NOx. Like SNCR, SCR requires ammonia injection to participate in the NOx reduction chemical reactions. Entergy proposes utilizing SCR for this gas turbine/duct burner installation. By itself, this technology can achieve a flue gas NOx concentration between 2 and 3 ppmvd @ 15% O2. In conjunction with DLN burners, this technology can achieve a flue gas NOx concentration of 2 ppmvd @ 15% O2.
- **Selective Non-Catalytic Reduction (SNCR):** SNCR is a process in which ammonia or urea is injected directly into the exhaust gas stream to produce nitrogen and water vapor from NOx. The chemical reactions take place without the presence of a catalyst, and due to reaction temperature considerations, the ammonia or urea injection must occur in a location where the exhaust gas temperatures are between approximately 1,600°F and 2,000°F. The exhaust gas temperature range for the proposed units does not allow SNCR to be a feasible control technology, as the exhaust temperature for this project will be considerably below this range.
- **Non-Selective Catalytic Reduction (NSCR):** NSCR is a process that utilizes a catalyst to produce nitrogen and water vapor from NOx without the presence of a reducing agent. This technology has not yet been developed for large-scale combustion turbine applications and is currently only utilized in reciprocating internal combustion engines. Thus, NSCR is considered technically infeasible for this application.

**Step 2: Eliminate Technically Infeasible Options**

Two available NOx control technologies were determined not to be technically feasible. As described above, these technically infeasible NOx control technologies include SNCR and NSCR.

**Step 3: Rank Remaining Options by Control Effectiveness**

The available and technically feasible NOx control technologies for gas turbine/duct burner installations are ranked in order in Table 7.1.

**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**

Entergy proposes to accept the top control technology in Table 1.1. 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.

<b>Table 1.1: GT/DB NOx Technically Feasible Control Options</b>		
<b>Ranking</b>	<b>GT/DB NOx Control Technology</b>	<b>NOx Concentration (PPMVD @ 15% O2)</b>
1	SCR + Dry Low NOx Combustors/Burners	2.0
2	SCR	2 – 3
3	Dry Low NOx Combustors/Burners	9 – 25
4	Water/Steam Injection	42

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

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 NO<sub>x</sub> 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 effective at limiting CO formation by maintaining the optimum combustion zone temperature and amount of excess oxygen. Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of CO emissions may lead to increased NO<sub>x</sub> emissions. Consequently, typical practice is to design the combustion system such that CO emissions are reduced as much as possible without causing NO<sub>x</sub> levels to significantly increase.

The only add-on control device that is commercially available for controlling CO emissions from gas turbine/duct burner installations is an oxidation catalyst. The catalyst lowers the activation energy necessary for CO to react with available oxygen in the exhaust to produce CO<sub>2</sub>. Oxidation catalysts operate optimally at a temperature range of 500° to 700° F and can also reduce volatile organic compounds (VOC) emissions.

### **Step 2: Eliminate Technically Infeasible Options**

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

### **Step 3: Rank Remaining Options by Control Effectiveness**

The top CO 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 CO concentration of 2.0 ppmvd CO @ 15% O<sub>2</sub> (24-hr-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 CO control technology.

### **Step 5: Select BACT**

The GT/duct burner system will utilize good combustion techniques and an add-on catalytic oxidation control system. This will yield a vendor-guaranteed flue gas CO concentration of 2.0 ppmvd CO @ 15% O<sub>2</sub> (24-hr-average basis). Based on a review of RBLC, this control system represents the “top” available and feasible CO control technology for GT/duct burner systems. There were 108 RBLC entries with a primary CO limit ranging up to 50 ppmvd with the majority of limits set at 2.0 ppmvd. As a result, catalytic oxidation with a CO performance level of 2.0 ppmvd CO @ 15% O<sub>2</sub> (24-hr-average basis) is selected as BACT for CO.

### **(3) Volatile Organic Compounds (VOC) BACT Analysis**

Like CO, VOC emissions result from incomplete combustion. VOC is unburned and emitted from the stack when there is a lack of oxygen and insufficient residence time at high enough temperatures to complete the final step in oxidation.

#### **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% O<sub>2</sub> (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% O<sub>2</sub> (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% O<sub>2</sub> (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<sub>10</sub> and PM<sub>2.5</sub>) BACT Analysis**

Particulate matter (PM) emissions, which include both PM<sub>10</sub> and PM<sub>2.5</sub> 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**

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

- Fabric Filter (Baghouse);
- Electrostatic Precipitator (ESP);
- Use of Clean Gaseous Fuels (e.g., pipeline quality natural gas); and
- Good Combustion Practices.

**Step 2: Eliminate Technically Infeasible Options**

The two available add-on PM control technologies identified above, baghouses and ESPs, were determined not to be technically feasible. The concentration of PM in the flue gas from a gas turbine/duct burner installation is low. Further, the sizes of particles in the flue gas stream are very small. Due to the high volumetric flow rates and low particulate concentrations in the exhaust stream from the gas turbine/duct burner installation, use of a baghouse or ESP is considered technically infeasible and are eliminated from further BACT consideration. There are no known existing natural gas fired gas turbine/duct burner installations that utilize add-on PM control equipment.

**Step 3: Rank Remaining Options by Control Effectiveness**

The use of good combustion practices and clean gaseous fuels are both technically feasible options, and the use of both options is what is selected for BACT for this installation.

**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**

By virtue of firing clean-burning pipeline natural gas PM10 and PM2.5 are emitted in small quantities from the GT/duct burner. The use of a catalytic oxidation system results in additional PM emissions, but this tradeoff is acceptable to further control emissions of VOC and CO. The expected flue gas PM concentration exiting the stack will still be very dilute. The selected PM BACT is the use of low sulfur pipeline natural gas and good combustion practices such that PM emissions will be limited to 0.0095 lb PM/MMBtu (annual-average basis). Good combustion practices include proper GT/duct burner design, performing recommended maintenance, and proper operation of the system to promote efficient combustion.

**(5) Sulfuric Acid Mist (SAM) BACT Analysis**

Emissions of SO<sub>2</sub> occur from the oxidation of sulfur in the gaseous fuel fired in the GT/duct burner system. Most fuel sulfur is converted to SO<sub>2</sub>. A portion of the SO<sub>2</sub> will be further converted to H<sub>2</sub>SO<sub>4</sub>, also referred to as (SAM), which will exit from the main stack.

**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 SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub> 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 CO<sub>2</sub>, methane (CH<sub>4</sub>) and nitrous oxide (N<sub>2</sub>O). The primary GHG is CO<sub>2</sub>, and the combined GHGs are expressed as CO<sub>2</sub> equivalents (CO<sub>2</sub>e) 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 CO<sub>2</sub> emissions and not any other GHG constituents. EPA's reason for phasing in GHG limits for this source category was that some of the necessary GHG control technologies are not currently commercially available. For Entergy's proposed new base load GT/duct burner facility, the applicable phased-in CO<sub>2</sub> emission limits from Table 1 of NSPS TTTTa include:

- From the start of operation until December 31, 2031, a CO<sub>2</sub> emissions performance level of less than 800 lb CO<sub>2</sub>/MWh gross energy output (12-operating month average).
- For all operations after December 31, 2032, a CO<sub>2</sub> emissions performance level of less than 100 lb CO<sub>2</sub>/MWh of gross energy output (12-operating month average).

In developing NSPS TTTTa, EPA recognized that the infrastructure to support Carbon Capture Sequestration (CCS) is not currently available in all geographical areas. For this reason, in the preamble to the NSPS TTTTa rule in the May 9, 2024 *Federal Register*, EPA described its plan to structure NSPS TTTTa to have two phased in GHG control stages for base load combined cycle power plants:

“The BSER for base load combustion turbines includes two components to be implemented initially in two phases. The first component of the BSER for base load combustion turbines is highly efficient generation (based on the emission rates that the best performing units are achieving) and the second component for base load combustion turbines is utilization of CCS with 90 percent capture. Recognizing the lead time that is necessary for new base load combustion turbines to plan for and install the second component of the BSER (*i.e.*, 90 percent CCS), **including the time that is needed to deploy the associated infrastructure (CO<sub>2</sub> pipelines, storage sites, [emphasis added] *etc*)**, the EPA is finalizing a second phase compliance deadline of January 1, 2032, for this second component of the standard.”

**Step 1: Identify Available Control Technologies**

The available control technologies to lower GHG emissions from GT/duct burner installations include:

- Carbon Capture and Sequestration (CCS);
- Combustion of fuel containing hydrogen; and
- Operating a system that has a high thermal efficiency with relatively low-carbon natural gas fuel.

Research has been performed by the U.S. Department of Energy and others to limit GHG emissions from combined cycle units by employing CCS. In a CCS system, CO<sub>2</sub> emissions are captured, scrubbed, condensed, and routed via pipeline to an underground formation where the CO<sub>2</sub> is stored indefinitely (sequestered). Once the CO<sub>2</sub> is separated from the flue gases, it must be transported to a suitable sequestration or storage facility. Storage opportunities typically would include disposing of the CO<sub>2</sub> in a Class 2 well used for enhanced oil recovery or disposing of the CO<sub>2</sub> in a Class 6 well which is used to inject CO<sub>2</sub> into deep rock formations, as part of a process called Geologic Sequestration. Using CO<sub>2</sub> for Enhanced Oil Recovery is unstable because the demand for the CO<sub>2</sub> fluctuates significantly depending on the price of oil and natural gas. Therefore, it is not a reliable means of disposing of CO<sub>2</sub>.

There has been discussion over whether CCS technology is currently commercially available for CO<sub>2</sub> emissions control in all geographic regions. In some specific geographic locations, the technology and infrastructure to support CCS is present for combined cycle power plants; however, this is not the case for the proposed VAPS. For a top-down BACT demonstration, as presented below, the first step is to evaluate whether a specific control technology is “available”. In USEPA’s 1990 New Source Review Workshop Manual on page B.5, USEPA states that “available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.” The determination of BACT “availability” must be made for a specific emissions unit in a specific geographic location. In the GHG BACT demonstration for the proposed VAPS combined cycle combustion turbine emissions unit, EML contends that the proposed site currently lacks the required infrastructure to make CCS a viable control technology option in the near future. For example, there is no CO<sub>2</sub> pipeline near the proposed VAPS site and, to date, there are no Class 6 carbon sequestration wells permitted in the state of Mississippi. Therefore, this means CCS is not “available” at the current time for the VAPS based on USEPA’s description of “available” BACT.

The VAPS combined cycle system is being designed such that a CCS retrofit could be accommodated in the future. For these reasons, CCS is rejected as GHG BACT for this installation. Entergy will consider CCS when planning for operation of the facility to meet the NSPS TTTT a CO<sub>2</sub> emission limit that becomes effective on January 1, 2032.

The use of hydrogen as a fuel reduces CO<sub>2</sub> emissions because the product of hydrogen combustion is water. Studies by GT manufacturers indicate that with current GT technology, the quantity of hydrogen fuel a GT can accommodate is approximately 30%. The remaining balance of the fuel fired must be natural gas. At the time the proposed GT/duct burner installation 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 CO<sub>2</sub> emission limit that becomes effective on January 1, 2032.

GT based combined cycle power plants fired with natural gas fuel represent the most thermally efficient fossil fuel fired EGUs available in the commercial marketplace. The proposed VAPS combined cycle unit represents state-of-the art equipment in terms of thermal efficiency. This high level of thermal efficiency is achieved by employing a highly efficient GT, a highly efficient duct burner system, and a highly efficient HRSG, all deployed in a highly efficient combined cycle configuration. Combined-cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. The combustion turbine operates on the Brayton cycle, while the HRSG and steam turbine operate on the Rankine cycle. Combining the two thermodynamic cycles into a single-power generation system results in the high thermal efficiency associated with combined cycle power plants.

The most thermodynamically efficient way to generate electricity from a natural gas fuel source is by employing a combined cycle design. For commercially available fossil fuel fired EGU technologies, the expected net thermal efficiency ranges from approximately 30 to 50% (HHV). A typical coal-fired Rankine cycle power plant has a base load net thermal efficiency of approximately 30% (HHV) at ISO conditions, while a modern natural gas-fired combined cycle unit has a base load net thermal efficiency at ISO conditions of approximately 50% (HHV). The VAPS combined cycle system exceeds these benchmarks. At the 59°F ISO design case, the VAPS combined cycle unit will have a net thermal efficiency of 51.82% (HHV). This thermal efficiency may degrade slightly over the life of the unit, but periodic maintenance will be performed to bring the unit back to optimal efficiency. The thermal efficiency will remain high enough that the VAPS EGU continuously complies with the NSPS TTTTa first-phase GHG control limit of less than or equal to 800 pounds CO<sub>2</sub>/MWh of gross energy output (12-operating-month average basis).

In addition to the high-efficiency primary components of the combustion turbine, there are several other design features employed that improve the thermal efficiency of the VAPS combined cycle EGU. These design elements include, but are not limited to, employing insulation to prevent heat loss, use of an evaporative cooler to saturate combustion air with water, and use of a blowdown heat recovery system.

Modern combustion turbines like the Mitsubishi M501JAC model have regularly scheduled maintenance programs. These maintenance programs are important to ensure reliable operation of the unit and to maintain optimal thermal efficiency. As the combustion turbine is operated, the unit experiences degradation and minor losses in thermal performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as (1) combustion inspections, (2) hot gas path inspections, and (3) major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore efficiency to the combustion turbines. Other routine maintenance practices that ensure a high thermal efficiency is continuously achieved include, but are not limited to, minimizing steam leaks, minimizing air filtration, and periodic cleaning and maintenance of heat transfer surfaces.

Modern combustion turbines like the Mitsubishi M501JAC model have sophisticated instrumentation and controls to automatically control the operation of the combined cycle EGU. The digital-type control system is supplied with the combustion turbine. The distributed control system controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve thermally efficient operation. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal thermal performance for full-load and partial-load conditions. The control system thereby enhances thermal efficiency and minimizes emissions of GHGs at all load conditions.

#### **Step 2: Eliminate Technically Infeasible Options**

All of the control options identified in Step 1 are technically feasible; however, at the time of this application, CCS and hydrogen combustion are not currently available GHG control options because of infrastructure limitations (see Step 1). These options may be available by the 2032 timeframe and will be re-evaluated later as required by NSPS Subpart TTTT. The only remaining GHG control option at this juncture is 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**

Entergy is electing to implement the top available technology after eliminating unavailable and technically infeasible options. The remaining option, which is selected as GHG BACT, 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**

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

### **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 CO<sub>2</sub>/MWh gross power output is established by 40 CFR 60 Subpart TTTT<sub>a</sub>. This NSPS TTTT<sub>a</sub> CO<sub>2</sub> 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 CO<sub>2</sub>e/MWh of gross power output.

### ***B. Diesel-fired Emergency Internal Combustion Engines (Emission Points AA-002 and AA-003)***

The VAPS proposes to 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. One emergency diesel-fired IC engine powers a 2,180-kW emergency standby generator (Emission Point AA-002). The engine is a Mitsubishi Model S16R-Y2PTAW2-1 with a 2,923 BHP rating. The other emergency diesel-fired IC engine powers a 235-kW emergency fire water pump (Emission Point AA-003). The engine is a John Deere Model 6068HFC48A with a 282 BHP rating. As required by regulation, the engines will only fire ULSD with a maximum sulfur content of 15 ppmw. The emergency standby generator is a USEPA-certified Tier 2 engine, and the emergency fire water pump is a USEPA-certified Tier 3 engine. Both are approved by regulation for emergency service operations.

#### ***(1) Nitrogen Oxides (NO<sub>x</sub>) BACT Analysis***

##### **Step 1: Identify Available Control Technologies**

The control technologies that are available for emergency diesel-fired IC engines include:

- Selective Catalytic Reduction (SCR);
- Selective Non-Catalytic Reduction (SNCR); and
- Use of an IC engine that is certified to meet the applicable NO<sub>x</sub> emission limits in 40 CFR 60 Subpart IIII, the NSPS for Compression Ignition IC engines (NSPS IIII).

##### **Step 2: Eliminate Technically Infeasible Options**

Add-on NO<sub>x</sub> controls, such as SCR and/or SNCR systems are not technically feasible for emergency engines. Because of the infrequent operation, it is very difficult operate add-on NO<sub>x</sub>

control systems for short periods of emergency operation. Total annual NO<sub>x</sub> emissions from the two engines combined are very small and can be found in Tables A-8 and A-9 in Appendix A. Because of this, add-on NO<sub>x</sub> controls are rejected as NO<sub>x</sub> for the two emergency engines.

**Step 3: Rank Remaining Options by Control Effectiveness**

The only available and technically feasible NO<sub>x</sub> control technology is use of an IC engine that is certified to comply with the applicable NO<sub>x</sub> emission limits in NSPS IIII. This becomes the top option.

**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 NO<sub>x</sub> BACT for the emergency engines is a Tier 2 or Tier 3 engine NO<sub>x</sub> performance level specified in NSPS IIII. This corresponds to the NO<sub>x</sub> 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 NO<sub>x</sub> requirements for engines that maintain an emergency classification. For the diesel-fired Emergency Standby Generator, NO<sub>x</sub> BACT is proposed as the Tier 2 NO<sub>x</sub> performance level of 6.40 g NO<sub>x</sub>/kWh for engines of this power rating. For the diesel-fired Emergency Fire Water Pump (DBAPS-FWP) NO<sub>x</sub> BACT is proposed as the Tier 3 NO<sub>x</sub> performance level of 4.0 g NO<sub>x</sub>/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 that maintain an emergency classification. For the diesel-fired Emergency Standby Generator (Emission Point AA-002), CO BACT is proposed as the Tier 2 CO performance level of 3.5 g CO/kWh for engines of this power rating. For the diesel-fired Emergency Fire Water Pump (Emission Point AA-003), CO BACT is proposed as the Tier 3 CO performance level of 3.5 g CO/kWh for engines of this power rating.

### **(3) Volatile Organic Compounds (VOC) BACT Analysis**

#### **Step 1: Identify Available Control Technologies**

The VOC control technologies that are available include:

- Catalytic oxidation of VOC and
- Good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII VOC 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 VOC 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 VOC for this application is economically prohibitive. Total annual VOC 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 VOC emissions using a catalytic oxidizer exceeds \$100,000 per ton of VOC controlled. For this reason, catalytic oxidation is rejected as BACT for VOC.

**Step 5: Select BACT**

The proposed VOC BACT for the emergency engines is the use of Tier 2 or Tier 3-compliant engines with manufacturer guaranteed performance levels which are more stringent than the NSPS Subpart IIII requirements. Both engines will be subject to and will comply with all applicable NSPS Subpart IIII requirements for engines that maintain an emergency classification. For the diesel-fired Emergency Standby Generator (VAPS-EMGEN), VOC BACT is proposed as the manufacturer's guaranteed VOC performance level of 0.56 g VOC/kWh. For the diesel-fired Emergency Fire Water Pump (VAPS-FWP), VOC BACT is proposed as the manufacturer's VOC performance level of 0.11 g VOC/kWh.

**(4) Particulate Matter (PM<sub>10</sub> and PM<sub>2.5</sub>) 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 (VAPS-EMGEN), PM BACT is proposed as the Tier 2 PM performance level of 0.20 g PM/kWh for engines of this power rating. For the diesel-fired Emergency Fire Water Pump (VAPS-FWP) PM BACT is proposed as the Tier 3 PM performance level of 0.20 g PM/kWh for engines of this power rating.

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

**Step 1: Identify Available Control Technologies**

The GHG control technologies considered this case include:

- Carbon Capture and Sequestration (CCS) and
- Good combustion practices and the use of engines that are certified to meet NSPS IIII emission limits, and the complying with NSPS IIII work practice requirements.

There are no known CCS applications commercially available for emergency diesel-fired IC engines. Therefore, CCS is rejected as BACT.

**Step 2: Eliminate Technically Infeasible Options**

The use of CCS is neither available nor technically feasible. This leaves the only remaining option, which is employing good combustion practices and using engines that are certified to meet NSPS IIII emission requirements.

**Step 3: Rank Remaining Options by Control Effectiveness**

The only remaining option is the top technically feasible technology. This requires employing good combustion practices and the use of engines that are certified to meet NSPS IIII emission requirements.

**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**

Total GHG emissions for these two engines is calculated in Table A-25 of Appendix A. The proposed GHG BACT for both engines is the use of efficient NSPS IIII-compliant USEPA-certified Tier 2 and Tier 3 engines with a GHG emissions performance levels specified in Tables

C-1 and C-2 of 40 CFR Part 98, the mandatory GHG reporting rule as shown in Table A-25 of Appendix A of the PSD application.

### ***C. Natural Gas Dewpoint Heater***

To prevent liquid water droplets from entering the GT and to enhance thermal efficiency, the natural gas fuel to the GT is indirectly heated in a small natural gas-fired dewpoint heater (VAPS-NGDPHTR) that has a rated firing rate of 5.01 MMBtu/hr-HHV. The dewpoint heater will be permitted to operate continuously (8,760 hr/yr).

#### ***(1) Nitrogen Oxides (NO<sub>x</sub>) BACT Analysis***

##### **Step 1: Identify Available Control Technologies**

The NO<sub>x</sub> control technologies that are available for this small gas-fired heater include:

- Selective Catalytic Reduction (SCR);
- Selective Non-Catalytic Reduction (SNCR); and
- Use of Ultra-Low NO<sub>x</sub> Burners

##### **Step 2: Eliminate Technically Infeasible Options**

The use of add-on NO<sub>x</sub> 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 NO<sub>x</sub> controls for this application is therefore rejected as BACT.

##### **Step 3: Rank Remaining Options by Control Effectiveness**

The only available and technically feasible NO<sub>x</sub> control technology for this heater is the use of ULNBs with a manufacturer's guaranteed NO<sub>x</sub> performance level of 0.011 lb NO<sub>x</sub>/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**

NO<sub>x</sub> emissions from this small heater can be found in Table A-10 of Appendix A of the PSD application. NO<sub>x</sub> BACT for this heater is proposed to be the use of ultra-low NO<sub>x</sub> burner technology with a manufacturer's guaranteed NO<sub>x</sub> performance level of 0.011 lb NO<sub>x</sub>/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**

The only available and technically feasible CO control technology remaining for this heater is employing good combustion techniques with a manufacturer's guaranteed burner CO performance level of 0.037 lb CO/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**

CO emissions from this small heater can be found in Table A-10 of Appendix A of the PSD application. CO BACT for this heater is proposed to be the use of good combustion practices to achieve a manufacturer's guaranteed CO performance level of 0.037 lb CO/MMBtu.

## **(3) Volatile Organic Compounds (VOC) BACT Analysis**

### **Step 1: Identify Available Control Technologies**

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

- Oxidation catalysts; and
- Employing good combustion techniques with a manufacturer's guaranteed VOC performance level.

### **Step 2: Eliminate Technically Infeasible Options**

The use of add-on VOC controls such as an Oxidation Catalyst Unit is not technically feasible for this small heater. The use of add-on VOC controls for this application is therefore rejected as BACT.

### **Step 3: Rank Remaining Options by Control Effectiveness**

The only available and technically feasible VOC control technology remaining for this heater is employing good combustion techniques with a manufacturer's guaranteed burner VOC performance level of 0.008 lb VOC/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**

VOC emissions from this small heater can be found in Table A-10 of Appendix A of the PSD application. The use of add-on VOC controls such as an oxidation catalyst system is not technically feasible for this small heater. VOC BACT for this heater is proposed to be the use of good combustion practices to achieve a manufacturer's guaranteed VOC performance level of 0.008 lb VOC/MMBtu.

## **(4) Particulate Matter (PM<sub>10</sub> and PM<sub>2.5</sub>) BACT Analysis**

### **Step 1: Identify Available Control Technologies**

The control technologies that can potentially be used to control PM<sub>10</sub>/PM<sub>2.5</sub> (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
- Good combustion practices use a thermally efficient heater that is fired by relatively low-carbon emitting natural gas fuel.

There are no known CCS applications commercially available for small natural gas-fired heaters. Therefore, CCS is rejected as BACT for this application.

**Step 2: Eliminate Technically Infeasible Options**

The use of CCS is neither available nor technically feasible for this application. This leaves the only remaining option, which is employing good combustion practices with a thermally efficient heater that is fired by relatively low-carbon emitting natural gas fuel.

**Step 3: Rank Remaining Options by Control Effectiveness**

The only remaining option is the top technology for this application. This requires employing good combustion practices with a thermally efficient heater that is fired by relatively low-carbon emitting 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 technically feasible top control technology.

**Step 5: Select BACT**

Total GHG emissions for this small heater can be found in Table A-23 of Appendix A. It is not technically feasible to use CCS technology in this application. The proposed GHG BACT for this small heater is the use of clean burning and efficient pipeline natural gas fuel and the employment of good combustion practices with GHG emissions performance levels specified in Tables C-1 and C-2 of 40 CFR 98, the mandatory GHG reporting rule (see Table A-23 of Appendix A).

#### ***D. Storage Tanks (Emission Points AA-010 through AA-013)***

The DBAPS proposes to have two horizontal fixed-roof diesel storage tanks. Each tank is dedicated to providing ULSD fuel to the two emergency IC engines. The tank that will supply ULSD to the emergency generator will be a 99 bbl (4,150 gal) white, horizontal fixed-roof tank. The tank that will supply ULSD to the emergency fire water pump will be a 12 bbl (500 gal) white, horizontal fixed-roof tank.

##### ***(1) Volatile Organic Compounds (VOC) BACT Analysis***

###### **Step 1: Identify Available Control Technologies**

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

- Use of pressurized storage tanks;
- Use of an internal floating roof tank;
- 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 (Emission Points AA-008 and AA-009)***

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 (Emission Point AA-008) and the steam turbine lube oil vent (Emission Point AA-009) The lube oil vent will be permitted to operate continuously (8,760 hr/yr).

##### ***(1) Volatile Organic Compounds (VOC) BACT Analysis***

###### **Step 1: Identify Available Control Technologies**

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

- Atmospheric vent with a built-in mist eliminator and
- Atmospheric vent with no controls.

###### **Step 2: Eliminate Technically Infeasible Options**

Both options identified above are technically feasible.

###### **Step 3: Rank Remaining Options by Control Effectiveness**

The vent with a built-in mist eliminator represents the highest level of control. This becomes the top option.

###### **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 combined VOC emissions from both lube oil vents can be found in Table A-15 in Appendix A of the PSD application. Use of a mist eliminator is the only feasible VOC control technology for these small VOC sources. Therefore, use of a mist eliminator is proposed as VOC BACT for the two lube oil vents

##### ***(2) Particulate Matter (PM<sub>10</sub> and PM<sub>2.5</sub>) BACT Analysis***

### **Step 1: Identify Available Control Technologies**

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

- Atmospheric vent with a built-in mist eliminator and
- Atmospheric vent with no controls.

### **Step 2: Eliminate Technically Infeasible Options**

Both options identified above are technically feasible.

### **Step 3: Rank Remaining Options by Control Effectiveness**

The vent with a built-in mist eliminator represents the highest level of control. This becomes the top option.

### **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 combined PM emissions from both lube oil vents can be found in Table A-15 in Appendix A of the PSD application. 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 (Emission Points AA-005 through AA-007)***

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 Emission Point AA-005 represents 0.01% of the facility-wide GHG annual emission rate. The GHG emissions for Emission Point 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-005 and AA-007). If an LDAR program were implemented at VAPS, it would monitor both VOC and GHG (methane) emissions.

**(1) Volatile Organic Compounds (VOC) BACT Analysis**

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

Implementing a traditional LDAR program using a portable hydrocarbon detector is technically feasible, but for the minor amount of VOC control offered by an LDAR program, the VOC emission reduction achieved would be cost prohibitive. As shown in the BACT cost estimates in Appendix D of the PSD application, the cost for implementing a sitewide VOC LDAR program with a portable hydrocarbon detector would result in a control cost of over \$30,000/ton VOC emissions reduced. For this reason, implementing an LDAR program is rejected as VOC BACT. The use of an AVO LDAR program becomes the top available option.

**Step 5: Select BACT**

Most fugitive VOC is emitted from natural gas components (Emission Point AA-005). 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 VOC BACT.

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

**Step 1: Identify Available Control Technologies**

The primary GHG fugitive pollutant will be methane from equipment in natural gas service. The available methane control technologies for fugitive methane 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 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts**

An LDAR program that uses a portable hydrocarbon detector is technically feasible, but for the minor amount of GHG control offered by this LDAR program, the GHG emission reduction achieved would be cost prohibitive. As shown in the BACT cost estimates in Appendix D, the cost for implementing a sitewide GHG LDAR program would result in a control cost of over \$578/ton CO<sub>2</sub>e emissions reduced. For this reason, implementing an LDAR program is rejected as GHG BACT. The use of an AVO LDAR program becomes the top available option.

### **Step 5: Select BACT**

Most fugitive methane is emitted from natural gas components (Emission Point AA-005). 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.

## **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 (NAAQS) in any air quality control region or 2) any applicable maximum allowable increase over the baseline concentration, or increment, in any area.

This demonstration is often accomplished by conducting air dispersion modeling. The modeled concentrations used to determine compliance with any NAAQS or 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<sub>2</sub>), the highest, second-highest short-term estimate and the highest annual estimate; and
- For statistically based standards (e.g., PM<sub>10</sub>), the highest, sixth-highest estimate and highest 5-year average estimate.

**A. Existing Air Quality**

Any application for a permit under the Prevention of Significant Deterioration program is required to contain an analysis of ambient air quality in the area that the major stationary source or major modification would affect for each of the following pollutants: a) for the source, each pollutant that it would have the potential to emit in a significant amount; b) for the modification, each pollutant for which it would result in a significant net emissions increase.

The existing ambient air quality is defined by the natural and human-generated sources of air pollution. The area surrounding the Warren County facility is considered rural and in attainment for all regulated pollutants. The pollutants that result in a significant net emission increase as a result of the proposed project and under consideration in this analysis are NO<sub>x</sub>, CO, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, volatile organic compounds (VOCs), H<sub>2</sub>SO<sub>4</sub>. VOCs and nitrogen oxides (NO<sub>x</sub>) combine in the atmosphere to form ozone and, therefore, are called precursor emissions. Any significant emissions increase from an emission unit or net emissions increase at a major stationary source that is significant for VOC or NO<sub>x</sub>, which are precursor pollutants for ozone shall be considered significant for ozone (O<sub>3</sub>). Under current guidance if one precursor for a pollutant exceeds the threshold, then all precursors for that pollutant must be taken into consideration and used in calculations.

**TABLE 2-1 PSD SIGNIFICANCE SUMMARY**

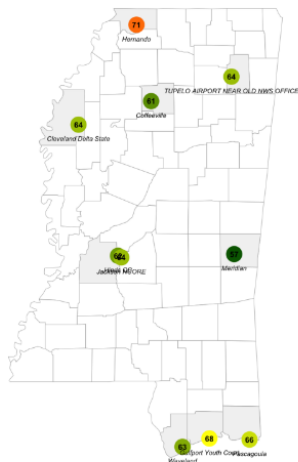
AIR CONTAMINANT	TRIGGERS PSD REVIEW
Nitrogen oxides (NO <sub>x</sub> , as NO <sub>2</sub> and as an ozone precursor))	Yes
Carbon monoxide (CO)	Yes
Sulfur dioxide (SO <sub>2</sub> )	No
Particulate matter (PM)	Yes
PM with a diameter of less than 10 microns (PM <sub>10</sub> )	Yes
PM with a diameter of less than 2.5 microns (PM <sub>2.5</sub> )	Yes
Volatile organic compounds (VOC) (as an ozone precursor)	Yes
Sulfuric Acid Mist (H <sub>2</sub> SO <sub>4</sub> )	Yes

## Primary and Secondary 8-Hour Standard- 70 ppb

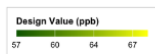
The 8-hour standard is met when the 3-year average of the annual fourth highest daily maximum 8-hour average concentration (also known as the design value) is less than or equal to 0.070 parts per million (ppm) or 70 parts per billion (ppb).

### Mississippi Ozone Monitoring Network (2024)

**Mississippi Ozone Design Values (2024)**  
8-hour average concentration (parts per billion) • EPA Standard: 70 ppb



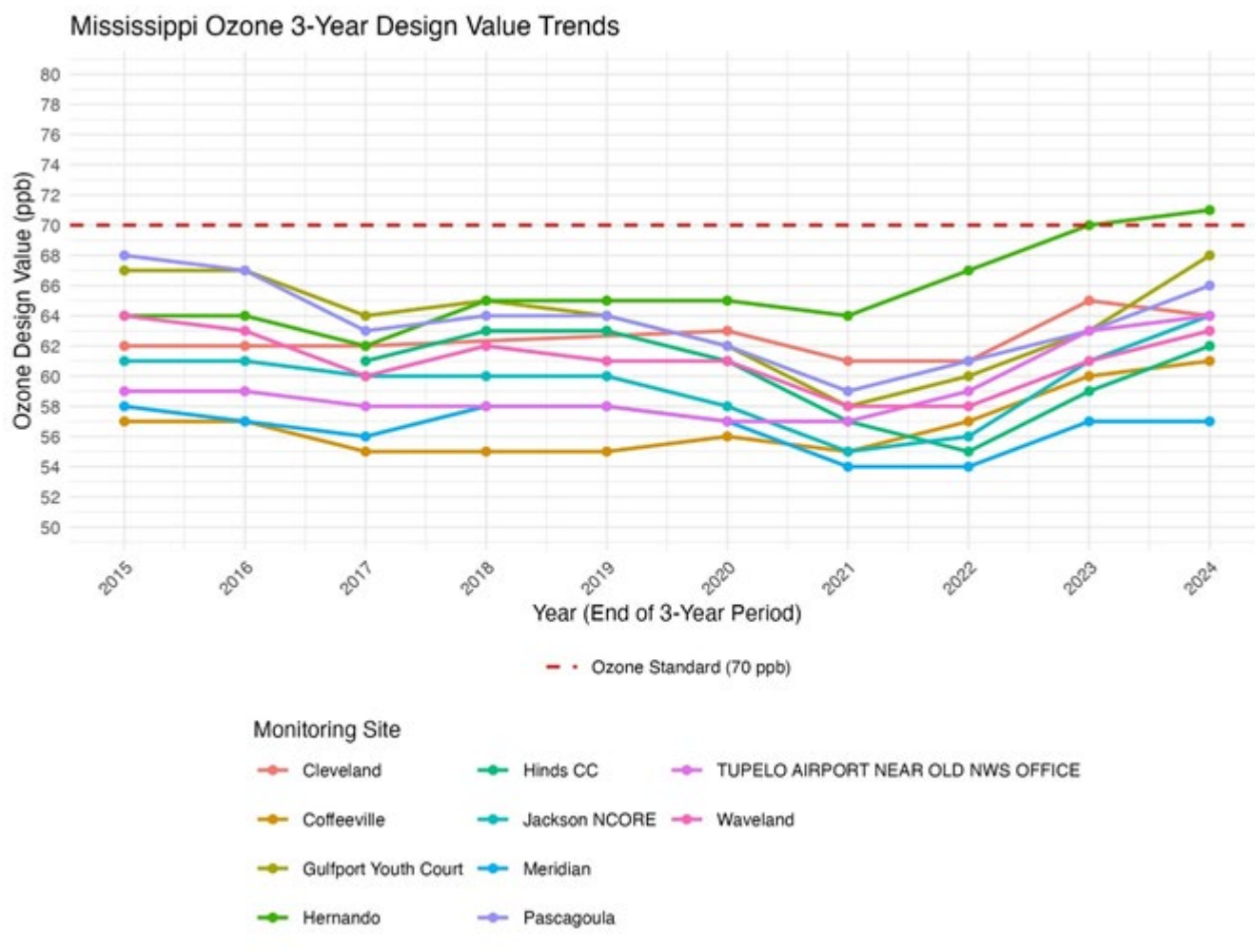
Site	County	Design Value (ppb)
Cleveland Delta State	Bolivar	64
Hernando	DeSoto	71
Waveland	Hancock	63
Gulfport Youth Court	Harrison	68
Hinds CC	Hinds	62
Jackson N CORE	Hinds	64
Pascagoula	Jackson	66
Meridian	Lauderdale	57
TUPELO AIRPORT NEAR OLD NWS OFFICE	Lee	64
Coffeeville	Yalobusha	61



Data source: EPA Air Quality System (AQS)

MDEQ operates an ambient air quality network throughout the state of Mississippi and report their findings in the [“Mississippi Department of Environmental Quality Air Quality Data Summary.”](#) This report looks at the reported levels of the criteria pollutants at various monitoring sites located across the State and compares these levels to the NAAQS to determine how the state is doing in meeting these standards. There is one primary and secondary ozone standard, the 8-hour average. The level of the 8-hour Ozone standard is 70 ppb. MDEQ monitors ozone continuously from March 1 through October 31 each year at the monitoring sites with the exception for the MDEQ N CORE site located in Jackson, MS which monitors ozone year around.

## 10 Year Ozone Monitoring Trends All Mississippi Sites



### ***B. Modeling Procedure***

All estimates of ambient concentrations are to be based upon applicable air quality models, databases and other requirements specified in EPA’s Guideline on Air Quality Models in Appendix W of 40 CFR Part 51.

The EPA Memorandums, “[Guidance on the Development of Modeled Emission Rates for Precursors \(MERPs\) as a Tier I Demonstration Tool for Ozone and PM<sub>2.5</sub> under the PSD Permitting Program](#),” dated April 30, 2019, and “[Guidance for Ozone and Fine Particulate Matter Permit Modeling](#)” dated July 29, 2022 reflect EPA’s recommendation for how agencies conduct air quality modeling and related technical analyses to satisfy compliance demonstration requirements for ozone and PM<sub>2.5</sub> under the PSD Permitting Program. In accordance with the above-mentioned Guidance and the Revisions to the Guideline on Air

Quality Models (40 CFR Part 51, Appendix), EPA recommends that an applicant use a “two-tiered” demonstration approach to address single-source impacts on ozone and secondary PM<sub>2.5</sub>. 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<sub>2.5</sub> 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 NO<sub>x</sub>, 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 – Vicksburg Advanced Power Station proposed project of constructing new natural gas-fired combined cycle power plant has an anticipated increase of 1.656 ppb of ozone.

The USEPA’s Smith County hypothetical source (CUS 9) is located within the same airshed as the VAPS. The majority of project-related NO<sub>x</sub>, SO<sub>2</sub>, 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 308 tpy NO<sub>x</sub> emissions and 54 tpy SO<sub>2</sub> emissions. These emissions are closer to the modeled emissions for the USEPA’s 500 tpy hypothetical source than the USEPA’s 1,000 tpy or 3,000 tpy hypothetical source emission rates. The 500 tpy NO<sub>x</sub> and SO<sub>2</sub> hypothetical source MERP values will be used for this analysis. The proposed project includes an (annualized daily) increase 881 tpy VOC emissions. These emissions are closer to the modeled emissions for the USEPA’s 1,000 tpy hypothetical source than the USEPA’s 500 tpy or 3,000 tpy hypothetical source emission rates. The 1,000 tpy VOC hypothetical source MERP values will be used for this analysis.

### **Model Versions**

The model versions being used are

- AERMET version 24142
- Building Profile Input Program subroutine (version 04274)
- Providence/Oris LLC's "BEE-Line BEEST for Windows"

The following model options will be used in the application of the AERMOD modeling:

- A. Regulatory default option will be enabled for all pollutants.
- B. Elevated terrain will be used for modeling the area around VAPS.
- C. VAPS sources will be modeled at their actual release heights. None of the VAPS stacks exceed the calculated GEP height or 65 meters, whichever is greater.
- D. The NAD83 datum will be used for source, structure, and receptor location coordinates.
- E. Modeling receptors will be placed to a distance that clearly identifies the area of impact

### **Receptor Grid Spacing**

The receptor grids used in the preliminary and full impacts analyses are described in this Section. The NAD83 datum was used for the receptor UTM coordinates. Providence/ORIS, LLC's "BEE-Line BEEST for Windows" was used to calculate the appropriate domain boundaries. The USEPA AERMAP program will be used to calculate (interpolate) the terrain elevations and local terrain maximums using 1-arc-second (~30 meters) United States Geological Survey's National Elevation Dataset.

The receptor coverage utilized for the preliminary impact analyses will consist of the following:

- 1,000-meter spaced receptors to a distance of 30 km from the VAPS fence line to ensure that (1) the maximum predicted concentration is located, (2) all locations with predicted concentrations greater than the SILs were identified, and (3) that concentration gradients associated with the project related emissions clearly decrease in magnitude outside of the AOIs
- 500-meter spaced receptors to a distance of 5 km from the VAPS fence line
- 100-meter spaced receptors to a distance of 1 km from the VAPS fence line
- 25-meter spaced receptors to a distance of 300 meters from any VAPS fence line
- 25-meter spaced receptors along the VAPS fence line

The entire VAPS facility will be fenced. These receptor grids will be designed to capture the maximum off-property ground-level concentrations for all pollutants, operating scenarios, and review types. EML will ensure that the receptor spacing surrounding the location of the modeled maximum concentration will be 100 meters or less.

Only receptors with predicted concentrations greater than or equal to the respective SILs were included in the full impact NAAQS and PSD increment consumption analyses. Full impact modeling receptor grids were developed using the preliminary modeling output.

Tier 1 estimates of the secondary PM<sub>2.5</sub> impacts calculated using the project-related NO<sub>x</sub> and SO<sub>2</sub> precursor emissions were added to the direct PM<sub>2.5</sub> modeling results for each individual modeling receptor for the significant receptor determination analyses. This is conservative since secondary PM<sub>2.5</sub> formed through chemical reactions will occur in the atmosphere gradually over time (hours or days depending on atmospheric conditions and other variables) and the estimated secondary PM<sub>2.5</sub> impact will not be likely to occur near the receptors with direct PM<sub>2.5</sub> impacts that are greater than the SILs.

#### **Meteorological Data**

Current MDEQ guidance was followed concerning meteorological data for AERMOD modeling for sources located in Warren County. The MDEQ has created county-specific preprocessed meteorological data sets using AERMET for use in AERMOD air dispersion modeling. Preprocessed meteorological data was obtained from the MDEQ. Warren County is located within the Southwest region of the State. Pre-processed meteorological data consisted of surface data from the Vicksburg/Tallulah Regional Airport meteorological station (KTVR) and upper air data from the Jackson International station. The MDEQ processed the data using AERMET version 24142 and incorporates the AERMINUTE data along with the low wind speed threshold of 0.5 m/s. The most recent five years of representative National Weather Service meteorological data available from the MDEQ on the date of the AQA (2020, 2021, 2022, 2023, and 2024) will be utilized in the NAAQS and PSD increment analyses. The base elevation for the Vicksburg / Tallulah Regional Airport station is 25.2 meters.

Guidance from the USEPA's Guideline on Air Quality Models, Appendix W 40 C.F.R. 51, EPAHQ-OAR-2015-0310, January 17, 2017 and the AERMOD Implementation Guide, 454-B-23-009, October 12, 2023 was followed to assess the representativeness of the data from this meteorological station location. These documents state that the determination of representativeness should include a comparison of the surface characteristics (albedo, Bowen ratio and surface roughness length) between the measurement site and the source location. The surface characteristics at both locations were determined using the USEPA's AERSURFACE tool using land cover data from the National Land Cover Database.

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**TABLE 6-1 SURFACE CHARACTERISTICS**

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<b>POLLUTANT</b>	<b>ALBEDO</b>	<b>BOWEN RATIO</b>	<b>SURFACE ROUGHNESS LENGTH (m)</b>
VAPS	0.15	0.38	0.078
Vicksburg / Tallulah Regional Airport	0.16	0.39	0.036

The surface characteristics at the VAPS are similar to those at the Vicksburg / Tallulah Regional Airport. The available surface roughness lengths can vary between 0.001 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 Vicksburg/Tallulah Regional Airport is the nearest surface station to the VAPS. The surface station and the VAPS are located within 11 km of each other. The land use immediately surrounding each location is rural in nature. The terrain surrounding each location and the terrain between each location is flat. The meteorology at each location will be similar.

**Point Source Stack Parameters**

MODELING STACK PARAMETERS - POINT SOURCES  
VICKSBURG ADVANCED POWER STATION  
VICKSBURG, MISSISSIPPI

Modeling ID	Description	Location (m), NAD83		Elevation (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)
		Eastings	Northing					
1A_B	Combined Cycle Unit 1A - Full Load	695414.6	3573938.9	32.18	60.96	344.26	24.76	7.010
1A_M	Combined Cycle Unit 1A - Medium Load	695414.6	3573938.9	32.18	60.96	351.97	21.44	7.010
1A_L	Combined Cycle Unit 1A - Low Load	695414.6	3573938.9	32.18	60.96	351.52	20.60	7.010
1A_MSS	Combined Cycle Unit 1A - MSS Startup Actuals	695414.6	3573938.9	32.18	60.96	351.52	20.60	7.010
1A_MSSH	Combined Cycle Unit 1A - MSS Hot Startup	695414.6	3573938.9	32.18	60.96	351.52	20.60	7.010
1A_MSSW	Combined Cycle Unit 1A - MSS Warm Startup	695414.6	3573938.9	32.18	60.96	351.52	20.60	7.010
1A_MSSC	Combined Cycle Unit 1A - MSS Cold Startup	695414.6	3573938.9	32.18	60.96	351.52	20.60	7.010
NGDPHTR	Natural Gas Dewpoint Heater	695442.6	3573908.3	32.18	6.096	394.26	4.133	0.5080
EMGEN	Emergency Standby Generator	695273.1	3573863.6	32.18	4.826	799.26	91.28	0.3556
FWP	Emergency Diesel Fire Water Pump	695351.7	3574083.9	32.18	4.877	789.26	36.22	0.1524
LOV_TURB	Combustion Turbine Lube Oil Vent	695359.6	3573872.5	32.18	9.144	0	0.001	0.001
LOV_STM	Steam Turbine Lube Oil Vent	695316.8	3573917.9	32.18	9.144	0	0.001	0.001

PHYSICAL EXHAUST PARAMETERS - POINT SOURCES  
VICKSBURG ADVANCED POWER STATION  
VICKSBURG, MISSISSIPPI

EPN	Modeling ID	Description	Location (m), NAD83		Base Elevation (ft)	Height (ft)	Diameter (ft)	Velocity (ft/sec)	Temp (°F)
			Eastings	Northing					
VAPS-1A	1A_B	Combined Cycle Unit 1A - Full Load	695414.6	3573938.9	105.58	200	23	81.25	160
VAPS-1A	1A_M	Combined Cycle Unit 1A - Medium Load	695414.6	3573938.9	105.58	200	23	70.34	174
VAPS-1A	1A_L	Combined Cycle Unit 1A - Low Load	695414.6	3573938.9	105.58	200	23	67.60	173
VAPS-1A	1A_MSS	Combined Cycle Unit 1A - MSS Startup Actuals	695414.6	3573938.9	105.58	200	23	67.60	173
VAPS-1A	1A_MSSH	Combined Cycle Unit 1A - MSS Hot Startup	695414.6	3573938.9	105.58	200	23	67.60	173
VAPS-1A	1A_MSSW	Combined Cycle Unit 1A - MSS Warm Startup	695414.6	3573938.9	105.58	200	23	67.60	173
VAPS-1A	1A_MSSC	Combined Cycle Unit 1A - MSS Cold Startup	695414.6	3573938.9	105.58	200	23	67.60	173
VAPS-NGDPHTR	NGDPHTR	Natural Gas Dewpoint Heater	695442.6	3573908.3	105.58	20.00	1.67	13.56	250
VAPS-EMGEN	EMGEN	Emergency Standby Generator	695273.1	3573863.6	105.58	15.83	1.17	299.5	979
VAPS-FWP	FWP	Emergency Diesel Fire Water Pump	695351.7	3574083.9	105.58	16.00	0.50	118.8	961
VAPS-LOVCT	LOV_TURB	Combustion Turbine Lube Oil Vent	695359.6	3573872.5	105.58	30.0			
VAPS-LOVST	LOV_STM	Steam Turbine Lube Oil Vent	695316.8	3573917.9	105.58	30.0			

**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 ( $\mu\text{g}/\text{m}^3$ )		SIGNIFICANT MONITORING CONCENTRATION ( $\mu\text{g}/\text{m}^3$ )
		1 <sup>st</sup> High (of 5 Years)	0.8639	
NO <sub>2</sub>	Annual	1 <sup>st</sup> High (of 5 Years)	0.8639	14
CO	8-Hour	1 <sup>st</sup> High (of 5 Years)	111.5	575
PM <sub>10</sub>	24-Hour	1 <sup>st</sup> High (of 5 Years)	1.374	10

### 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 PM<sub>2.5</sub>, 1-hour NO<sub>2</sub> and O<sub>3</sub>. EML proposes to use ambient air quality data from existing air quality monitoring stations to establish representative background concentrations for these contaminants. This facility will be fenced.

### Monitor Selection and Justification

Based on a review of the USEPA's AirData website, EML proposes using data collected at the following monitoring stations to establish representative background concentrations and for use in the NAAQS compliance demonstrations:

- PM<sub>2.5</sub> – Crossett (EPA ID 05-003-0005)
- NO<sub>2</sub> – Pride (EPA ID 22-033-0013)
- O<sub>3</sub> – Hinds CC (EPA ID 28-049-0021)

USEPA Guidance will be followed in selecting the form of the monitored concentration for each pollutant and averaging period.

TABLE 11-1 PROPOSED BACKGROUND CONCENTRATION

CONTAMINANT	MONITORING STATION	COUNTY	AVERAGING PERIOD	CONCENTRATION (µG/M <sup>3</sup> )	FORM
PM <sub>2.5</sub>	Crossett	Ashley, AR	24-Hour	19.27	3-Year Average of 98 <sup>th</sup> Percentiles of the Daily Maximums 2022-2024
			Annual	8.275	3-Year Average of 1 <sup>st</sup> Highs 2022-2024
NO <sub>2</sub>	Pride	East Baton Rouge, LA	1-Hour	20.04	3-Year Average of 98 <sup>th</sup> Percentiles of the Daily 1-Hour Maximums 2022-2024
			Annual	3.645	3-Year Average of 1 <sup>st</sup> Highs 2022-2024
O <sub>3</sub>	Hinds CC	Jackson, MS	8-Hour	62 PPB	3-Year Average of the 4 <sup>th</sup> Highest Daily 8-Hour Maximums 2022-2024

The NO<sub>2</sub> and O<sub>3</sub> concentrations were calculated using data obtained from annual summary tables obtained on the USEPA website. The PM<sub>2.5</sub> concentrations were calculated using the daily monitor PM<sub>2.5</sub> concentration data records for the Crossett monitor obtained on the USEPA Air Quality System (AQS) website. The data collected from these monitors meet the USEPA requirements for completeness

Following guidance contained in USEPA’s Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-007, May 1987; and USEPA’s Guidance on Developing Background Concentrations for Use in Modeling Demonstrations, November 20, 2024. EML concludes that the air quality monitoring data used to establish background concentrations is representative of the area around the VAPS facility.

The VAPS facility is located outside the “same general area” of the proposed monitoring stations. There are no NO<sub>2</sub>, PM<sub>2.5</sub> or O<sub>3</sub> ambient air monitoring stations located within Warren County. Therefore, topography, population and air emission information compiled for Warren County were compared to the proposed monitor locations.

Topography

The VAPS facility location and the proposed monitor location share similar topography. The area within several kilometers of each location is relatively flat, and largely undeveloped with rural characteristics.

Population Density

Population estimates were obtained from the U.S. Census Bureau for year 2024. Using these estimates, the population of Warren County was compared to the populations the Counties where the proposed monitor stations are located.

TABLE 11-2 POPULATION COMPARISON ANALYSIS

COUNTY	POPULATION ESTIMATE FOR YEAR 2024
Warren, MS	42,105
Ashley, AR	17,984
East Baton Rouge, LA	453,002
Jackson, MS	147,002

East Baton Rouge Parish and Jackson County has a significantly greater population than Warren County. Hence, air emissions associated with population density (e.g., automobile traffic) and corresponding ambient air concentrations monitored by the station will be greater than the emissions associated with population density expected to exist near the VAPS facility. The proposed NO<sub>2</sub> monitoring station offers conservative estimates for emissions associated with population density in Warren County. Ashley County has similar populations to Warren County. EML believes the Crossett monitoring station would offer representative PM<sub>2.5</sub> concentration estimates for the VAPS location.

Ozone is formed through photochemical reactions involving the emission of precursor compounds such as NO<sub>x</sub> and VOC. These chemical transformations occur in the atmosphere gradually over time. Due to the required formation distances, comparison of nearby (i.e. countywide) ozone precursor emissions (i.e., NO<sub>x</sub> and VOC) is not appropriate. However, it is noted that the county-wide population of Jackson County support the proposed Hinds CC O<sub>3</sub> monitor selection for representative concentration estimates for the VAPS location.

County-Wide Emissions

Air emission rate data for Warren and the proposed monitor Counties were obtained from USEPA’s National Emissions Inventory (NEI) Database through the USEPA AirData website. These USEPA AirData correspond to the point source and non point/mobile source criteria pollutant emissions for the 2020 NEI analysis (Version March 30, 2023). The USEPA is currently developing the 2023 NEI analysis and 2023 data is not yet available.

TABLE 11-3 COMPARISON OF COUNTY-WIDE AIR EMISSIONS

COUNTY	COUNTY-WIDE AIR EMISSION ESTIMATES (TPY)		
	PM <sub>2.5</sub>	NO <sub>2</sub>	VOC
Warren, MS	1,448	4,737	28,167
Ashley, AR	987	1,702	21,476
East Baton Rouge, LA	7,364	17,256	36,229
Jackson, MS	2,661	10,196	27,055

The county-wide air NO<sub>2</sub> emissions for East Baton Rouge Parish are significantly greater than those in Warren County. The proposed NO<sub>2</sub> Pride monitor offers conservative estimates for background NO<sub>2</sub> concentrations at the VAPS location. The county-wide air PM<sub>2.5</sub> emissions for Ashley County are similar to those in Warren County. EML believes the proposed Crossett monitor offers representative PM<sub>2.5</sub> concentrations for the VAPS location.

Ozone is formed through photochemical reactions involving the emission of precursor compounds such as NO<sub>x</sub> and VOC. These chemical transformations occur in the atmosphere gradually over time. Due to the required formation distances, comparison of nearby (i.e., countywide) ozone precursor emissions (i.e., NO<sub>x</sub> and VOC) is not appropriate. However, it is noted that the county-wide NO<sub>2</sub> and VOC emissions in Jackson County support the proposed Hinds CC O<sub>3</sub> monitor selection for representative concentration estimates for the VAPS location

#### Nearby Source Emissions

The emissions from electrical power generating facilities located near the proposed PM<sub>2.5</sub> and NO<sub>2</sub> monitors were compared with those near the project site. The USEPA's Power Plants and Neighboring Communities Map website was used to identify power plants within 100 km of each monitoring station and their emissions. This USEPA database does not provide the PM<sub>2.5</sub> emissions associated with these power plants. However, the provided NO<sub>x</sub> and SO<sub>2</sub> pollutants are precursors to secondary PM<sub>2.5</sub> emissions. This comparison shows that the emissions near the Crossett and Pride monitors are significantly greater than those near the proposed VAPS location. EML believes the Crossett and Pride monitors provides conservative and representative estimates for the background PM<sub>2.5</sub> and NO<sub>2</sub> concentrations at the project site.

#### Available Ozone Monitoring Data

It would not be appropriate to base the selection of a representative O<sub>3</sub> monitor on emissions of nearby or county-wide sources. There are four O<sub>3</sub> monitors located within the VAPS airshed.

The topography at the locations of each of these monitor stations are similar to that at the VAPS location. These nearby monitors provide similar concentration results that are all well below the 70 parts per billion NAAQS. EML proposes the use of the monitor closest to the VAPS location – Hinds CC. It should be noted the use of one of the more conservative of these monitors would also provide comparable (i.e., acceptable) modeling results for this AQA.

TABLE 11-4 COMPARISON OF NEARBY OZONE MONITORS

MONITOR	COUNTY	DISTANCE TO VAPS (KM)	8-HOUR O <sub>3</sub> DESIGN VALUE (PPB)
Hinds CC	Jackson, MS	66	62
NCORE	Jackson, MS	70	64
Monroe Airport	Ouachita, LA	108	62
Cleveland Delta State	Bolivar, MS	164	64

**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<sub>2.5</sub>. 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<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>2.5</sub> and O<sub>3</sub> impacts associated with the precursor emissions. The secondary PM<sub>2.5</sub> and ozone impacts were estimated using guidance from the USEPA’s Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM<sub>2.5</sub> under the PSD Permitting Program, December 2, 2016, and Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM<sub>2.5</sub> under the PSD Permitting Program, April 30, 2019. MERPs derived using the USEPA’s photochemical modeling results for hypothetical sources located in Mississippi were used to estimate the air

quality of secondary PM<sub>2.5</sub> and ozone impacts associated with project-related emissions of NO<sub>x</sub>, SO<sub>2</sub>, and VOCs. These secondary PM<sub>2.5</sub> and ozone impacts were included in the preliminary impact determination, full impact NAAQS, and full impact PSD increment consumption analyses.

The USEPA hypothetical source photochemical modeling and the MERP analysis are both based on annual project emission rates. The proposed project's annual emissions were used for the annual PM<sub>2.5</sub> analysis. The maximum daily project emissions were converted to tons per year (tpy) values for use in the short-term PM<sub>2.5</sub> and O<sub>3</sub> analyses. The turbine emission contributions were based on one hot startup each day and the remainder of the day at the turbine load scenario with the maximum hourly emission rates (base load operation with maximum duct burner firing at a 10°F ambient temperature day). This is extremely conservative since most days will not have a hot startup and the load scenario chosen for this analysis has higher emissions than those associated with alternative load scenarios.

The USEPA's Smith County hypothetical source (CUS 9) is located within the same airshed as the VAPS. The majority of project-related NO<sub>x</sub>, SO<sub>2</sub>, 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 308 tpy NO<sub>x</sub> emissions and 54 tpy SO<sub>2</sub> emissions. These emissions are closer to the modeled emissions for the USEPA's 500 tpy hypothetical source than the USEPA's 1,000 tpy or 3,000 tpy hypothetical source emission rates. The 500 tpy NO<sub>x</sub> and SO<sub>2</sub> hypothetical source MERP values were used for this analysis. The proposed project includes an (annualized daily) increase 881 tpy VOC emissions. These emissions are closer to the modeled emissions for the USEPA's 1,000 tpy hypothetical source than the USEPA's 500 tpy or 3,000 tpy hypothetical source emission rates. The 1,000 tpy VOC hypothetical source MERP values were used for this analysis.

The conservative O<sub>3</sub> and secondary PM<sub>2.5</sub> impacts estimated using the MERP analysis were included in the preliminary impact determination and full-impact modeling analyses.

TABLE 12-3 AOI ANALYSIS RESULTS

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS AT EACH RECEPTOR (ug/m <sup>3</sup> )		SIGNIFICANT IMPACT LEVEL (SIL) (ug/m <sup>3</sup> )
NO <sub>2</sub>	1-Hour	5-Year Average of 1 <sup>st</sup> High	9.381	7.5
	Annual	1 <sup>st</sup> High (of 5 Years)	0.8639	1
CO	1-Hour	1 <sup>st</sup> High (of 5 Years)	938.0	2,000
	8-Hour	1 <sup>st</sup> High (of 5 Years)	111.5	500
PM <sub>10</sub>	24-Hour	1 <sup>st</sup> High (of 5 Years)	1.374	5
PM <sub>10</sub> (Increment)	Annual	1 <sup>st</sup> High (of 5 Years)	0.1193	1
PM <sub>2.5</sub> (Increment)	24-Hour	1 <sup>st</sup> High (of 5 Years)	1.424 **	1.2
	Annual	1 <sup>st</sup> High (of 5 Years)	0.1206 **	0.13
PM <sub>2.5</sub> (NAAQS)	24-Hour	5-Year Average of 1 <sup>st</sup> High	1.070 **	1.2
	Annual	5-Year Average of 1 <sup>st</sup> High	0.1088 **	0.13
O <sub>3</sub>	8-Hour	Conservative Estimate	1.656 PPB **	1 PPB

\*\* Includes estimated secondary PM<sub>2.5</sub> impact from Section 12.1.1 MERP analysis

\*\*\* Estimated O<sub>3</sub> impact from Section 12.1.1 MERP analysis

The predicted annual NO<sub>2</sub>, 1-hour CO, 8-hour CO, 24-hour PM<sub>10</sub>, annual PM<sub>10</sub> and annual PM<sub>2.5</sub> concentrations are less than their respective SILs. Additionally, the 24-hour PM<sub>2.5</sub> NAAQS concentration is less than the SIL. No additional modeling is required for these pollutants and averaging periods.

The predicted 1-hour NO<sub>2</sub> NAAQS, 24-hour PM<sub>2.5</sub> PSD increment and 8- Hour O<sub>3</sub> NAAQS concentrations are greater than their respective SILs. Therefore, full impact modeling analyses are required for these pollutants and averaging periods.

**Tier 1 Demonstration for Ozone (NAAQS)**

VOC MERP Calculation:

$$1.00ppb \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

$$1.00ppb \left( \frac{1000 \text{ tpy}}{0.0644147769 \text{ ug/m}^3} \right)$$

$$= 15,524 \text{ tpy}$$

NOx MERP Calculation:

$$1.00ppb \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

$$1.00ppb \left( \frac{500 \text{ tpy}}{2.595975176 \text{ ug/m}^3} \right)$$

$$= 192.61 \text{ tpy}$$

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

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***

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

***Modeled Air Quality Impact***

$$= (1\text{ppb ozone}) \left[ \left( \frac{881 \text{ TPY VOC}}{15,524 \text{ TPY VOC}} \right) + \left( \frac{308 \text{ TPY NOx}}{192.6 \text{ TPY NOx}} \right) \right]$$

***Modeled Air Quality Impact = 1.656 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<sub>2.5</sub> Secondary Impact Assessment**

**PM<sub>2.5</sub> 24-Hour**

SO<sub>2</sub> MERP Calculation:

$$1.2 \frac{\mu\text{g}}{\text{m}^3} \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

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

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

NOx MERP Calculation:

$$1.2 \frac{\mu g}{m^3} \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

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

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

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

$$\text{Modeled } PM_{2.5} \text{ 24 Hr Air Quality Impact} = \left( 1.2 \frac{\mu g}{m^3} \right) \left[ \left( \frac{53.7 \text{ TPY } SO_2}{3,120.09 \text{ TPY } SO_2} \right) + \left( \frac{308 \text{ TPY } NO_x}{13,008.44 \text{ TPY } NO_x} \right) \right]$$

$$\text{Modeled } PM_{2.5} \text{ 24 Hour Air Quality Impact} = 0.04907 \frac{\mu g}{m^3}$$

#### PM<sub>2.5</sub> Annual

SO<sub>2</sub> MERP Calculation:

$$0.13 \frac{\mu g}{m^3} \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

$$0.13 \frac{\mu g}{m^3} \left( \frac{500 \text{ tpy}}{0.0075118421 \frac{\mu g}{m^3}} \right)$$

$$= 8,653 \text{ tpy}$$

NO<sub>x</sub> MERP Calculation:

$$0.13 \text{ ug}/\text{m}^3 \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

$$0.13 \frac{\mu\text{g}}{\text{m}^3} \left( \frac{500 \text{ tpy}}{0.0019286179 \frac{\mu\text{g}}{\text{m}^3}} \right)$$

$$= 33,702.89 \text{ tpy}$$

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

$$\begin{aligned} \text{Modeled } PM_{2.5} \text{ Annual Air Quality Impact} \\ = \left( 0.13 \frac{\mu\text{g}}{\text{m}^3} \right) \left[ \left( \frac{30.37 \text{ TPY } SO_2}{8,653 \text{ TPY } SO_2} \right) + \left( \frac{222.8 \text{ TPY } NO_x}{33,702.89 \text{ TPY } NO_x} \right) \right] \end{aligned}$$

$$\text{Modeled } PM_{2.5} \text{ Annual Hour Air Quality Impact} = 0.001316 \frac{\mu\text{g}}{\text{m}^3}$$

**PM<sub>2.5</sub> NAAQS Assessment**

**PM<sub>2.5</sub> 24-Hour**

*5 Year Average of 1st High + Secondary Impact =*

$$1.021 \frac{\mu\text{g}}{\text{m}^3} + 0.04907 \frac{\mu\text{g}}{\text{m}^3}$$
$$= 1.070 \frac{\mu\text{g}}{\text{m}^3}$$

This value is below the SIL of  $1.2 \frac{\mu\text{g}}{\text{m}^3}$ . Therefore, no further analysis is required.

**PM<sub>2.5</sub> Annual**

*5 Year Average of 1st High + Secondary Impact =*

$$0.1069 \frac{\mu\text{g}}{\text{m}^3} + 0.001316 \frac{\mu\text{g}}{\text{m}^3}$$
$$= 0.1082 \frac{\mu\text{g}}{\text{m}^3}$$

This value is below the SIL of  $0.13 \frac{\mu\text{g}}{\text{m}^3}$ . Therefore, no further analysis is required.

**PM<sub>2.5</sub> At and Past 50+ km**

**PM<sub>2.5</sub> 24-Hour**

SO<sub>2</sub> MERP Calculation:

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

$$0.27 \frac{\mu g}{m^3} \left( \frac{500 \textit{ tpy}}{0.114196 \textit{ tpy}} \right)$$

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

NO<sub>x</sub> MERP Calculation:

$$0.27 \frac{\mu g}{m^3} \left( \frac{\textit{Selected Hypothetical MERP}}{\textit{MaxConc}} \right)$$

$$0.27 \frac{\mu g}{m^3} \left( \frac{500 \textit{ tpy}}{0.045347 \frac{\mu g}{m^3}} \right)$$

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

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

$$\text{Modeled } PM_{2.5} \text{ 24 Hr Air Quality Impact} = \left( 0.27 \frac{\mu g}{m^3} \right) \left[ \left( \frac{53.7 \textit{ TPY } SO_2}{1,182.97 \textit{ TPY } SO_2} \right) + \left( \frac{308 \textit{ TPY } NO_x}{2,977.04 \textit{ TPY } NO_x} \right) \right]$$

$$\text{Modeled } PM_{2.5} \text{ 24 Hour Air Quality Impact} = 0.04019 \frac{\mu g}{m^3}$$

This value is below the SIL of  $0.27 \frac{\mu g}{m^3}$ . Therefore, no further analysis is required.

**PM<sub>2.5</sub> Annual**

SO<sub>2</sub> MERP Calculation:

$$0.03 \frac{\mu g}{m^3} \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

$$0.03 \frac{\mu g}{m^3} \left( \frac{500 \text{ tpy}}{0.003951 \frac{\mu g}{m^3}} \right)$$

$$= 3,796.50721336 \text{ tpy}$$

NO<sub>x</sub> MERP Calculation:

$$0.03 \frac{\mu g}{m^3} \left( \frac{\text{Selected Hypothetical MERP}}{\text{MaxConc}} \right)$$

$$0.03 \frac{\mu g}{m^3} \left( \frac{500 \text{ tpy}}{0.001462 \frac{\mu g}{m^3}} \right)$$

$$= 10,259.9179207 \text{ tpy}$$

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

$$\begin{aligned} \text{Modeled } PM_{2.5} \text{ Annual Air Quality Impact} \\ = \left( 0.03 \frac{\mu g}{m^3} \right) \left[ \left( \frac{30.37 \text{ TPY } SO_2}{3,796.51 \text{ TPY } SO_2} \right) + \left( \frac{222.8 \text{ TPY } NO_x}{10,259.92 \text{ TPY } NO_x} \right) \right] \end{aligned}$$

$$\text{Modeled } PM_{2.5} \text{ Annual Hour Air Quality Impact} = 0.0008915 \frac{\mu g}{m^3}$$

This value is below the SIL of  $0.03 \frac{\mu\text{g}}{\text{m}^3}$ . Therefore, no further analysis is required.

### **Increment Consumption**

PSD increment consumption limits currently exist for NO<sub>2</sub>, SO<sub>2</sub>, PM<sub>10</sub>, and PM<sub>2.5</sub>. Compliance with the PSD increment consumption limits must be demonstrated for sources with PSD significant emissions. 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.

A preliminary impacts determination was first conducted using project-related emissions to determine if a detailed PSD increment consumption analysis is required. This process is described in greater detail in Section 5.2.2. A full impact analysis was then performed for applicable NO<sub>2</sub>, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions for comparison to the PSD increment consumption limits. This analysis included PSD increment-consuming emissions from sitewide VAPS sources and from applicable PSD increment-consuming emission sources affecting the project's impact area. Increment consuming sources include:

- Direct and precursor allowable emissions from the proposed new source.
- Direct and precursor actual emission changes that have occurred at existing sources since the minor source baseline date for the proposed source's baseline area.
- Direct and precursor actual emissions from any major stationary source permitted prior to October 20, 2010 (major source baseline date for PM<sub>2.5</sub>) for which construction on such permit commenced after October 20, 2010.
- Direct and precursor allowable emissions of permitted sources permitted after the minor source baseline date that are not yet fully operative, if applicable.

The USEPA defines the baseline area to include (1) the facility submitting the first PSD application after the pollutant's trigger date and (2) any areas where the proposed emissions of this facility have a significant impact. For this purpose, a significant impact is defined as an annual increase greater than one microgram per cubic meter ( $\mu\text{g}/\text{m}^3$ ) of the pollutant. In Mississippi, attainment status is listed by individual counties.

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.

**PM<sub>2.5</sub> Increment Assessment**

**PM<sub>2.5</sub> 24-Hour**

*1st High (of 5 Years) + Secondary Impact =*

$$1.374 \frac{\mu\text{g}}{\text{m}^3} + 0.04907 \frac{\mu\text{g}}{\text{m}^3}$$
$$= 1.423 \frac{\mu\text{g}}{\text{m}^3}$$

This value is not below the SIL of  $1.2 \frac{\mu\text{g}}{\text{m}^3}$ . Therefore, further analysis is required.

**PM<sub>2.5</sub> Annual**

*1st High (of 5 Years) + Secondary Impact =*

$$0.1187 \frac{\mu\text{g}}{\text{m}^3} + 0.001316 \frac{\mu\text{g}}{\text{m}^3}$$
$$= 0.12 \frac{\mu\text{g}}{\text{m}^3}$$

This value is below the SIL of  $0.13 \frac{\mu\text{g}}{\text{m}^3}$ . Therefore, no further analysis is required.

### ***E. PSD Full Impact Analysis Modeling Impacts***

A full impact analysis is required for any pollutant for which the proposed source's estimated ambient pollutant concentrations exceed prescribed significant ambient impact levels. This analysis expands the preliminary analysis in that it considers emissions from: the proposed source; existing sources; residential, commercial, and industrial growth that accompanies the new activity and the new source or modification. For SO<sub>2</sub>, PM<sub>10</sub>, PM<sub>2.5</sub> and NO<sub>2</sub>, the full impact analysis consists of separate analyses for the NAAQS and PSD increments.

The impact area is a circular area with a radius extending from the source to (1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or (2) a modeling receptor distance of 50 km, whichever is less.

#### **Minor Source Baseline**

Minor Source Baseline Date means the earliest date after the trigger date on which a new major stationary source or a major modification to an existing source subject to PSD submits a complete application. The minor source baseline date is pollutant and geographically specific. The trigger date for PM<sub>2.5</sub> is October 20, 2011. VAPS will establish the minor source baseline date in Warren County for PM<sub>2.5</sub>.

#### **NAAQS**

The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere. For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution and the modeled ambient impact caused by the applicant's proposed emissions increase and associated growth. The applicant is required, at a minimum, to explicitly model 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.

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

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS ( $\mu\text{g}/\text{m}^3$ )	BACKGROUND CONCENTRATION ( $\mu\text{g}/\text{m}^3$ )	NAAQS ( $\mu\text{g}/\text{m}^3$ )
NO <sub>2</sub>	1-Hour	5-Year Average of 98 <sup>th</sup> Percentiles of the Daily 1-Hour Maximums	3-Year Average of 98 <sup>th</sup> Percentiles of the Daily 1-Hour Maximums, 2020-2022	188
O <sub>3</sub>	8-Hour	Conservative Maximum (from MERP analysis)	3-Year Average of the 4 <sup>th</sup> Highest Daily 8-Hour Maximums	70 ppb

**TABLE 12-7 NAAQS ANALYSIS RESULTS**

POLLUTANT	AVERAGING PERIOD	MAXIMUM PREDICTED CONCENTRATIONS ( $\mu\text{g}/\text{m}^3$ )	BACKGROUND CONCENTRATION ( $\mu\text{g}/\text{m}^3$ )	TOTAL ( $\mu\text{g}/\text{m}^3$ )	NAAQS ( $\mu\text{g}/\text{m}^3$ )
NO <sub>2</sub>	1-Hour	123.4	20.04	143.5	188
O <sub>3</sub>	8-Hour	1.656 ppb*	62 ppb	63.66 ppb	70 ppb

\* Estimated secondary O<sub>3</sub> impact from Section 12.1.1 MERP analysis

**Ozone NAAQS Cumulative Analysis Impact**

*NAAQS Value > Modeled Air Quality Impact + Monitored Design Value*

$$70\text{ppb} > 1.656\text{ ppb} + 62\text{ ppb}$$

$$70\text{ppb} > 63.656\text{ ppb}$$

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.

**1-Hour NO<sub>2</sub> NAAQS**

*NAAQS Value > Modeled Air Quality Impact + Monitored Design Value*

$$188 \frac{\mu\text{g}}{\text{m}^3} > 123.4 \frac{\mu\text{g}}{\text{m}^3} + 20.04 \frac{\mu\text{g}}{\text{m}^3}$$

$$188 \frac{\mu\text{g}}{\text{m}^3} > 143.44 \frac{\mu\text{g}}{\text{m}^3}$$

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.

### **PSD Class II Increment**

A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Emissions increases that consume a portion of the applicable increment are, in general, all those not accounted for in the baseline concentration and specifically include:

- Actual emissions increases occurring after the major source baseline date, which are associated with physical changes or changes in the method of operation at a major stationary source; and
- Actual emissions increase at any stationary source, area source, or mobile source occurring after the minor source baseline date.

## 24-Hour PM<sub>2.5</sub> Increment

MODELING RUN SUMMARY  
VICKSBURG ADVANCED POWER STATION  
VICKSBURG, MISSISSIPPI

TYPE OF RUN	POLLUTANT	RUN NUMBER	FILE NAME	MET YEAR	GROUP	MAXIMUM OFF-PROPERTY IMPACTS (µg/m <sup>3</sup> )										
						1-HR		8-HR	24-HR		ANNUAL					
						H1H	AVG H1H	AVG H8H	H1H	AVG H1H	H2H	H1H	AVG			
Preliminary AOI	NO <sub>2</sub>	1001	pre03to30_2020-2024_01NOX_BASE	2020-2024	BASE		9.38084									
		1002	pre03to30_2020-2024_01NOX_MID	2020-2024	MID		9.38084									
		1003	pre03to30_2020-2024_01NOX_LOW	2020-2024	LOW		9.38084									
		1004	pre01to30plus_2020-2024_01NOX_SUSDA	2020-2024	SUSDA		7.81177									
		1005	pre03to30_2020_99NOX	2020	ALL										0.74656	
		1006	pre03to30_2021_99NOX	2021	ALL										0.86281	
		1007	pre03to30_2022_99NOX	2022	ALL										0.86394	
		1008	pre03to30_2023_99NOX	2023	ALL										0.70646	
		1009	pre03to30_2024_99NOX	2024	ALL										0.70537	
	CO	1010		pre03to30_2020-2024_01CO	2020-2024	BASE	269.3158									
				pre03to30_2020-2024_01CO		MID	269.3158									
				pre03to30_2020-2024_01CO		LOW	269.3158									
				pre03to30_2020-2024_01CO		SUSDH	898.5256									
				pre03to30_2020-2024_01CO		SUSDW	898.8478									
				pre03to30_2020-2024_01CO		SUSDC	937.9574									
		1011		pre03to30_2020-2024_08CO	2020-2024	BASE			28.53646							
				pre03to30_2020-2024_08CO		MID			28.53646							
				pre03to30_2020-2024_08CO		LOW			28.53646							
	PM <sub>10</sub>	1012		pre03to30_2020-2024_24PM10	2020-2024	BASE				1.37446						
				pre03to30_2020-2024_24PM10		MID				1.02605						
				pre03to30_2020-2024_24PM10		LOW				1.02605						
		1013	pre03to30_2020_99PM10	2020	ALL									0.10162		
		1014	pre03to30_2021_99PM10	2021	ALL									0.11928		
PM <sub>2.5</sub>	1018		pre03to30_2020-2024_24PM25_max	2020-2024	BASE				1.37446							
			pre03to30_2020-2024_24PM25_max		MID				1.02605							
			pre03to30_2020-2024_24PM25_max		LOW				1.02605							
	1019	pre03to30_2020_99PM25_max	2020	ALL									0.10162			
	1020	pre03to30_2021_99PM25_max	2021	ALL									0.11928			
1021	pre03to30_2022_99PM25_max	2022	ALL									0.11712				
1022	pre03to30_2023_99PM25_max	2023	ALL									0.10197				
1023	pre03to30_2024_99PM25_max	2024	ALL									0.10968				

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						1-HR		8-HR	24-HR		ANNUAL				
						H1H	AVG H1H	AVG H8H	H1H	AVG H1H	H2H	H1H	AVG		
Preliminary AOI	PM <sub>2.5</sub>	1024	pre03to30_2020-2024_24PM25_avg	2020-2024	BASE										
			pre03to30_2020-2024_24PM25_avg		MID				1.02095						
			pre03to30_2020-2024_24PM25_avg		LOW				0.88207						
Preliminary Near Field	NO <sub>2</sub>	1025	pre03to30_2020-2024_99PM25_avg	2020-2024	ALL									0.10753	
		1026	pre03at50_2020_99NOX	2020	ALL									0.01014	
		1027	pre03at50_2021_99NOX	2021	ALL									0.01135	
		1028	pre03at50_2022_99NOX	2022	ALL									0.01158	
		1029	pre03at50_2023_99NOX	2023	ALL									0.0099	
		1030	pre03at50_2024_99NOX	2024	ALL									0.0095	
	PM <sub>10</sub>	1031		pre03at50_2020-2024_24PM10	2020-2024	BASE				0.15012					
				pre03at50_2020-2024_24PM10		MID				0.08557					
				pre03at50_2020-2024_24PM10		LOW				0.06938					
		1032	pre03at50_2020_99PM10	2020	ALL									0.0081	
		1033	pre03at50_2021_99PM10	2021	ALL									0.0091	
		1034	pre03at50_2022_99PM10	2022	ALL									0.00924	
	PM <sub>2.5</sub>	1037		pre03at50_2020-2024_24PM25_max	2020-2024	BASE				0.15012					
				pre03at50_2020-2024_24PM25_max		MID				0.08557					
				pre03at50_2020-2024_24PM25_max		LOW				0.06938					
1038		pre03at50_2020_99PM25_max	2020	ALL									0.0081		
1039		pre03at50_2021_99PM25_max	2021	ALL									0.0091		
Full Impact, PSD Increment	NO <sub>2</sub>	1043	naq01no201_2020-2024_01NOX_SUSDA	2020-2024	SUSDA			62.75008							
		1049	naq03no201_2020-2024_01NOX_BASE	2020-2024	BASE			123.4154							
		1050	naq03no201_2020-2024_01NOX_MID	2020-2024	MID			123.4154							
		1051	naq03no201_2020-2024_01NOX_LOW	2020-2024	LOW			123.4154							
		1044	inc03pm2524_2020_24PM25	2020	BASE									0.95931	
	1045	inc03pm2524_2021_24PM25	2021	BASE									0.93841		
	1046	inc03pm2524_2022_24PM25	2022	BASE									1.09445		
	1047	inc03pm2524_2023_24PM25	2023	BASE									0.69495		
1048	inc03pm2524_2024_24PM25	2024	BASE									1.01552			

- Modeling runs numbered 1001 through 1025 represent the preliminary impact analysis modeling conducted for the proposed increases in NO<sub>2</sub>, CO, PM<sub>10</sub> and PM<sub>2.5</sub> allowable emissions.
- Modeling run numbers 1005 through 1009, 1011, and 1012 represent the preliminary modeling conducted for the proposed PSD-significant increases in NO<sub>2</sub>, CO, and PM<sub>10</sub>.
- Modeling run numbers 1026 through 1042 represent the preliminary modeling conducted for the proposed PSD-significant increases in NO<sub>2</sub>, PM<sub>10</sub>, and PM<sub>2.5</sub>.
- Modeling run number 1043 and 1049 through 1051 represents the full impact NAAQS modeling conducted for NO<sub>2</sub>.
- Modeling runs numbered 1044 through 1048 represent the full impact PSD Increment modeling conducted for PM<sub>2.5</sub>.

**TABLE 12-8 PSD INCREMENT CONSUMPTION ANALYSIS RESULTS**

<b>POLLUTANT</b>	<b>AVERAGING PERIOD</b>	<b>MAXIMUM PREDICTED CONCENTRATIONS AT EACH RECEPTOR (µg/m<sup>3</sup>)</b>	<b>PSD INCREMENT CONSUMPTION LIMIT (µg/m<sup>3</sup>)</b>
PM <sub>2.5</sub>	24-Hour	2 <sup>nd</sup> High (of 5 Years)	9

\* Includes estimated secondary PM<sub>2.5</sub> impact from Section 12.1.1 MERP analysis

The predicted PM<sub>2.5</sub> concentrations are less than the PSD increment consumption limits for all applicable averaging periods.

#### Vegetation and Soils Impact

The owner or operator is required to provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

The secondary NAAQS are set to "protect the public welfare from any known or anticipated adverse effects" associated with ambient concentrations of the pollutant. The term "welfare" is defined in the Clean Air Act to include "effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility, and climate." The modeled results were below the secondary NAAQS and, therefore, no adverse impact on soils and vegetation is anticipated.

## ***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 NO<sub>x</sub>, 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.

## ***G. Associated Growth Impact***

The MDEQ's AQMG states that "An in-depth growth analysis is only required if the project would result in a significant shift in population and associated activity into the area (i.e., a population increase on the order of thousands of people)." Employment within this area (i.e., within the modeling domain) will not significantly increase as a result of the proposed project. Also, there will not be any significant impacts due to any changes in the population size or density, or changes in the type of development in the area. Therefore, possible adverse impacts from this project are not expected.

## ***H. Class I Impact and Visibility***

The Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report – Revised (2010), provides recommendations, specific procedures, and interpretation of results for assessing visibility impacts of new or modified sources on Class I Area resources. Section 3.2., Initial Screening Criteria (New), presents a screening tool, Q/D, (where Q is the total SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>10</sub>, and H<sub>2</sub>SO<sub>4</sub> annual emissions divided by D, the distance from the Class I Area) to screen out from Air Quality Related Values (AQRV) review for those sources with relatively small amounts of emissions located a large distance from a Class

I Area. If this value is less than or equal to 10, the source will be considered to have negligible impacts with respect to Class I AQRV. The Federal Land Manager (FLM) (and the Federal official with direct responsibility for management of the Federal Class I parks as wilderness areas) will not request any further Class I AQRV impact analysis. As a minimum, the permitting authority should notify the FLM of all sources that exceed the Q/D criteria.

$$Q/D = \frac{(SO_2 + NO_x + PM_{10} + H_2SO_4)}{\text{Distance from Class I Area}}$$

VAPS is not located within 300km of a Class I area and therefore will not be required to perform a Q/D screening or an Air Quality Related Values (AQRV) impact analysis.

### ***I. Class II Impact and Visibility***

EML has extensive experience operating natural gas-fired combustion turbine 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 our extensive experience operating natural gas-fired combustion turbine EGUs, EML is confident in asserting that the VAPS 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.