AECOM

Prepared for:
Alabama Power Company
Birmingham, Alabama

Prepared by:
AECOM
Chelmsford, MA
60602366
February 2020

Air Construction Permit Application

Alabama Power Company
Plant Barry Units 8 and 9
Combined Cycle Project
Mobile County, Alabama

February 2020

Alabama Power

Contents

1.0 Introduction 1-1

1.1 Facility Description 1-1

1.2 Project Description 1-2

1.3 Project Location 1-3

1.4 Facility Classification 1-3

1.4.1 Standard Industrial Classification Code (SIC) 1-3

1.4.2 Air Quality Source Designation 1-3

1.5 Document Organization 1-7

2.0 Process Description 2-1

2.1 Combined Cycle Units 2-1

2.1.1 Combustion Turbine Generators 2-2

2.1.2 Heat Recovery Steam Generators 2-2

2.1.3 Steam Turbine Generator 2-2

2.2 Mechanical Draft Cooling Towers 2-2

2.3 Auxiliary Boiler 2-3

2.4 Diesel-Fired Emergency Generators 2-3

2.5 Diesel-Fired Fire Water Pump Engine 2-3

3.0 Project Emissions Summary 3-1

3.1 Combined Cycle Units 3-1

3.2 Ancillary Equipment 3-4

3.2.1 Auxiliary Boiler 3-4

3.2.2 Cooling Towers 3-4

3.2.3 Emergency Engines 3-4

3.3 Total Annual Project Emissions 3-5

4.0 Requirements and Standards 4-1

4.1 Ambient Air Quality Classification 4-2

4.2 Prevention of Significant Deterioration (PSD) Program 4-3

4.2.1 PSD Applicability 4-3

4.2.2 PSD Program Requirements 4-4

4.3 Good Engineering Practice (GEP) Stack Height Analysis 4-7

4.4 Applicability of New Source Performance Standards (NSPS) 4-7

4.4.1 Subpart A – General Provisions 4-7

4.4.2 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units 4-7

4.4.3 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units....4-8
4.4.4 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels....4-8
4.4.5 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines....4-8
4.4.6 Subpart KKKK – Standards of Performance for Stationary Combustion Turbine Emissions....4-8
4.4.7 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions from Electric Utility Generating Units....4-9
4.4.8 Non-Applicability of All Other NSPS....4-9

4.5 40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAPs)....4-9

4.6 40 CFR Part 63 NESHAPs....4-10
4.6.1 Subpart A – General Provisions....4-10
4.6.2 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines....4-10
4.6.3 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines....4-10
4.6.4 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters....4-11
4.6.5 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources....4-11
4.6.6 Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units....4-11

4.7 Acid Rain Program....4-11

4.8 Compliance Assurance Monitoring....4-12

4.9 Risk Management Program (RMP), Section 112(r)....4-12

4.10 Cross-State Air Pollution Rule....4-13

4.11 Greenhouse Gas Reporting Program....4-13

4.12 Other Applicable Alabama Rules and Regulations....4-13
4.12.1 ADEM Admin. Code r. 335-3-4-.01 – Visible Emissions....4-13
4.12.2 ADEM Admin. Code r. 335-3-4-.02 – Fugitive Dust and Emissions....4-14
4.12.3 ADEM Admin. Code r. 335-3-4-.03 –Fuel Burning Equipment....4-14
4.12.4 ADEM Admin. Code r. 335-3-4-.04 – PM from Process Industries....4-14
4.12.5 ADEM Admin. Code r. 335-3-5-.01 – SO_2 from Fuel Combustion....4-14
4.12.6 ADEM Admin. Code r. 335-3-8 – Nitrogen Oxide Emissions....4-15
4.12.7 ADEM Admin. Code r. 335-3-14 – Air Permits....4-15
4.12.8 ADEM Admin. Code r. 335-3-16 – Major Source Operating Permits....4-15

5.0 Control Technology Review....5-1

5.1 Technical Approach....5-1
5.1.1 Overview....5-1
5.1.2 BACT Assessment Methodology....5-3

5.2 BACT for Combined Cycle Units 5-5
5.2.1 BACT for Nitrogen Oxides Emissions 5-5
5.2.2 BACT for Carbon Monoxide Emissions 5-7
5.2.3 BACT for Volatile Organic Compound (VOC) Emissions 5-10
5.2.4 BACT for Particulate Matter Emissions 5-11
5.2.5 BACT for Sulfur Dioxide Emissions 5-13
5.2.6 BACT Associated with Startup and Shutdown 5-13
5.2.7 BACT for GHG Emissions 5-14

5.3 BACT for Auxiliary Boiler 5-31
5.3.1 BACT for Nitrogen Oxides Emissions 5-31
5.3.2 BACT for Carbon Monoxide and Volatile Organic Compound Emissions 5-33
5.3.3 BACT for Particulate Matter Emissions 5-35
5.3.4 BACT for Sulfur Dioxide Emissions 5-36
5.3.5 BACT for GHG Emissions 5-36

5.4 BACT for Emergency Diesel Generators and Fire Water Pump Engine 5-37
5.4.1 BACT for Nitrogen Oxides, Carbon Monoxide and Volatile Organic Compound Emissions 5-37
5.4.2 BACT for Particulate Matter Emissions 5-39
5.4.3 BACT for Sulfur Dioxide Emissions 5-40
5.4.4 BACT for GHG Emissions 5-41

5.5 BACT for Cooling Tower Particulate Matter Emissions 5-41
5.5.1 Step 1 - Available Cooling Tower PM Control Alternatives 5-42
5.5.2 Steps 2-4 - Technical Feasibility Assessment and Ranking of Cooling Tower PM Control Alternatives 5-42
5.5.3 Step 5 - Evaluation of BACT for Cooling Tower PM Control 5-42

5.6 Summary of Proposed BACT 5-42

6.0 Class II Area Air Quality Modeling Analysis Procedures 6-1

6.1 Modeling Source Approach and Configurations 6-2
6.1.1 Combined Cycles Pre- and Post-Upgrade 6-2
6.1.2 Ancillary Sources 6-7

6.2 Model Selection and Options 6-7

6.3 Dispersion Environment 6-7

6.4 Terrain 6-8

6.5 Good Engineering Practice Stack Height Analysis 6-8

6.6 Meteorological Data 6-9

6.7 Receptor Processing with AERMAP 6-10

6.8 Secondary $PM_{2.5}$ and Ozone - Approaches and Analyses 6-12
6.8.1 Approaches 6-12
6.8.2 Analyses 6-14

6.9 Background Air Quality and Pre-Construction Monitoring 6-15
6.9.1 Available Representative Ambient Air Quality Data 6-15
6.9.2 Pre-construction Monitoring 6-16

7.0 Class II Area Significant Impact Level Analysis Results 7-1

7.1 Load Analysis 7-1

7.2 Class II Area SIL Analysis 7-4

7.3 Pre-Construction Monitoring 7-5

8.0 Class II Area Cumulative Impact Analysis Results 8-1

8.1 Compliance with Class II Area Air Quality Standards and PSD Increments 8-1

8.2 Existing Source Inventory 8-1

8.3 NAAQS Analysis Results 8-2

8.4 PSD Increment Analysis Results 8-3

9.0 Other Requirements Potentially Applicable to Air Permits Authorizing Construction 9-1

9.1 Class I Area Impact Analysis 9-1

9.2 Soils and Vegetation 9-1

9.3 Growth Related Impacts 9-2

10.0 References 10-1

List of Appendices

Appendix A Application Forms

Appendix B Project Construction Schedule

Appendix C Plot Plan

Appendix D Emission Calculations

Appendix E Search Results from EPA's RACT/BACT/LAER Clearinghouse

Appendix F Greenhouse Gas BACT Supplemental Information

Appendix G Air Dispersion Modeling Files

Appendix H GEP Documentation

Appendix I Land Use Analysis

Appendix J AQS Reports

Appendix K Concentration Isopleths

List of Tables

Table 1-1: Milestone Activities 1-2
Table 3-1: Combined Cycle: Hourly and Annual Emissions during Normal Operations 3-2
Table 3-2: Combined Cycle: Annual PSD Emissions 3-3
Table 3-3: Combined Cycle: Annual Hazardous Air Pollutant (HAP) Emissions 3-3
Table 3-4: Annual PSD and HAP Emissions from Ancillary Equipment 3-5
Table 3-5: Total Project Potential to Emit Emissions 3-5
Table 3-6: Annual Project Potential to Emit HAP Emissions 3-6
Table 4-1: National Ambient Air Quality Standards 4-2
Table 4-2: Classification of Mobile County, AL, for each Criteria Pollutant 4-3
Table 4-3: PSD Significant Emission Rates 4-4
Table 4-4: PSD *De Minimis* Monitoring Threshold Concentrations 4-5
Table 4-5: Allowable PSD Increments and Significant Impact Levels (µg/m^3) 4-6
Table 4-6: Particulate Matter Emission Limits for Fuel Burning Equipment 4-14
Table 5-1: Power Generation Units with CCS in North America at Commercial Scale 5-19
Table 5-2: Commercial-Scale Saline Formation CO_2 Pumping and Storage Projects 5-24
Table 5-3: Summary of EPA RBLC Listings for Emergency Stationary Diesel Engines 5-38
Table 5-4: NSPS Subpart IIII Limits 5-39
Table 5-5: Proposed BACT Emission Limits and Compliance Demonstration Methods 5-42
Table 6-1: Allowable PSD Increments and Significant Impact Levels, (µg/m^3) 6-2
Table 6-2: Stack Exhaust Parameters and Emission Rates: Pre-Upgrade Configuration 6-4
Table 6-3: Stack Exhaust Parameters and Emission Rates: Post-Upgrade Configuration 6-5
Table 6-4: Composite Worst-Case Data (1) Modeling Inputs: Pre-Upgrade Configuration 6-6
Table 6-5: Composite Worst-Case Data (1) Modeling Inputs: Post-Upgrade Configuration 6-6
Table 6-6: Source Parameters and Criteria Pollutant Emission Rates for the Auxiliary Boiler 6-7
Table 6-7: Comparison of Project Precursor Emissions with Lowest MERPs 6-12
Table 6-8: 30-Year Climate Normals for Tallapoosa, Autauga, and Mobile Counties, Alabama. 6-13
Table 6-9: Project Estimated Secondary $PM_{2.5}$ Concentrations 6-14
Table 6-10: Project Estimated Ozone Concentrations 6-14
Table 6-11: 8-Hour Ozone Design Values for 2016-2018 6-15
Table 6-12: Monitored Background Concentrations 6-16
Table 6-13: *De Minimis* Monitoring Concentrations 6-16
Table 7-1: Load Analysis Modeling Results – Airport (AP) Land Use Characteristics 7-2
Table 7-2: Load Analysis Modeling Results – Plant Barry (SITE) Land Use Characteristics 7-3
Table 7-3: Summary of Load Analysis Results 7-4
Table 7-4: Summary of Maximum AERMOD Concentrations to Significant Impact Levels 7-5

Table 7-5: Comparison of Modeled Concentrations with Monitoring Exemption Concentrations..7-6
Table 8-1: Existing Plant Barry Sources Stack Parameters and Emission Rates.....8-2
Table 8-2: Summary of NAAQS Analysis 8-3
Table 8-3: Summary of PSD Increment Analysis 8-3
Table 9-1: Injury Threshold for Vegetation.....9-2

List of Figures

Figure 1-1: Location of Plant Barry (Aerial) 1-5
Figure 1-2: Location of Plant Barry (Topography).....1-6
Figure 5-1: Comparison of Coal and Natural Gas CCUS Issues 5-20
Figure 6-1: Land Use within 3 km of Plant Barry – Aerial Photo 6-17
Figure 6-2: Topography in the Vicinity of Plant Barry 6-18
Figure 6-3: Location of Meteorological Sites Relative to Plant Barry 6-19
Figure 6-4: Wind Rose for Mobile Regional Airport (2014-2018) 6-20
Figure 6-5: Proposed Ambient Air Boundary 6-21
Figure 6-6: Near-Field View of Receptor Grid.....6-22
Figure 6-7: Far-Field View of Receptor Grid 6-23
Figure 8-1: NAAQS Analysis Concentration Isopleths (includes ambient background).....8-4
Figure 8-2: PSD Increment Concentration Isopleths 8-6

1.0 Introduction

Alabama Power Company (Alabama Power) is proposing to construct and operate up to two (2) new natural gas-fired combined cycle (CC) electric generating units located at its Barry Steam Electric Generating Plant (Plant Barry). Plant Barry is located in Bucks, Alabama in Mobile County. When all stages of construction are completed, each new CC unit will have a nominal electric generating capacity of approximately 743 megawatts (MW) for a total capacity of approximately 1,486 MW for distribution on Alabama Power's electric grid. The new CC units, in their final configuration, along with all associated ancillary equipment, herein are referred to as the "Plant Barry Units 8 and 9 Combined Cycle Project" (or the "Project").

Plant Barry currently has two natural gas-fired steam electric generating units, two coal-fired steam electric generating units, and two 2-on-1 combined cycle electric generating units. Alabama Power is proposing to construct up to two new CC units each with a Mitsubishi Hitachi Power Systems (MHPS) M501JAC class natural gas-fired combustion turbine (CT) unit, a supplementary-fired (i.e. duct burner) Heat Recovery Steam Generator (HRSG) and a steam turbine generator. Each new CT/HRSG will be arranged in a 1-on-1 configuration.

Each CC unit will be capable of firing natural gas only. Each CC unit will be equipped with a selective catalytic reduction (SCR) system to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst system to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. The proposed Project will also include typical ancillary equipment for a combined cycle power plant such as an auxiliary boiler, emergency generators, fire water pump engine, and mechanical draft cooling towers.

Plant Barry is an existing "major source" of criteria air pollutants, and the Project is expected to be considered a major modification under Prevention of Significant Deterioration (PSD) permitting requirements for certain regulated pollutants. Specifically, Alabama Power expects the Project to be subject to PSD permitting for NO_X, sulfur dioxide (SO_2), particulate matter (PM) less than 10 microns in diameter (PM_{10}), PM less than 2.5 microns in diameter ($PM_{2.5}$), CO, greenhouse gases (GHG), and VOC. This application will also demonstrate that the Project will not result in a significant emissions increase of sulfuric acid mist (H_2SO_4) or lead (Pb). Therefore, these pollutants are not subject to PSD review and can be permitted under "minor" permitting guidelines. Total reduced sulfur (TRS) compounds are not formed as part of the processes associated with the Project, therefore TRS is not applicable. Also, fluoride emissions are not applicable to the Project.

This Introduction and the other components of this document constitute the application for an Air Permit Authorizing Construction in Clean Air Areas under the Alabama Department of Environmental Management (ADEM) Air Division Administrative Code. ADEM Admin. Code r. 335-3-14-.04. This application and supporting analyses address the applicable permitting requirements for the Project as well as the other reviews required by the State of Alabama, and demonstrate the Project is expected to comply with all applicable state and federal air quality regulations.

1.1 Facility Description

Alabama Power Company's Plant Barry is located on approximately 1,700 acres of land along the west banks of the Mobile River in Mobile County, Alabama. A facility location map is provided as Figure 1-1. The geographical coordinates for the approximate center of Plant Barry is:

- Universal Transverse Mercator (UTM) Easting: 403,550 meters;
- Universal Transverse Mercator (UTM) Northing: 3,430,450 meters;

- UTM Zone: 16;
- North American Datum (NAD): 1983;
- Elevation Above Mean Sea Level (AMSL): Approximately 25 feet AMSL.

Existing electric generating sources at Plant Barry include: two natural gas-fired boilers (Units 1 and 2), two coal-fired boilers (Units 4 and 5) and two 2-on-1 natural gas-fired combined-cycle blocks (Units 6A and 6B, 7A and 7B). Plant Barry also operates other smaller sources of air emissions such as Unit 5's auxiliary boiler, cooling towers, silo bin vents, emergency generators, fire pump engines and various small engines.

Units' 1, 2, 4, and 5 boilers are all tangentially fired and are each respectively capable of generating approximately 85, 85, 376, and 785 megawatts (MW) nominally. The two combined-cycle blocks (Units 6A and 6B, 7A and 7B) are each respectively capable of generating 557 and 554 MW nominally. Each of the combined cycle blocks is comprised of two CT/HRSGs which supply steam to a single steam turbine.

1.2 Project Description

As stated in Section 1.0, Alabama Power is proposing to construct up to two natural gas-fired CC units arranged in a 1-on-1 configuration. Each 1-on-1 unit will have a CT unit and a HRSG that will provide steam to a steam turbine generator. For this Project, Alabama Power has selected the MHPS M501JAC turbine; the nominal generating capacity of each CC unit will be 743 MW at the completion of the final stage of installation. Each unit will have installed turbine hardware such that the final capacity can be realized after planned manufacturer's upgrades to turbine components approximately four years after commercial operation. The balance of plant equipment will be sized and designed to support the planned turbine upgrade. Additionally, the proposed Project will allow for the construction of additional ancillary equipment and/or adjustments or replacements of existing facility support structures or equipment to support the construction of up to two (2) combined cycle units. The additional ancillary equipment, adjustments, and/or replacements would not be emissions units. An overall Project construction schedule is included in Appendix B. A summary of the key milestone activities is provided below in Table 1-1.

Table 1-1: Milestone Activities

Activity	Unit 8	Unit 9
Start of Construction	March 2021	March 2023
Commercial Operation	November 2023	November 2025
Turbine Upgrade	August 2027	August 2029

The CC units are the primary sources of air emissions associated with the proposed Project, but there are additional ancillary sources that are part of the Project that have air emissions. The ancillary equipment being proposed for the Project is listed below:

- One (1) natural gas-fired auxiliary boiler rated at approximately 90.5 mmBtu/hr of heat input;
- Up to two (2) emergency generators rated at approximately 1,500 kilowatts (kW) each operating on ultra-low sulfur diesel fuel (ULSD);
- One (1) emergency diesel fire water pump engine rated at approximately 316 brake horse power (bhp) operating on ultra-low sulfur diesel (ULSD) fuel; and

- Up to two (2) multi-cell mechanical draft cooling towers.

A more detailed description of the Project components is provided in Section 2.

1.3 Project Location

The proposed new combined-cycle units will be located at Plant Barry which is located in Mobile County, approximately 20 miles north of the City of Mobile. Figure 1-1 is an aerial map showing the location of Plant Barry and indicating the preliminary location of the CC units. The land use surrounding the Project consists of a mix of mostly swampland, forested areas, wetlands, water and industrial areas. The topography surrounding Plant Barry, as indicated in the topographic map in Figure 1-2, is characterized by mostly flat areas with occasional gently rolling hills. A plot plan showing the plant property, adjacent roadways, and source locations is presented in Appendix C.

1.4 Facility Classification

There are two major classification criteria for the proposed Project, one related to its industrial character, and the other to its potential to emit air contaminants. The designation of the facility under each of these is reviewed below.

1.4.1 Standard Industrial Classification Code (SIC)

The United States government has devised a method for grouping all business activities according to their participation in the national commerce system. The system is based on classifying activities into "major groups" defined by the general character of a business operation. For example, electric, gas and sanitary services, which include power production, are defined as a major group. Each major group is given a unique two-digit number for identification. Power production activities have been assigned a major group code “49”.

To provide more detailed identification of a particular operation, an additional two-digit code is appended to the major group code. In the case of power generation facilities, the two-digit code is “11” to define the type of production involved. Thus, the proposed Project is classified under the Standard Industrial Classification (SIC) code system as:

- Major Group 49 – Electric, Gas, and Sanitary Services
- Electric Services – 4911

The North American Industrial Classification System was introduced as a replacement for SIC codes in 1997. This system's organization is similar to the SIC codes. Under this system, this facility would be classified under 221112, Fossil Fuel Electric Power Generation.

1.4.2 Air Quality Source Designation

With respect to air quality, new and existing industrial sources are classified as either major or minor sources based on their potential -to -emit (PTE) air contaminants. This classification is also affected in part by whether the area in which the source is located has attained the National Ambient Air Quality Standards (NAAQS)[1]. An area is classified as unclassifiable/attainment if the ambient air quality concentration for a specific pollutant, as measured by an ambient monitor or indicated by air dispersion modeling, meets or is cleaner than the standard concentration level for a set of averaging periods. The area in which the proposed Project is located is designated as unclassifiable/attainment

[1] Criteria pollutants are those for which EPA has established NAAQS and consist of PM_{10}, $PM_{2.5}$, CO, NO_x, SO_2, lead, and ozone, which is formed through the photochemical reaction of VOC and NO_x in the atmosphere.

for all the NAAQS in which the United States Environmental Protection Agency (EPA) has issued a designation under Section 107 of the Clean Air Act.

For most activities, a major source is defined as one which has the PTE of 250 tons per year of any regulated air contaminant. For a certain set of 28 stationary source categories, the EPA has defined the major source emission threshold to be 100 tons per year. Steam-Electric Power Generation is one of these special groups. Based on its PTE, the proposed Project will be classified as a “major stationary source” of air emissions.

Figure 1-1: Location of Plant Barry (Aerial)

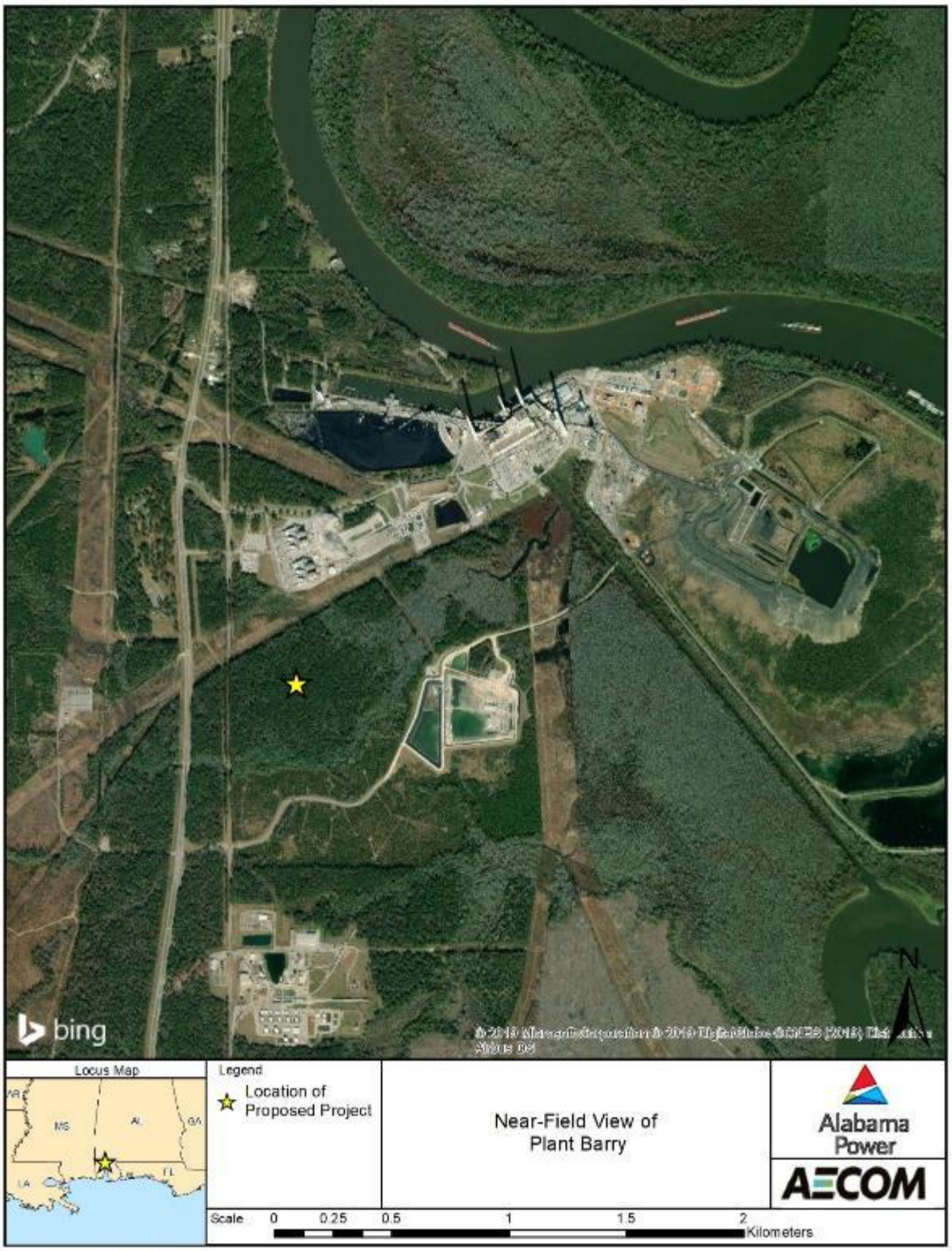
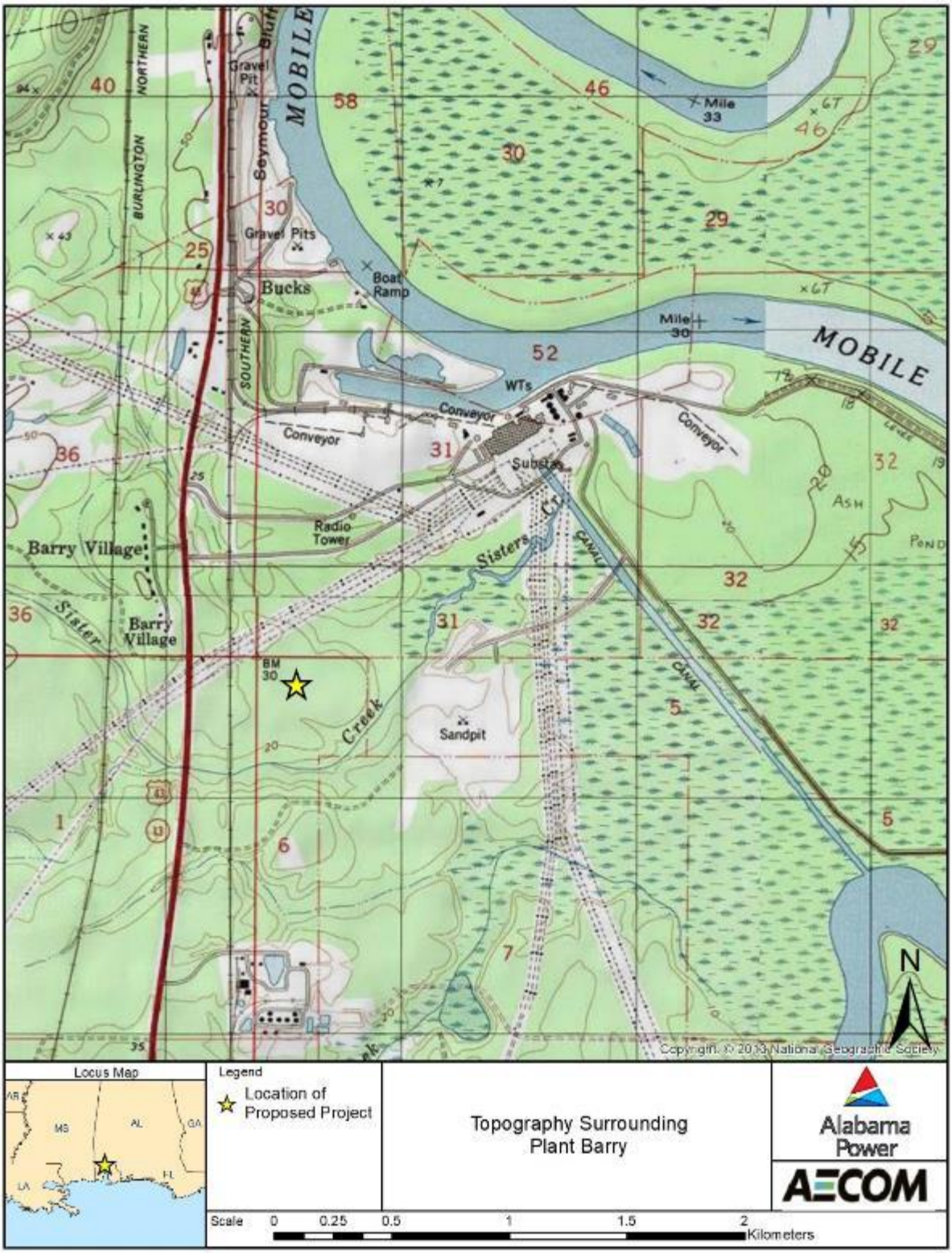


Figure 1-2: Location of Plant Barry (Topography)



1.5 Document Organization

The balance of this document is divided into sections which address each component of the PSD air quality review process. The outline below provides an overview of the contents of each of the remaining sections.

Section 2.0 – Process Description provides a general description of the primary combined-cycle processes by which power will be produced at this site as well as a description of the auxiliary and ancillary equipment.

Section 3.0 – Project Emissions Summary presents a detailed review of the air emissions which will occur at the Project site due to the operation of the new combined-cycle units and associated auxiliary and ancillary equipment.

Section 4.0 – Requirements and Standards presents a discussion of applicable State and Federal air regulations. The focus of this section will be on establishing which regulations are directly applicable to the proposed combined-cycle units and the ancillary equipment and proposed compliance demonstration.

Section 5.0 - Control Technology Review is a detailed evaluation of potential control technologies since the proposed Project will be classified as a major source for NSR pollutants and will result in a significant increase in the emissions of some NSR-regulated pollutants (as defined under the PSD regulations). Project emissions are projected to be significant for NO_X, PM_{10}, $PM_{2.5}$, VOC, SO_2, CO and GHG. As such, “top down” best available control technology (BACT) analyses for these pollutants have been provided for each emission unit.

Section 6.0 – Class II Area Air Quality Modeling Analysis Procedures summarizes the dispersion modeling methodology and the manner in which the predicted impacts were compared to the applicable standards. Specifically, this section discusses the modeling input data and the various modeling scenarios evaluated.

Section 7.0 – Class II Area Significant Impact Level (SIL) Analysis Results presents the results of the Class II Area SIL modeling results performed for the Project.

Section 8.0 – Class II Area Cumulative Impact Assessment Results presents the results of the Class II Area cumulative air dispersion modeling analysis performed for the Project. This section compares the modeled concentrations to the applicable standards to demonstrate that the Project will operate in compliance with air quality standards.

Section 9.0 – Other Requirements Potentially Applicable to Air Permits Authorizing Construction contains supplemental information regarding the potential impacts of the Project. Specifically, this section discusses the potential for impacts to Class I areas and soils and vegetation.

Section 10.0 - References will include a list of the documents relied upon during the preparation of this document.

Appendices – Appendices A, B, C D, E, and F provide permit application forms, project construction schedule, plot plan, emission calculations, and supporting BACT information. Additional information, figures and diagrams, dispersion modeling files on computer disc and supplemental materials supporting the information presented in the application are provided in Appendices G through K.

2.0 Process Description

As stated in Section 1, Alabama Power plans to construct up to two CC units arranged in a 1-on-1 configuration with additional ancillary equipment as part of the Project. The primary equipment of the proposed Project includes:

- Up to two (2) natural gas-fired MHPS M501JAC combustion turbines;
- One (1) pre-planned turbine component upgrade per CC unit to achieve final design efficiency and output;
- Up to two (2) HRSGs with supplementary natural gas-fired duct burners – one for each CC unit;
- Up to two (2) reheat condensing steam turbine generators – one for each CC unit;
- One (1) natural gas-fired auxiliary boiler rated at approximately 90.5 MMBtu/hr;
- Up to two (2) emergency generators rated at approximately 1,500 kW each operating on ULSD;
- One emergency fire water pump engine rated at approximately 316 bhp operating on ULSD; and
- Up to two (2) multi-cell wet mechanical draft cooling towers.

The proposed Project will have a net nominal generating capacity of up to approximately 1,486 MW at approximately 28°F ambient temperature. Each CC unit will be capable of firing natural gas only. The Project will employ Best Available Control Technology (BACT) to minimize emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$, CO, VOC, and GHG.

The primary sources of pollutants associated with the proposed project are the two combustion turbines and their associated natural gas-fired HRSGs. Other sources of criteria pollutants associated with the proposed project include the auxiliary boiler, emergency generators, fire water pump, and cooling tower. A brief description of the major components of the Project is provided in the following sections.

2.1 Combined Cycle Units

The CC units installed at Plant Barry will initially produce a gross output of approximately 744 MW each, (net output of approximately 726 MW) at site barometric pressure and humidity, but will be capable of additional output following planned replacement of some of the turbine components. After the turbine upgrade, timed to coincide with typical hot gas path inspection/replacement work for such units, the CC units will produce a gross output of approximately 761 MW (net output of approximately 743 MW) each. Accordingly, the emission calculations presented in Section 3 of this document address both the “pre-upgrade” and “post-upgrade” configurations. The BACT assessment presented in Section 5, focuses conservatively on the long-term future “post-upgrade” configuration of the CC units. The dispersion modeling assessments presented in Section 6 address both the “pre-upgrade” and “post-upgrade” configurations. Maximum annual operation of each CC unit will be 8,760 hours per year.

2.1.1 Combustion Turbine Generators

The combustion turbine is the main component of a combined-cycle unit, and it consists of a high efficiency compressor, combustor, and high efficiency turbine. First, air is filtered, cooled when the ambient air temperature is higher than 59°F, and compressed in a multiple stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Lean pre-mix dry low-NO_X combustors minimize NO_X formation during natural gas combustion. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator.

The combustion turbines are designed to operate in the dry low-NO_X mode, historically at loads from approximately 50 percent up to 100 percent rating while firing natural gas, but the operational load ranges can be below 50 percent as long as the CC meets performance and emissions' limits. The combustion turbines will have a gross output of approximately 457 MW each, when all stages of construction are completed.

2.1.2 Heat Recovery Steam Generators

The hot exhaust gas exiting the combustion turbine is ducted to a steam generator commonly known as a HRSG where steam is produced and subsequently used to generate additional electricity in a steam turbine generator. Each HRSG will be equipped with natural gas-fired duct burners to provide additional steam generation capacity.

A horizontal, natural circulation, three-pressure level HRSG will be used to extract heat from the exhaust of each combustion turbine. Exhaust gas, entering the HRSG at approximately 1,200°F, will be cooled to the 165°F to 200°F range by the time it leaves the HRSG exhaust stack. The heat recovered from the CT exhaust and from the supplementary natural gas-fired duct burners will be used in the combined-cycle unit for additional steam generation and subsequent electricity generation in a dedicated steam turbine. Each HRSG will include a high-pressure superheater, a high-pressure evaporator, high-pressure economizer, reheat sections (to reheat partially expanded steam), an intermediate-pressure superheater, an intermediate-pressure evaporator, an intermediate-pressure economizer, a low-pressure superheater, a low-pressure evaporator, and a low-pressure economizer. Selective catalytic reduction (SCR) and oxidation catalyst systems will be installed in each HRSG to control NO_X, CO, and VOC emissions.

2.1.3 Steam Turbine Generator

The proposed Project includes up to two reheat, condensing steam turbine generators (one for each CC unit) designed for variable pressure operation. The steam turbine consists of a combined high-pressure-intermediate pressure turbine and one low pressure turbine. The high-pressure portion of each steam turbine generator receives high-pressure super-heated steam from its associated HRSG and exhausts to the HRSG reheat section where it is combined with excess intermediate pressure steam from the HRSG. The HRSG increases the temperature of the steam and returns the steam to the intermediate-pressure section of the steam turbine generator, which expands to the low-pressure section. The low-pressure steam turbine generator also receives excess low-pressure superheated steam from the HRSG, exhausting all steam to a water-cooled condenser.

2.2 Mechanical Draft Cooling Towers

The proposed Project will include up to two 7-cell wet mechanical induced draft cooling towers that will provide cooling water to be used in the heat exchangers for the steam turbine generator exhausts. The cooling towers will be equipped with plume abatement features, including drift eliminators that will

reduce droplet drift from each cell to 0.0005% of the tower circulating water flow rate; the maximum design circulating water flow rate for all the cells combined will be 219,180 gallons per minute.

2.3 Auxiliary Boiler

Alabama Power proposes to install one auxiliary boiler rated at approximately 90.5 MMBtu/hr. The auxiliary boiler's primary purpose would be to supply sealing steam to the steam turbine generators at startup and at cold starts to warm up the steam turbine generator rotors. The auxiliary boiler will combust natural gas only and use low NO_X burners to control NO_X emissions. Alabama Power proposes for the boiler to be permitted to operate at a 100% annual capacity factor. The emissions calculations and the air quality modeling analysis reflect this assumption.

2.4 Diesel-Fired Emergency Generators

The proposed Project will include up to two ULSD-fired emergency generators rated at approximately 1,500 kW each that will be operated for emergency purposes including up to 100 hours per year for maintenance checks and readiness testing. The emergency diesel generators will provide power in emergency situations for turning gears, lubricate oil pumps, auxiliary cooling water pumps and water supply pumps. The emergency diesel generators are not intended to provide sufficient power for a black start, peak shaving or non-emergency use.

2.5 Diesel-Fired Fire Water Pump Engine

The proposed Project will include one ULSD-fired engine rated at approximately 316 bhp that will be operated as a fire water pump driver. The engine will be operated for emergency purposes including up to 100 hours per year for maintenance checks and readiness testing.

3.0 Project Emissions Summary

This section presents a summary of the Project emissions and a discussion of the methodologies used to calculate emissions. Within each emission source subsection below, the methods used to calculate emissions are discussed followed by a summary of the emission estimates for the specific source as well as, in the case of the CC units, mode of operation. Given the planned staged construction, emissions are presented for both the "Pre" and "Post" turbine upgrade configurations in Appendix D. The emission calculations in Appendix D illustrate the relatively small change in emissions between the "Pre" and "Post" turbine upgrade configurations. Section 3.1 below, provides a summary of the worst-case hourly and annual emissions associated with the proposed Project which happens to be associated with the "Post" turbine upgrade scenario for all applicable pollutants.

The Project emissions are projected based upon the following sources of air emissions:

- Two (2) natural gas-fired CC units;
- One (1) natural gas-fired auxiliary boiler rated at approximately 90.5 MMBtu/hr;
- Two (2) emergency generators rated at approximately 1,500 kW each operating on ULSD fuel;
- One (1) emergency fire water pump engine rated at approximately 316 bhp operating on ULSD fuel; and
- Two (2) multi-cell mechanical draft cooling towers.

The emissions calculation procedures used in determining the potential emissions from the Project are based on turbine information provided by the equipment manufacturer, other equipment vendor data, emission limitations specified by the applicable New Source Performance Standards, emission factors documented in EPA's "Compilation of Air Pollution Emission Factors, AP-42," the Electric Power Research Institute's (EPRI's) methodology[2] for calculating sulfuric acid emissions, and proposed BACT emission limits. Operational limitations (as appropriate) have been accounted for while estimating potential annual emissions.

Detailed emissions calculations for each emission source are presented in Appendix D.

3.1 Combined Cycle Units

The main sources of emissions for the Project are the two CC units. The following section presents the worst-case emission rates. Additional details such as emission and flow calculations at various loads, ambient temperature, with and without inlet conditioning, as provided by the turbine manufacturer are provided in Appendix D.

Each of the CC units is proposed to be operated up to 8,760 hours/year. Table 3-1 presents the maximum worst-case hourly emissions (lb/hr) and the annual emissions (tons per year) during normal operations for each CC unit.

[2] *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update. EPRI, Palo Alto, CA: 2018. 3002012398.*

Table 3-1: Combined Cycle: Hourly and Annual Emissions during Normal Operations

Pollutant	Maximum Hourly Emissions Per CC during Normal Operations(1) (lb/hr/CC)	Potential Annual Emission Rates Per CC during Normal Operations (tons/year/CC) (1) (2)
NO_X	39.1	167.3
CO	23.8	101.6
VOC	13.6	58.3
TSP(3)	6.8	28.7
$PM_{10}/PM_{2.5}$	21.5	90.2
SO_2	8.2	35.1
H_2SO_4	< 0.1	< 0.1
Lead	0.0024	0.0102
GHGs (CO_2e)(4)	571,808	2,445,022

(1) See Appendix D for detailed calculations
(2) Annual emissions (tons per year) are based on 8,760 hours per year firing natural gas
(3) TSP is filterable PM emissions only. PM_{10} and $PM_{2.5}$ includes both filterable and condensable PM emissions.
(4) CO_2e is the number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO_2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e

The Project has the capability to start up each CC unit independently of the other CC unit. Therefore, the startup time for each CC unit will be identical. Pollutant-specific annual emission rates for the two CC units were calculated based on vendor provided emissions data at 59˚F and the maximum of either 8,760 hr/year of continuous operation or emissions which include the maximum anticipated number of startup/shutdown events and the remaining hours at normal operating conditions, whichever is higher.

Annual emissions resulting from startup/shutdown operations for the proposed CC units are based on an anticipated worst-case annual schedule of 25 cold starts/year, 34 warm starts/year, 111 hot starts/year and 170 shutdowns/year. Under this assumption, the annual time associated with startup and shutdown accounts for approximately 473 hours per year. The remaining 8,278 hours per year were assumed to be under normal operating conditions. Table 3-2 presents the annual emissions (tons/year) of criteria pollutants, respectively, for the two CC units arranged in a 1-on-1 configuration for two cases:

(1) Continuous operations for both turbines at 8,760 hours per year in normal operations.
(2) Continuous operations for both turbines at 8,278 hours per year in normal operations and 473 hours per year in startup/shutdown operations.

The maximum emissions for all pollutants except for CO, VOC, and H_2SO_4 occur during 8,760 hours of normal continuous operation.

Table 3-2: Combined Cycle: Annual PSD Emissions

Pollutant	Potential Annual Emission Rates (Per CC unit) (1)			Total for 2 CC Units (1)
	Annual Emissions for Continuous Operation (tpy)	Annual Emissions with Startup and Shutdown (tpy)	Worst-Case Annual Emissions (tpy)	Worst-Case Annual Emissions (Total) (tpy)
NO_X	167.3	165.6	167.3	334.6
CO	101.6	249.9	249.9	499.9
VOC	58.3	185.3	185.3	370.7
TSP	28.7	28.3	28.7	57.4
PM_{10} / $PM_{2.5}$	90.2	87.6	90.2	180.4
SO_2	35.1	33.9	35.1	70.2
H_2SO_4	< 0.1	0.1	0.1	0.2
Lead	0.0102	0.0099	0.0102	0.0205
GHG (CO_2e)	2,445,022	2,360,878	2,445,022	4,890,045

(1) See Appendix D for detailed calculations.

Table 3-3 presents the annual hazardous air pollutant (HAP) emission estimates for the combined cycle units. AP-42 emission factors were used to calculate the HAP emissions with the exception of formaldehyde which was calculated based on vendor provided emissions data. The emissions calculations assume 8,760 hours per year of continuous operation.

Table 3-3: Combined Cycle: Annual Hazardous Air Pollutant (HAP) Emissions

Pollutant	Annual HAP Emissions(1) Total for 2 CC Units (tpy)
Arsenic	8.42E-03
Beryllium	5.05E-04
Cadmium	4.63E-02
Chromium (total)	5.90E-02
Cobalt	3.54E-03
Lead	2.11E-02
Manganese	1.60E-02
Mercury	1.10E-02
Nickel	8.84E-02
Selenium	1.01E-03
Acetaldehyde	1.72E+00
Acrolein	2.75E-01
Benzene	5.16E-01
Ethylbenzene	1.37E+00
Formaldehyde	9.89E+00
Naphthalene	5.58E-02
Polycyclic Aromatic Hydrocarbons (PAHs)	9.45E-02
Toluene	5.58E+00
Xylene	2.75E+00
TOTAL	**22.52**

(1) See Appendix D for detailed calculations.

3.2 Ancillary Equipment

The Project will include one auxiliary boiler and up to two multi-cell mechanical draft cooling towers to support CC unit operation. A fire water pump engine and two standby emergency generators will also be installed to meet the power and electricity demands of the facility during power outages and other emergencies. Emissions of criteria pollutants from the ancillary equipment are presented in Table 3-4 and detailed emissions calculations are provided in Appendix D (Tables D-9 to D-15).

3.2.1 Auxiliary Boiler

The Project will include one natural gas-fired auxiliary boiler with a rated heat input of 90.5 MMBtu/hr. The auxiliary boiler is being evaluated with a worst-case annual capacity factor of 100%. Emissions of criteria pollutants and HAPs from the auxiliary boiler are presented in Table 3-4 and detailed emissions calculations are presented in Appendix D (Tables D-9 and D-10).

3.2.2 Cooling Towers

Two 7-cell wet mechanical draft cooling towers with plume abatement will be incorporated to provide cooling water to the steam turbine condensers. Particulate matter emissions will be controlled by high efficiency drift eliminators which will limit drift to 0.0005% of the recirculated water rate. Emissions of criteria pollutants from the cooling towers are also presented in Table 3-4 and detailed emissions calculations are presented in Table D-11 of Appendix D.

3.2.3 Emergency Engines

The Project will also include up to two 1,500 kW emergency generators and a 316 bhp emergency fire water pump engine. The diesel-fired emergency generators and fire water pump engine will meet the emission requirements in EPA's Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart IIII. They will also meet the applicable requirements of 40 CFR Part 63, Subpart ZZZZ.

The fire water pump engine and the emergency generators will operate for emergency purposes and for no more than 100 hours/year for routine testing, maintenance, and non-emergency purposes, for each unit. Emissions of criteria pollutants and HAPs from the emergency engines are presented in Table 3-4 and detailed emissions calculations can be found in Appendix D (Tables D-12 through D-15).

Table 3-4: Annual PSD and HAP Emissions from Ancillary Equipment

Pollutant	Auxiliary Boiler Emissions (tpy)	Cooling Towers Emissions (tpy)	Emergency Generators Emissions (tpy)	Emergency Fire Water Pump Engine Emissions (tpy)
NOx	4.4	--	10.6	0.5
CO	14.7	--	5.8	0.5
VOC	1.6	--	10.6	0.5
SO2	0.7	--	0.012	0.001
TSP	0.8	12.0	0.3	0.03
PM_{10}	3.0	6.0	0.3	0.02
$PM_{2.5}$	3.0	0.02	0.3	0.02
Lead	0.0002	--	--	--
H_2SO_4	0.01	--	0.001	0.0001
GHG (CO_2e)	46,416	--	1429	85
HAPs	0.734	--	0.014	0.002

3.3 Total Annual Project Emissions

Table 3-5 provides the Project annual potential to emit PSD emissions for the worst-case scenario. Table 3-6 provides the annual potential to emit HAP emissions. As shown in Tables 3-5, the Project triggers PSD review for several pollutants. Total HAP emissions from the Project will not exceed 25 tons/year, and no individual HAP emissions will exceed 10 tons per year (see Appendix D for details).

Table 3-5: Total Project Potential to Emit Emissions

Source	Project PTE Pollutant Emissions (tpy)											
	TSP[1]	PM_{10}[1]	$PM_{2.5}$[1]	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	Fluorides	TRS	CO_2e[2]
CT & HRSG (Unit 8)	28.7	90.2	90.2	167.3	249.9	185.3	35.1	0.1	0.0102			2,445,022
CT & HRSG (Unit 9)	28.7	90.2	90.2	167.3	249.9	185.3	35.1	0.1	0.0102			2,445,022
Auxiliary Boiler	0.8	3.0	3.0	4.4	14.7	1.6	0.7	0.01	0.0002			46,416
Emergency Generators	0.3	0.3	0.3	10.6	5.8	10.6	0.012	0.001				1,429
Cooling Tower	12.0	6.0	0.02									
Fire Water Pump Engine	0.03	0.02	0.02	0.5	0.5	0.5	0.001	0.0001				85
Project Total	**70.5**	**189.7**	**183.7**	**350.2**	**520.7**	**383.4**	**70.9**	**0.2**	**0.02**	**N/A**	**N/A**	**4,937,975**
PSD Significance Level	25	15	10	40	100	40	40	7	0.06	3	10	75,000
PSD Review Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	No	No	No	**Yes**

[1] TSP is filterable PM emissions only. PM_{10} and $PM_{2.5}$ includes both filterable and condensable PM emissions.
[2] CO_2e is the number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO_2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e.

Table 3-6: Annual Project Potential to Emit HAP Emissions

Emission Source Description	HAP Estimates (tpy)
Combined Cycle Units	22.52
Ancillary Equipment	0.75
Project Total	**23.27**
Project Single Maximum HAP	**9.92**
See Table D-17 for detailed calculations.	

4.0 Requirements and Standards

As described in the previous sections, the Project consists of the following sources of air emissions:

- Up to two (2) natural gas-fired MHPS M501JAC combustion turbines;
- Up to two (2) HRSGs with supplementary natural gas-fired duct burners – one for each CC unit;
- Up to two (2) reheat condensing steam turbine generators – one for each CC unit;
- One (1) natural gas-fired auxiliary boiler rated at approximately 90.5 MMBtu/hr;
- Up to two (2) emergency generators rated at approximately 1,500 kW each operating on ULSD;
- One emergency fire water pump engine rated at approximately 316 bhp operating on ULSD; and
- Up to two (2) multi-cell mechanical draft cooling towers.

This section identifies the federal and state air quality regulations that will govern construction and operation of the proposed Project. Specifically, the following regulations and standards were reviewed for applicability to the proposed Project:

- National Ambient Air Quality Standards (NAAQS);
- Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Regulations;
- Good Engineering Practice (GEP) Stack Height Regulations;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Compliance Assurance Monitoring (CAM);
- Acid Rain Program Regulations (ARP);
- Risk Management Program (RMP);
- Cross-State Air Pollution Rule (CSAPR);
- Greenhouse Gas Reporting Program (GHGRP);
- Alabama Department of Environmental Management (ADEM), Air Division – Air Pollution Control Program; and
- Alabama State Implementation Plan.

The Federal regulatory programs, as administered and delegated by the U.S. Environmental Protection Agency (EPA), have been developed under the authority of the Clean Air Act (CAA or Act) and its amendments. These regulatory programs have been adopted by ADEM and are included in ADEM Admin. Code r. 335-3. The following subsections review the key elements of the regulatory programs and the impact they have on the permitting and operation of the proposed Project. Discussion of other applicable Alabama regulatory requirements is also included in this section.

4.1 Ambient Air Quality Classification

The 1970 CAA provides EPA with specific authority to establish National Ambient Air Quality Standards (NAAQS) for six common air pollutants in order to protect public health (primary standards) and welfare (secondary standards). The federally promulgated standards, adopted by ADEM, are presented in Table 4-1.

Table 4-1: National Ambient Air Quality Standards

Pollutant	Averaging Period[2]	NAAQS[1]	
		Primary	Secondary
Sulfur dioxide (SO_2)	Annual[4]	80	--[3]
	24-hour[4]	365	--[3]
	1-hour	196	--[3]
	3-hour	--[3]	1,300
Particulate matter (PM) with an aerodynamic diameter less than 10 microns (PM_{10})	24-hour	150	150
PM with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$)	Annual	12	15
	24-hour	35	35
Carbon monoxide (CO)	8-hour	10,000	--[3]
	1-hour	40,000	--[3]
Ozone (O_3)	8-hour	0.070 ppm	0.070 ppm
Nitrogen dioxide (NO_2)	Annual	53 ppb	53 ppb
	1-hour	100 ppb	--[3]
Lead (Pb)	3-month[5]	0.15	0.15

[1] All standards in this table are expressed in $\mu g/m^3$ unless otherwise noted.
[2] National short-term ambient standards may be exceeded once per year; annual standards may never be exceeded.
[3] No ambient standard for this pollutant and/or averaging period.
[4] Final rule signed June 2, 2010. The 1971 annual and 24-hour SO_2 standards were revoked in this rulemaking which became effective August 23, 2010. In addition, EPA's final rule establishing the initial air quality designations for certain areas in the United States (including Mobile County) became effective April 9, 2018.
[5] The rule signed October 15, 2008 finalized a new lead standard. On September 16, 2016, EPA issued a decision to retain without revision the existing 2008 standards. The entire state of Alabama is designated as unclassifiable/attainment as of July 20, 2018.
Source: 40 CFR 50

The 1990 CAA Amendments call for a review of the ambient air quality of all regions of the United States. By March 15, 1991, states were required to file with EPA designations of all areas as either attainment, nonattainment, or unclassifiable. Areas of the country that had monitored air quality levels equal to or better than these standards (i.e., ambient concentrations less than a standard) as of March 15, 1991, became designated as "attainment areas," while those areas where monitoring data indicated air quality concentrations greater than the standards became classified as "nonattainment areas."

The designation of "unclassifiable" indicates that there is insufficient monitoring data to demonstrate that the area has attained the federal standards; however, the limited data available indicates that the standard has been achieved. Areas with this classification are treated by the EPA as attainment areas for permitting purposes.

The Project will be located at Alabama Power Company's Barry Steam Electric Generating Plant (Plant Barry), which is situated in Bucks, Mobile County, Alabama. The current federal air quality classifications for the Project site in Mobile County are listed in Table 4-2 for each criteria pollutant. The designation of an area is important for a proposed project as it is a factor that, in part, determines whether a pollutant is subject to Prevention of Significant Deterioration (PSD) review or Nonattainment New Source Review (NNSR).

Table 4-2: Classification of Mobile County, AL, for each Criteria Pollutant

Pollutant	Attainment Status
Carbon Monoxide (CO)	Unclassifiable/Attainment
Sulfur Dioxide (SO_2)	Unclassifiable or better than national average
Nitrogen Dioxide (NO_2)	Unclassifiable or better than national average
Particulate Matter < 10 µm (PM_{10})	Unclassifiable/Attainment
Particulate Matter < 2.5 µm ($PM_{2.5}$)	Unclassifiable/Attainment
Ozone (O_3 - 8-hour)	Attainment/Unclassifiable
Lead (Pb)	Unclassifiable/Attainment
Source: 40 CFR 81.301.	

Major new sources or major modifications to existing major sources located in attainment or unclassifiable areas are required to obtain a PSD permit prior to initiation of construction. Similar sources located in areas designated as nonattainment (or that adversely impact such areas) are required to undergo permitting under the provisions of the NNSR program. In either case, it is necessary as a first step to determine the air quality classification of a project site. For the proposed Project, only PSD review is applicable because the attainment status for Mobile County is either unclassifiable/attainment or unclassifiable for all applicable pollutants.

4.2 Prevention of Significant Deterioration (PSD) Program

4.2.1 PSD Applicability

For PSD applicability, the Project's potential to emit (PTE) is reviewed to determine whether it constitutes a major stationary source or a major modification. Plant Barry is defined as a major stationary source because it is one of the 28 major source types listed in ADEM Admin Code r. 335-3-14-.04(2)(a)(1), and it has the potential to emit more than 100 tons per year of at least one NSR regulated pollutant. A major modification is defined as a physical or operational change at a major source that results in a net increase in emissions above the PSD significant emission rates, as identified in Table 4-3.

Table 4-3: PSD Significant Emission Rates

Pollutant	Significant Emission Rate[1] (tpy)
CO	100
NO_X	40
SO_2	40
PM	25
PM_{10}	15
$PM_{2.5}$	10
O_3	40 of VOC or NO_X
Lead (Pb)	0.6
Fluorides (excluding HF)	3
Sulfuric Acid Mist (H_2SO_4)	7
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10
Greenhouse Gases (as CO_2e)	75,000
(1) Source: ADEM Admin. Code r. 335-3-14-.04(2)(w)	

The Project will have emission increases above the PSD significance levels for NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, CO, SO_2, and GHG, as previously shown in Table 3-5. Therefore, PSD review is required for these pollutants.

4.2.2 PSD Program Requirements

The following sections provide a summary of the application requirements for projects subject to permitting under PSD.

Best Available Control Technology

The requirements for Best Available Control Technology (BACT) were promulgated within the framework of the PSD regulations in the 1977 CAA Amendments. Guidelines for the evaluation of BACT can be found in EPA's Air Pollution Control Cost Manual (EPA 2018) and in the Draft New Source Review Workshop Manual (EPA 1990). These guidelines were drafted by EPA as a framework or tool for the BACT process. EPA has also published guidance on BACT for greenhouse gas emissions (http://www.epa.gov/nsr/ghgpermitting.html). ADEM has developed its own PSD regulations that have been approved by the EPA and incorporated into the Alabama SIP under ADEM Admin Code r. 335-3-14-.04.

The BACT analysis for the Project is presented in Section 5.

Air Quality Monitoring Requirements

In accordance with requirements of ADEM Admin. Code r. 335-3-14-.04, a PSD permit application must contain an analysis of existing ambient air quality data in the affected area for all regulated pollutants that the Project has the potential to emit in significant amounts. The analysis of existing air quality can be air monitoring data from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source.

Ambient air monitoring for a period of up to one year may be required to properly satisfy this monitoring requirement. ADEM may exempt a source from the ambient air quality monitoring analysis for a particular pollutant if the emissions increase of the pollutant would cause air quality impacts that are less than the significant monitoring concentrations contained in ADEM Admin. Code r. 335-3-14-.04(8)(h)(1) and Table 4-4 below.

Table 4-4: PSD *De Minimis* Monitoring Threshold Concentrations

Pollutant[(1)]	Averaging Period	Threshold Concentration ($\mu g/m^3$)
CO	8-hour	575
NO_2	Annual	14
SO_2	24-hour	13
PM_{10}	24-hour	10
O_3	NA	[(2)]

[1] Only showing pollutants which the proposed Project are subject to PSD review.
[2] No *de minimis* air quality level is provided for ozone. However, any net increase of 100 tons per year or more of VOC or NO_X subject to rule ADEM Admin. Code r. 335-3-14-.04 would be required to perform an ambient impact analysis including the gathering of ambient air quality data.
Source: From Table 6 of ADEM's Modeling Guidelines.

Source Impact Analysis

A source impact analysis must be performed for a proposed project for each pollutant that triggers PSD review in order to demonstrate that the Project will not cause or contribute to a violation of any NAAQS or any applicable maximum allowable increase over the baseline concentration in any area. PSD regulations specify that new major sources or modifications to existing major sources may change baseline air quality only by a defined amount. This limited incremental degradation is known as a PSD increment. PSD increments have been established for Class I and Class II areas for PM_{10}, $PM_{2.5}$, SO_2, and NO_2 (see Table 4-5). The allowable change, or increment, is dependent on the classification of the area in which the action is to take place. When PSD regulations were first promulgated, three area classifications were proposed based on criteria set in the 1977 CAA.

Class I areas are federally protected areas and include specifically defined national parks, national forests, and wilderness areas. Class III increments are the least restrictive of the three PSD Classes, but to date, no Class III areas have been officially designated. The remainder (and vast majority) of the country (including Mobile County) is designated as a Class II area.

The PSD regulations specifically provide for the use of atmospheric dispersion modeling in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with NAAQS and allowable PSD increments. Designated EPA models, identified in 40 CFR Part 51, Appendix W, must normally be used in performing air quality analyses. Use of anything other than EPA-approved models requires written approval and opportunity for public notice and comment prior to use. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (GAQM, 40 CFR Part 51, Appendix W). The source impact analysis for criteria pollutants may be limited to only the new or modified sources if a net increase in impact due to the new or modified source is below the significant impact levels (SILs) presented in Table 4-5.

Various periods of meteorological data can be utilized for an impact analysis. A minimum 1-year period of onsite data, or a 5-year period of representative meteorological data is normally required.

Table 4-5: Allowable PSD Increments and Significant Impact Levels (µg/m^3)

Pollutant	Averaging Time	PSD Increments		SILs		NAAQS
		Class I	Class II	Class I[3]	Class II	
PM_{10}	Annual Arithmetic Mean[1]	4	17	0.2	1	NA
	24-hour Maximum[2]	8	30	0.3	5	150
$PM_{2.5}$[5]	Annual Arithmetic Mean[1]	1	4	0.06	0.3	12
	24-hour Maximum[2]	2	9	0.07	1.2	35
SO_2	Annual Arithmetic Mean[1]	2	20	0.1	1	NA
	24-hour Maximum[2]	5	91	0.2	5	NA
	3-hour Maximum[2]	25	512	1	25	1300
	1-hour Maximum[4]	NA	NA	NA	7.86	196
CO	8-hour Maximum	NA	NA	NA	500	10,000
	1-hour Maximum	NA	NA	NA	2000	40,000
NO_2	Annual Arithmetic Mean[1]	2.5	25	0.1	1	100
	1-hour Maximum[4]	NA	NA	NA	7.5	189

[1] PSD Increment not to be exceeded

[2] PSD Increment not to be exceeded more than once per year

[3] Class I SILs were proposed in FR July 23, 1996

[4] While there are no EPA promulgated SILs for the 1-hour SO_2 and NO_2 NAAQS, interim SIL values have been provided for Class II areas.

[5] SILs for $PM_{2.5}$ exist for the purpose of determining if a source has a significant contribution to a modeled violation. The SILs do not exist for the purposes of avoiding a cumulative impact analysis.

Notes: NA = Not applicable, i.e., no increment exists.

In addition to the standard air quality analyses, federal regulations require that applicants of PSD projects conduct an analysis of the impairment to visibility and the effects on soils and vegetation that would occur as a result of project construction and operation. Impacts due to commercial, residential, industrial, and other growth in the vicinity of the Project also must be addressed to the extent they are

a result of the proposed action. These additional requirements are addressed in Section 9 of this application.

4.3 Good Engineering Practice (GEP) Stack Height Analysis

The 1977 CAA requires that the degree of emission limitation required for control of any pollutant not be affected by a stack which exceeds the GEP height (EPA 1985). These requirements are described in more detail in Section 6.5.

4.4 Applicability of New Source Performance Standards (NSPS)

The NSPS subparts potentially applicable to this Project include:

- Subpart A – General Provisions;
- Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units;
- Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units;
- Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels;
- Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines;
- Subpart KKKK – Standards of Performance for Stationary Combustion Turbines; and
- Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units

ADEM has incorporated by reference these rules under ADEM Admin Code r. 335-3-10.

4.4.1 Subpart A – General Provisions

All affected sources which are subject to a NSPS under 40 CFR Part 60 are subject to the general provisions of 40 CFR Part 60 Subpart A, unless specifically excluded by the source-specific NSPS. Since the proposed Project will be subject to various NSPSs, the permittee will be required to comply with applicable provisions of Subpart A. Subpart A requires initial notification, performance testing, monitoring, and recordkeeping requirements for the subparts as applicable.

4.4.2 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Db applies to steam generating units which commence construction, modification, or reconstruction after June 19, 1984 and that have a maximum design heat input capacity greater than 100 MMBtu/hr. While the HRSG duct burners will have a maximum heat input capacity that exceeds this threshold, they are subject to the applicable requirements under 40 CFR Part 60 Subpart KKKK and are thus exempt from the applicable requirements of 40 CFR Part 60 Subpart Db. The proposed natural gas-fired auxiliary boiler will have a heat input capacity less than 100 MMBtu/hr and thus will not be subject to these requirements.

4.4.3 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc applies to steam generating units which commenced construction, modification, or reconstruction after June 9, 1989 and that have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The proposed natural gas-fired auxiliary boiler, rated at 90.5 MMBtu/hr, is subject to this subpart. While the boiler is subject to Subpart Dc, the PM and SO_2 emission standards under Subpart Dc are not applicable because boiler will only burn natural gas. Subpart Dc does not include NO_X emission standards. Alabama Power will comply with all the applicable monitoring, recordkeeping and reporting requirements under Subpart Dc.

4.4.4 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels

As part of the proposed Project, the new facility will have storage tanks which will hold ultra-low sulfur diesel (ULSD) used in the emergency generators and the fire water pump engine. 40 CFR Part 60, Subpart Kb regulates storage vessels with a capacity greater than 75 cubic meters (m^3) (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Also, Subpart Kb does not apply to storage vessels storing a liquid with a maximum true vapor pressure less than 0.5 psia. Subpart Kb will not apply to the proposed storage tanks because the capacity of each tank is less than 75 m^3, and because the maximum true vapor pressure of the stored liquid (ULSD) will be less than 0.02 psia, well below the 0.5 psia Subpart Kb applicability criteria.

4.4.5 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The diesel-fired emergency generators and diesel-fired fire water pump engine are subject to 40 CFR Part 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Alabama Power will comply with the emission standards by purchasing an engine certified by the manufacturer to the emission standards in 40 CFR 60.4202(a)(2), as applicable, for the same model year and maximum engine power. Alabama Power will also comply with all applicable Subpart IIII monitoring, recordkeeping and reporting requirements.

4.4.6 Subpart KKKK – Standards of Performance for Stationary Combustion Turbine Emissions

40 CFR Part 60, Subpart KKKK establishes NO_X and SO_2 emission limits for stationary combustion turbines that commence construction, modification, or reconstruction after February 18, 2005 and have a heat input at peak load equal to or greater than 10 MMBtu/hr based on the higher heating value.

Only the heat input rate to the combustion turbine is to be included when determining whether this NSPS is applicable to the proposed CC units. Any additional heat input to the associated HRSGs or duct burners, if applicable, should not be included when determining the peak heat input. However, if applicable to the turbines, the NSPS does apply to emissions from any associated HRSGs and duct burners.

The maximum heat input rate of each of the proposed turbines will exceed 3,000 MMBtu/hr, thus these new CC units will be subject to NO_X and SO_2 emission limits in this regulation.

4.4.6.1 Emission Limits for NO_X

Under Subpart KKKK, the proposed CC units are subject to a NO_X emission standard of 15 ppm at 15 percent O_2 or 0.43 lb/MWh. When operating at partial load (less than 75 percent of peak load) or at ambient temperatures less than 0°F, a NO_X limit of 96 ppm at 15 percent O_2 or 4.7 lb/MWh will apply to the units. Compliance is based on the arithmetic average of all hourly applicable NO_X emission limits and emission rates for the most recent 30-unit operating days. Because the HRSGs will not operate independently of the turbines, the separate NO_X emission standard for heat recovery units listed in Table 1 of Subpart KKKK will not be applicable to the Project.

As discussed in the BACT analysis in Section 5.0, the proposed controls on the CC units will reduce NO_X emissions to 2 ppmvd at 15 percent O_2 using low-NO_X combustors and SCR. Therefore, compliance with the above NO_X emission limits will be achieved. Compliance with the Subpart KKKK emission standards will be verified based on CEMS data.

4.4.6.2 Emission Limits for SO_2

The proposed CC units will be either subject to an emission limit of 0.9 lb/MWh gross output or the units must not burn any fuel which contains the total potential sulfur emissions in excess of 0.06 lb SO_2/MMBtu heat input.

Alabama Power will comply with the input-based emission standard for SO_2 by utilizing natural gas in the proposed CC units with a sulfur content lower than that needed to meet the 0.06 lb SO_2/MMBtu limit.

4.4.7 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions from Electric Utility Generating Units

40 CFR Part 60, Subpart TTTT was promulgated on October 23, 2015. It is applicable to each electric utility generating unit with a heat input greater than 250 MMBtu/hr of fossil fuel and that serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system, that commences construction on or after January 8, 2014 (or commenced reconstruction after January 18, 2014). As such, Subpart TTTT is applicable to the proposed CC units. An emission limit of 1,000 lb CO_2/MWh on a gross output basis over a rolling 12-month operating period, is applicable to the units. The proposed units will operate below 1,000 lb CO_2/MWh on a gross output basis. Therefore, the project will comply with the emission standard. In addition, Alabama Power will comply with all applicable monitoring, recordkeeping, reporting, and performance test requirements under Subpart TTTT.

4.4.8 Non-Applicability of All Other NSPS

NSPSs are developed for particular industrial source categories. The applicability of a particular NSPS to the proposed project can be readily ascertained based on the industrial source category covered. Apart from the specific standards delineated above, all other NSPSs are not applicable to the proposed project.

4.5 40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

The proposed Project is not subject to any of the 40 CFR Part 61 NESHAPs.

4.6 40 CFR Part 63 NESHAPs

A major source of hazardous air pollutants (HAPs) is any stationary source that has the potential to emit 10 tpy or more of a single HAP or 25 tpy of combined HAPs. 40 CFR Part 63 Maximum Achievable Control Technology (MACT) standards have been promulgated for major sources and, in a few cases, for area sources. Plant Barry is an existing major source of HAPs, and the Project will be subject to the provisions of several subparts of 40 CFR Part 63.

ADEM has incorporated by reference these rules under ADEM Admin Code r. 335-3-11.

4.6.1 Subpart A – General Provisions

40 CFR Part 63, Subpart A contains national emissions standards for HAPs defined in Section 112(b) of the Clean Air Act. All affected sources which are subject to a MACT standard under 40 CFR Part 63 are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source-specific NESHAP.

4.6.2 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

The Combustion Turbine MACT standard (Subpart YYYY) applies to stationary combustion turbines at major sources of HAP. Therefore, Subpart YYYY will potentially apply to the combustion turbines proposed as part of the Project. Per 40 CFR 63.6092, duct burners and HRSGs are considered steam generating units and are not covered under Subpart YYYY.

On August 18, 2004, EPA issued a stay on the effectiveness of the Subpart YYYY requirements pertaining to new lean premix gas-fired combustion turbines and new diffusion flame gas-fired turbines. The proposed new CC units will be classified as lean premix gas-fired combustion turbines because they are each equipped with lean premix technology. Thus, the new units are covered by the stay of Subpart YYYY requirements at 40 CFR 63.6095(d).

On January 31, 2020 EPA finalized amendments to Subpart YYYY to incorporate the results of the Residual Risk and Technology Review that was completed for the Stationary Combustion Turbine source category. EPA determined that the risks from this source category due to emissions of air toxics were acceptable and that the existing standard provides an ample margin of safety to protect public health. EPA also identified no new cost-effective controls under the technology review that would achieve further emissions reductions from the source category. EPA originally proposed to lift the administrative stay of the effectiveness of the standards but did not finalize that action to allow for additional time to review public comments as well as a petition to delist the source category. If the stay is removed in any subsequent action, the new CC units would become subject to a formaldehyde emission limit of 91 ppbvd @15% O_2.

Until the stay is lifted, however, per 40 CFR 63.6095(d), gas-fired combustion turbines are only required to comply with the initial notification requirements in 40 CFR 63.6145. Alabama Power will comply with the requirements of this subpart.

4.6.3 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The emergency generators and the fire water pump engine are subject to 40 CFR Part 63, Subpart ZZZZ and shall comply with the applicable requirements of this subpart by complying with the applicable requirements in 40 CFR Part 60 Subpart IIII. In addition, the emergency generators must meet the initial notification requirements specified in 63.6645(f).

4.6.4 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

The Major Source Industrial Boiler MACT standard (40 CFR Part 63, Subpart DDDDD), finalized on January 31, 2013 applies to boilers and process heaters located at major sources of HAP. The rule defines a boiler as an enclosed device using controlled combustion to recover thermal energy in the form of steam and/or hot water. The turbines do not meet this definition and are therefore not subject to this subpart. The definition of "boilers" under this subpart specifically excludes waste heat boilers; therefore, the duct burners are not subject to this subpart.

The 90.5 MMBtu/hr, natural gas fired auxiliary boiler is subject to Subpart DDDDD. It qualifies as a "Gas 1" unit under this rule. Gas 1 subcategory includes any boiler or process heater that burns only natural gas or refinery gas and burns liquid fuel only during periods of gas curtailment or gas supply emergencies or for periodic testing (testing - not to exceed 48 hours during any calendar year).

Per 40 CFR 63.7500(e), natural gas fired boilers (i.e., Gas 1 subcategory units) are not subject to the emission limits or the operating limits under this subpart but are subject to a tune-up. Per 40 CFR 63.7540, if a unit in the Gas 1 subcategory is equipped with an oxygen trim system, a tune-up of the unit is required to be conducted once every 5 years. Units not equipped with an oxygen trim system are subject to an annual tune-up requirement.

4.6.5 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

The Area Source Industrial Boiler MACT standard (40 CFR Part 63, Subpart JJJJJJ) does not apply to boilers or process heaters at major sources of HAPs (See Subpart DDDDD discussion above) and thus there are no units in the proposed Project that are subject to these requirements.

4.6.6 Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

The Mercury and Air Toxics (MATS) rule, 40 CFR Part 63, Subpart UUUUU, was promulgated on February 16, 2012. The MATS rule regulates emissions of heavy metals and acid gases from affected emission units. Per 40 CFR 63.9983(e), the rule does not apply to the electric generating units proposed as part of this Project because they will only burn natural gas. Also, any unit designated as a major source stationary combustion turbine subject to 40 CFR Part 63, Subpart YYYY is not subject to Subpart UUUUU. Therefore, Subpart UUUUU does not apply to the CC units.

4.7 Acid Rain Program

The proposed CC units are fossil fuel-fired combustion devices used to generate electricity for sale, and their capacity serves generators that exceed 25 MW. Therefore, the proposed units meet the definition of an affected Phase II "utility unit" under the Acid Rain Program (ARP) pursuant to Title IV of the 1990 CAA Amendments (40 CFR 72.6). Plant Barry already has an existing Phase II Acid Rain Permit.

The primary applicable requirements under the ARP include:

- Amend the Phase II Acid Rain Permit to include the new utility units;
- Install CEMS on the proposed CC units to demonstrate compliance with the ARP provisions meeting the requirements specified in 40 CFR Part 75; and

- Hold allowances equivalent to annual SO_2 emissions.

An Acid Rain permit application must be submitted 24 months before the units commence commercial operation and include the deadline for monitoring certification (90 days after commencement of commercial operation). The Acid Rain permit application will be submitted as required.

The Alabama Power will operate in compliance with applicable provisions of the Title IV Acid Rain rules as adopted by reference under ADEM Admin. Code r. 335-3-18. Alabama Power will meet the applicable Acid Rain requirements that become effective after the issuance of the Acid Rain permit and will include the new CC units in its Title IV Acid Rain monitoring plan, as required under 40 CFR Part 72.

4.8 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) regulations are codified in 40 CFR Part 64. The CAM Rule applies to pollutant-specific emissions units (PSEU) that:

1) are subject to an emission limit or standard, other than an emission limitation or standard:
    a. established after November 15, 1990 pursuant to section 111 or 112 of the Act;
    b. establishing Stratospheric ozone protection requirements under title VI of the Act;
    c. establishing Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act;
    d. that applies solely under an emissions trading program approved by the Administrator under the Act;
    e. that imposes an emissions cap that meets the requirements specified in 70.4(b)(12) or 71.6(a)(13)(iii); and
    f. for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 64.1.
2) use a control device to achieve compliance with that emission limit or standard, and
3) have potential pre-control device emissions in the amount required to classify the unit as a major source under Part 70 of the Clean Air Act (CAA) (i.e., 100 tons/year).

The CC units will be subject to the NOx emission limit outlined in 40 CFR Part 60 Subpart KKKK, the proposed NOx BACT limit, and the 4 ppm at 15 percent O_2 State NOx emission limit under ADEM Admin. Code r. 335-3-8-06(3). The CC units will utilize SCR systems to comply with these emission limits, and the pre-control rate of NOx emissions from each CC unit is in excess of 100 tons/year. However, CAM does not apply to emission limits established pursuant to section 111 of the Act and thus will not apply to the 40 CFR Part 60 Subpart KKKK NOx emission limit but will apply to the State NOx emission limit of 4 ppm at 15 percent O_2 and to the proposed NOx BACT limit. 40 CFR Part 60 Subpart KKKK requires each CC unit to be equipped with a NOx CEMS in order to monitor compliance with the NSPS limit. Alabama Power is proposing to utilize the NOx CEMS as a CAM indicator to provide reasonable assurance of continuous compliance with both the State NOx limit and the proposed NOx BACT limit.

No other emission units proposed to be installed as part of this Project have active emission control devices; therefore, no other CAM requirements apply.

4.9 Risk Management Program (RMP), Section 112(r)

Title III of the 1990 CAA Amendments contains requirements for subject facilities that store and/or process certain hazardous substances for ensuring their safe use. Under these requirements,

facilities must identify and assess their hazards and carry out certain activities designed to reduce the likelihood and severity of accidental chemical releases. Section 112(r) of the CAA, codified in 40 CFR Part 68, mandates the EPA to publish rules to develop and implement a program for sources with more than the threshold quantity of a listed regulated substance to identify, prevent, and minimize the consequences of accidental releases. The three elements that should be incorporated into an RMP include:

- Hazard Assessment;
- Prevention Program; and
- Emergency Response Program.

The existing Plant Barry facility currently stores anhydrous ammonia above the threshold quantity for use in the SCR and has a Risk Management Program in place. Alabama Power will update Plant Barry 's RMP to account for the increased amount of anhydrous ammonia stored on site due to the Project's SCR.

4.10 Cross-State Air Pollution Rule

On July 6, 2011 the EPA promulgated the Cross-State Air Pollution Rule (CSAPR). CSAPR applicability and requirements are codified at 40 CFR 97, ADEM Admin Code r. 335-3-5.06 through 335-3-5-.36, and ADEM Admin. Code r. 335-3-8-.07 through .70. CSAPR requires states to address interstate transport of SO_2 and NO_x emissions that affect downwind states' ability to attain and maintain ozone and $PM_{2.5}$ NAAQS.

Alabama Power will hold enough allowances to cover emissions and comply with the permitting, monitoring, recordkeeping and reporting requirements set forth by CSAPR, including the installation and certification of continuous emission monitors.

4.11 Greenhouse Gas Reporting Program

The Greenhous Gas Reporting Program (GHGRP), codified in 40 CFR Part 98, requires facilities belonging to certain source categories to report their annual GHG emissions to EPA. Included on EPA's list of affected source categories are electric generating units that report CO_2 mass emissions year-round through 40 CFR Part 75. Such affected facilities must report their annual GHG emissions from not only the electric generating unit, but from all stationary fuel combustion sources (excluding emergency equipment) located at the facility. Thus, the CC units and the auxiliary boiler will be subject to 40 CFR Part 98 and Alabama Power will report to EPA the Project's annual GHG emissions as applicable.

4.12 Other Applicable Alabama Rules and Regulations

As previously mentioned, ADEM has adopted or incorporated by reference many of the federal regulations into the State Implementation Plan (SIP), that has been approved by EPA, under ADEM Code r. 335-3. Other applicable state regulations not previously mentioned are discussed below.

4.12.1 ADEM Admin. Code r. 335-3-4-.01 – Visible Emissions

ADEM Admin. Code r. 335-3-4-.01 restricts visible emissions from sources to 20% with no more than one six-minute period of up to 40% opacity per 60-minute period. The proposed emission units are subject to this regulation and will comply with the applicable requirements.

4.12.2 ADEM Admin. Code r. 335-3-4-.02 – Fugitive Dust and Emissions

This regulation applies to sources which have the potential to cause fugitive dust to become airborne. Plant Barry will continue to comply with ADEM's fugitive dust requirements as specified in the General Permit Provisos of its Title V Major Source Operating Permit.

4.12.3 ADEM Admin. Code r. 335-3-4-.03 –Fuel Burning Equipment

ADEM Admin. Code r. 335-3-4-.03 regulates particulate emissions (PM) from fuel burning equipment. As defined in ADEM Admin Code r. 335-3-1-.02(ee), fuel burning equipment is:

"…any equipment, device, or contrivance and all appurtenances thereto, including ducts, breechings, fuel-feeding equipment, ash removal equipment, combustion controls, stacks, and chimney, used primarily, but not exclusively, to burn any fuel for the purpose of indirect heating in which the material being heated is not contacted by and adds no substance to the products of combustion."

The CC units, the auxiliary boiler, the emergency generator engines and the fire water pump engine all qualify as fuel burning equipment in a Class 1 County and are subject to PM emission limits based on the heat input of the source. These emission limits are presented in Table 4-6 for the fuel burning equipment proposed as part of this Project. The emission estimates for these units are below the allowable emission limits; therefore, compliance with the PM emission standards is expected to be achieved.

Table 4-6: Particulate Matter Emission Limits for Fuel Burning Equipment

Emission Unit	Rated Heat Input (MMBtu/hr)	ADEM Admin. Code r. 335-3-4-.03 Allowable Emissions (lb/MMBtu)
Two CC Units	4,883 (per unit)	0.12
Auxiliary Boiler	90.5	0.19
Two Emergency Engines	17.47 (per engine)	0.392
Fire water Pump	2.07	1.0

4.12.4 ADEM Admin. Code r. 335-3-4-.04 – PM from Process Industries

This requirement limits emissions of PM from general manufacturing processes and other operations at industrial facilities. This regulation applies to the Project's proposed cooling towers.

4.12.5 ADEM Admin. Code r. 335-3-5-.01 – SO_2 from Fuel Combustion

This regulation limits SO_2 emissions from fuel combustion units in Category I and Category II counties. Mobile County (the location of Plant Barry) is a Category I county and therefore, emissions of sulfur oxides (as SO_2) from the fuel combustion units are required to be limited to 1.8 lb/MMBtu. The fuel combustion units will either burn natural gas or ULSD. The estimated emissions for the CC units, auxiliary boiler, emergency generators, and fire water pump engines are below the emission limit, therefore compliance with the emission limit is expected to be achieved.

4.12.6 ADEM Admin. Code r. 335-3-8 – Nitrogen Oxide Emissions

ADEM Admin. Code r. 335-3-8-.06 applies to all new combined-cycle electric generating units that commence operation on or after April 1, 2003. The rule limits the emissions of nitrogen oxides from combined-cycle units firing natural gas to 4.0 ppmvd at 15 percent O_2. Compliance with the NOx emissions limitation is expected to be achieved.

4.12.7 ADEM Admin. Code r. 335-3-14 – Air Permits

Alabama Power evaluated the Project's PSD applicability and determined that PSD review is triggered for NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, CO, SO_2, and GHG. ADEM Admin. Code r. 335-3-14-.04 (PSD Permitting) applies to the Project and requires that a PSD permit be obtained prior to commencing construction of the Project emission sources. This document serves as the application for issuance of a PSD permit for the Project.

4.12.8 ADEM Admin. Code r. 335-3-16 – Major Source Operating Permits

Plant Barry currently operates under a Major Source Operating Permit (MSOP) (Facility Number 503-1001) and will remain a major source post-Project. Alabama Power will be required to submit an application to incorporate the PSD construction permit into its current MSOP within 12 months of commencing operation of the proposed Project sources.

5.0 Control Technology Review

5.1 Technical Approach

5.1.1 Overview

ADEM's PSD regulations (ADEM Admin Code r. 335-3-14-.04 (9)(c)) require a Best Available Control Technology (BACT) analysis for each new major source or major modification at an existing major source for which a significant net emissions increase of a NSR regulated pollutant will occur. As described in Section 3 of this application, the emissions increases associated with the Project are sufficient to trigger PSD review for PM, PM10, and PM2.5, NOx, CO, VOC, SO_2, and GHG (as CO_2e).

BACT is defined in ADEM Admin Code r. 335-3-14-.04 (2)(l) as:

> *... an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, 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 BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR 60 and 61. If the Director determines that 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 BACT. Such standard shall, to the degree possible, set forth 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.*

Guidelines for the evaluation of BACT can be found in EPA's Guidance for Determining BACT Under PSD[3] and in the Draft New Source Review Workshop Manual[4]. These guidelines were drafted by the EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is determined on a case-by-case basis. To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans[5]. Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the

---

[3] Memo from David G. Hawkins, EPA Headquarters, on Guidance for Determining BACT under PSD to EPA Reg'l Adm'rs (Jan. 4, 1979) (on file with the U.S. EPA).

[4] EPA, *Draft New Source Review Workshop Manual* (Oct. 1990).

[5] Memo from J. Craig Potter, EPA Headquarters, on Improving New Source Review Implementation to EPA Reg'l Adm'rs (Dec. 1, 1987) (on file with the U.S. EPA).

permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals:

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[6]

U.S EPA has reached similar conclusions in prior determinations for PSD permits.

> *"Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term."*[7]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. Accordingly, while viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in U.S. EPA use to develop MACT standards over a period of several years and is far beyond what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."

When evaluating BACT, published emission limits for similar source types must be used with care in assessing what is "achievable." Limits established for facilities that were never built are inherently unreliable indicators, as they have never been demonstrated and the permittee never assumed a significant liability in having to meet such limits. For similar reasons, permitted units that have not yet commenced construction must also be viewed with care.

A control technology must be "available" to be considered in a BACT determination. This means that the technology has progressed beyond the conceptual stage and pilot testing phase and must have

---

[6] *Sierra Club v. E.P.A.,* 167 F.3d 658, 665 (D.C. Cir. 1999).

[7] *In re Newmont Nevada Energy Inv., LLC, TS Power Plant*, 2005 WL 4905114, at *13 (Dec. 21, 2005).

been demonstrated successfully on full-scale operations for a sufficient period. Theoretical, experimental, or developing technologies are not “available” under BACT. A control technology is neither demonstrated nor available if government subsidies are required to fund evaluations of the technology. In many cases, a technology is not “available” for all sizes of a unit. A control technology must also be “commercially available.” This means that the technology must be offered for sale through commercial channels with commercial terms.

The source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source. EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives.

5.1.2 BACT Assessment Methodology

The following sections describe the five steps of the top-down approach and provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the proposed new emission units at Plant Barry.

Step 1

The first step is to define the spectrum of process and/or add-on control alternatives potentially applicable to the subject emissions unit. The following categories of technologies are addressed in identifying candidate control alternatives:

- Demonstrated add-on control technologies applied to the same emissions unit at other similar source types;
- Add-on controls not demonstrated for the source category in question but transferred from other source categories with similar emission stream characteristics;
- Combustion controls;
- Add-on control devices serving multiple emission units in parallel; and
- Equipment or work practices, especially for fugitive or area emission sources where add-on controls are not feasible.

There is no specific methodology that is required to be used to identify all available emission control technologies and levels for a given source or pollutant. The most comprehensive source of this information, however, is EPA’s RACT/BACT/LAER Clearinghouse (RBLC). This searchable database of emission control technology determinations is maintained by EPA, and as such is generally the starting point for developing the required ranking of emission control technologies and levels.

Step 2

The second step is to evaluate the technical feasibility of the alternatives identified in the first step and to reject those that can be demonstrated as technically infeasible based on an engineering evaluation or on chemical or physical principles. The following criteria were considered in determining technical feasibility: previous commercial-scale demonstrations, precedents based on issued PSD permits, state requirements for similar sources, technology transfer, and engineering evaluations for the control devices or work practice standards considered.

Step 3

The third step involves ranking each technically feasible alternative in decreasing order of overall emissions control effectiveness considering the specific operating constraints of the emission unit in question. After determining what control efficiency is achievable with each technically feasible control alternative, the alternatives are ranked into a control hierarchy from most to least stringent. Typically, the Step 3 ranking presents an array of control technology alternatives that includes the following types of information:

- Control efficiencies (% pollutant removed or controlled),
- Expected emission rate (ton/year, pounds/hour)
- Expected emission reduction (tons/year)
- Economic impacts (cost effectiveness), and
- Adverse environmental and energy impacts.

However, an applicant proposing the top level of control as BACT need not provide cost and other detailed information regarding other control options.

Step 4

The fourth step consists of an objective evaluation of the energy, environmental, and economic impacts to arrive at a control technology or level of control that is representative of BACT. The economic evaluation is carried out using procedures recommended by the EPA's Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual[8]. The economic evaluation looks at the annualized control cost (in dollars per ton of emissions removed) for a particular control technology or level on the source under consideration in comparison to commonly accepted values for cost effective emission controls established by the state regulatory agency. As noted above, this is a site-specific evaluation and the fact that a particular technology or level of emissions control has been concluded to be representative of BACT at another facility does not mean that the same technology or level constitutes BACT for the proposed new emission units at Plant Barry.

If the top level of control is determined to be economically infeasible based on high cost effectiveness, or to cause adverse energy or environmental impacts, the control technology is rejected as BACT and the impact analysis is performed on the next most stringent control alternative until the technology or emissions level under consideration cannot be eliminated by any source-specific adverse environmental, energy, or economic impacts.

Step 5

The final step is to summarize the selection of BACT and propose the associated emission limits or work practices to be incorporated into the permit plus any recommended recordkeeping and monitoring conditions that should be incorporated into the final permit.

[8] EPA, *EPA Air Pollution Control Cost Manual*, at Sec. 1, Ch. 2 (7th ed. 2018).

5.2 BACT for Combined Cycle Units

5.2.1 BACT for Nitrogen Oxides Emissions

5.2.1.1 Formation

NO_x emissions are formed in combustion sources in three ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NOx), 2) the oxidation of nitrogen contained in the fuel (fuel NOx), and 3) the reaction of molecular nitrogen with certain free radical compounds (e.g., CN, NH_2) that are typically present in the fuel-rich zones of a combustion flame. Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen, and at typical combustor conditions, the contribution of prompt NOx formation is relatively small. Therefore, the most predominant formation mechanism for NOx emissions from natural gas fired combined cycle units is thermal NOx. The rate of formation of thermal NOx is a function of residence time and free oxygen concentration; it increases exponentially with increasing peak flame temperature.

“Front end” NOx control techniques are aimed at controlling thermal NOx and/or fuel NOx. The primary front-end combustion controls for combustion turbine systems include water or steam injection into the combustor, and specific combustor design features. The addition of an inert diluent such as water or steam into the high temperature region of the combustor decreases NOx formation by quenching peak flame temperature. Dry low-NOx combustors limit peak flame temperature and excess oxygen with lean, pre-mix flames that decrease NOx formation to levels that are equal or better than achieved via water or steam injection when burning natural gas.

Other control methods, known as “back-end” or post combustion controls and described in greater detail in the following subsections, remove NOx from the exhaust gas stream once it has been formed.

5.2.1.2 Step 1 - Available NOx Control Alternatives

Available control technologies to reduce NOx emissions include a selective catalytic reduction (SCR) system, dry low NOx combustors, and water or steam injection which are each discussed in the following sections.

Selective Catalytic Reduction (SCR)

SCR is a process which involves post combustion removal of NOx from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \qquad (1)$$

$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O \qquad (2)$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \qquad (3)$$

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H2O \qquad (4)$$

$$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O \qquad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reactions. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling," design of the NH_3 injection system, and high NH_3 slip.

For most SCR catalyst formulations, the NOx reduction reactions take place within the temperature range of 650 to 850°F. For combined-cycle units, the catalyst grid is installed within the heat recovery steam generator at a location where the combustion turbine exhaust temperature has been reduced by the steam generating banks to within this range. SCR catalyst materials lose activity over time, necessitating catalyst cleaning or replacement. In natural gas-fired applications, expected SCR catalyst life is within the range of 32,000 to 80,000 operating hours.[9]

Dry Low NOx Combustors

Combustion control techniques that utilize design and/or operational features of the turbine's combustors which reduce NOx emissions without injecting an inert diluent (water or steam) are generically referred to as "dry" Low NOx (DLN) measures. The design features of a DLN combustor design are vendor-specific, but generally DLN combustors seek to reduce thermal NOx formation by controlling peak combustion temperature, combustion zone residence time, and combustion zone free oxygen concentration. Alternatives include combustion distribution over several burner stages and pre-mixing air and fuel prior to injection into the combustion zone. These measures produce a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

DLN combustors have been employed successfully on natural gas-fired combustion turbines for more than fifteen years.

Water or Steam Injection

Water or steam injection as a NOx control alternative was concluded to represent the Best Demonstrated Technology (BDT) for control of NOx emissions from stationary combustion turbines when the original NSPS for this source category was promulgated in 1977[10]. It involves the injection of water or steam into the high temperature region of the combustor flame. Thermal NOx formation is minimized with this alternative because peak combustion temperature, combustion zone residence time, and combustion zone free oxygen are all reduced.

5.2.1.3 Steps 2-3 - Technical Feasibility Assessment and Ranking of NOx Control Alternatives

A search of EPA's RBLC was carried out to identify NOx BACT determinations for large natural gas-fired combined-cycle units permitted since 2008. The results of this RBLC search are summarized in Appendix E, Table E-1.

Among the combined-cycle unit listings in the RBLC that met these criteria, 165 of the 177 natural gas-fired listings describe the use of SCR either alone or in conjunction with DLN combustors or water

[9] EPA Air Pollution Control Cost Manual, Section 4 Chapter 2 "Selective Catalytic Reduction" (June 2019)

[10] 42 Fed. Reg. 53,782, 53,785 (Oct. 3, 1977).

injection as BACT. Consequently, the use of SCR and DLN is considered a technically feasible alternative for control of NOx emissions from natural gas-fired combined cycle units.

The top-level control of NOx emissions for natural gas-fired combined-cycle units is the use of DLN combustors to minimize NOx formation in conjunction with the use of SCR, followed by the use of DLN or water injection alone. Good combustion practices would represent the lowest level of NOx control for this source type.

For continuous operation, the RBLC limits for combined cycle units using SCR and DLN range from 2 to 5 ppmvd @15% O_2.

5.2.1.4 Step 4 – NOx Control Effectiveness Evaluation

Economic and Energy Impacts

There are economic and energy impacts associated with the use of SCR and DLN combustors on combined cycle units, but these impacts are not considered to be material to disqualify this alternative as a BACT candidate. There are no impacts associated with good combustion practices.

Environmental Impacts

In applications employing SCR, an excess of ammonia must be injected into the turbine exhaust in order to minimize NOx emission rates. This creates two forms of adverse environmental impacts. Ammonia that is not consumed in the SCR system is discharged to the atmosphere as ammonia slip, and excess ammonia can react with SO_2 and SO_3 in the turbine exhaust to form ammonium salt compounds (ammonium sulfate and ammonium bisulfate) which can foul downstream heat transfer equipment and subsequently be discharged as particulate matter. In addition, the use of an SCR can increase the formation of sulfuric acid emissions by oxidizing a portion of the turbine's SO_2 emissions to SO_3 which subsequently reacts with water vapor to form sulfuric acid. Also, the catalyst must periodically be regenerated and must be disposed of or recycled at the end of its useful life. However, the increase in sulfuric acid emissions is generally insignificant in natural gas-fired combustion turbines, and the additional waste generated as a result of catalyst disposal is not considered to be material to the proposed combined cycle units.

There are no environmental impacts associated with DLN combustors or good combustion practices.

5.2.1.5 Step 5 - Evaluation of BACT for NOx Control

The new combined cycle units propose to employ SCR and DLN combustors which are the most stringent alternative for control of NOx emissions and are considered representative of BACT for this source type. During normal operating conditions, the proposed combined cycle units are guaranteed to meet a NOx emissions level of 2 ppmvd @15% O_2 with a maximum emission rate of 39.1 lb/hr for each unit. The emission level is consistent with the emission rates in the RBLC for this source type. As such, the NOx emission rate of 39.1 lb/hr is proposed as BACT for each combined-cycle unit during periods of normal operation.

5.2.2 BACT for Carbon Monoxide Emissions

5.2.2.1 Formation

CO emissions are generated during combustion as a result of incomplete conversion of carbon-containing compounds to CO_2 and water during fuel combustion. CO emission rates are principally

influenced by equipment operating conditions. Higher CO emissions may be the result of lower than optimal combustion temperature, insufficient combustor residence time, and lower operating loads.

5.2.2.2 Step 1 - Available CO Control Alternatives

Available control technologies to reduce CO emissions include an oxidation catalyst and good combustion practices which are each discussed in the following sections.

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after it is formed in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the turbine exhaust, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Oxidation of CO to CO_2 utilizes the excess oxygen present in the turbine exhaust; the activation energy required for the oxidation reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of particulate matter and sulfuric acid mist.

CO catalytic oxidation systems operate in a relatively narrow temperature range. At lower temperatures, CO conversion efficiency falls off rapidly. At higher temperatures, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is placed within the HRSG at a location that is selected to ensure that the proper operating temperature is maintained, considering the temperature variations that are expected to occur across the unit's operating load range.

Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation to minimize CO emissions.

Combustion Controls/Good Combustion Practices

As noted above, CO is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing and operating the combustion system to maximize oxidation of the fuel carbon to CO_2. Proper combustor design and optimization of the combustion air feed systems to achieve good combustion efficiency will minimize the generation of CO emissions from combustion turbines.

5.2.2.3 Step 2 – Technical Feasibility Assessment of CO Control Alternatives

A search of EPA's RBLC was performed to identify large natural gas-fired combined-cycle combustion units (i.e., those with an electrical output greater than 25 MW) permitted since 2008 with BACT determinations for CO. The RBLC search found a total of 174 combined-cycle natural gas-fired unit listings meeting these criteria with emission limitations for CO; 165 of these listings describe the CO emissions control technology that is employed. The RBLC search results are summarized in Appendix E, Table E-2.

Of the 165 natural gas-fired combined-cycle unit listings in the RBLC with outputs greater than 25 MW permitted since 2008 that describe the CO emissions control technology employed, 143 listings describe the use of an oxidation catalyst system as BACT. Accordingly, such systems are considered

a technically feasible alternative for new CC units like the units described in this application. The RBLC search results found that combustion controls alone (including combustor design or good combustion practices) were concluded to be representative of BACT for a total of 14 of the 165 natural gas-fired RBLC entries where the emission control technology was identified.

Accordingly, an oxidation catalyst and combustion controls are considered to be technically feasible CO emissions control alternatives for the proposed combined cycle units.

5.2.2.4 Step 3 - Ranking of Available CO Control Alternatives

Based on the RBLC search conducted, the use of an oxidation catalyst system is considered the top-level CO emissions control alternative for natural gas-fired combined-cycle units. The listings in the RBLC with the lowest emission limits are described as employing oxidation catalyst systems. Emission limits for units employing oxidation catalyst range from 0.9 to 51 ppm. Some of the RBLC listings do not clearly identify whether the emission limits are for the turbine alone or for the turbine and duct burner together.

Combustion controls are the next level of CO emissions control below the use of an oxidation catalyst system. Emission limits for combined cycle units listed as employing combustion controls range from 4 ppm to 50 ppm.

5.2.2.5 Step 4 – CO Control Effectiveness Evaluation

Energy and Economic Impacts

An oxidation catalyst system does provide a negative impact on unit performance related to the backpressure that the system imposes, which impacts the unit's efficiency and results in an economic impact associated with the use of such systems on combined-cycle units. However, neither the energy nor the economic impacts associated with operating oxidation catalyst systems are considered material to the proposed combined-cycle units. There are no energy or economic impacts associated with the use of combustion controls.

Environmental Impacts

The use of an oxidation catalyst system on combined cycle units has been shown to increase sulfuric acid emissions as a result of oxidation of a portion of the unit's SO_2 emissions to SO_3 which then reacts with water vapor to form sulfuric acid. The catalyst must also be regenerated periodically and must be disposed of or recycled at the end of its useful life. However, the increase in sulfuric acid emissions and the additional waste generated as a result of catalyst disposal are not considered to be material to the proposed combined cycle units.

There are no environmental impacts associated with the use of combustion controls on combined cycle units.

5.2.2.6 Step 5 - Evaluation of BACT for CO Control

The use of oxidation catalyst systems is technically feasible on the proposed combined cycle units, and their use does not result in any material economic, energy, or environmental impacts. Therefore, the use of oxidation catalyst systems to control CO emissions is considered representative of BACT for these combined-cycle units. During normal operating conditions, the proposed combined cycle units are guaranteed to meet a CO emission level of 2 ppmvd @15% O_2, which results in a maximum emission rate of 23.8 lb/hr for each unit. The vendor guaranteed emission level of 2 ppmvd @15% O_2

is representative of BACT for similar units. Therefore, a CO emission rate of 23.8 lb/hr is proposed as the BACT limit for each combined cycle unit during periods of normal operation.

5.2.3 BACT for Volatile Organic Compound (VOC) Emissions

5.2.3.1 Formation

VOC emissions from combined cycle units are impacted by the same factors that impact CO emissions as described in Section 5.2.2.1 above. VOC emissions result from incomplete combustion of carbon compounds in the fuel, which is influenced primarily by the temperature and residence time within the combustion zone.

5.2.3.2 Step 1 - Available VOC Control Alternatives

Available control technologies to reduce VOC emissions from combined cycle units include oxidation catalyst and combustion controls/good combustion practices.

Oxidation Catalyst

As described above in Section 5.2.2.2, an oxidation catalyst is a post-combustion technology that oxidizes products of incomplete combustion in the turbine exhaust. As with CO, VOC compounds will react with residual oxygen in the presence of a catalyst, producing carbon dioxide and water vapor. The performance of an oxidation catalyst system is dependent on the specific VOC constituents present in the turbine exhaust.

Good Combustion Practices

As previously discussed, VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing and operating the combustion system to maximize oxidation of the fuel carbon to CO_2. Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time within the turbine combustor will minimize the formation of VOCs.

5.2.3.3 Step 2 - Technical Feasibility Assessment of VOC Control Alternatives

A search of EPA's RBLC was performed to identify large natural gas-fired combined-cycle units permitted since 2008 with BACT determinations for VOC. This search identified a total of 137 listings of units in this category with BACT determinations for VOC; 121 of these listings describe the control technology that was concluded to be representative of BACT. The results of this RBLC search are summarized in Appendix E, Table E-3.

There are 103 large natural gas-fired combined-cycle unit listings in the RBLC permitted since 2008 that are described as using an oxidation catalyst system to control VOC emissions. A total of 64 listings identify combustor design or good combustion practices, either alone or in combination with the use of an oxidation catalyst system, as representative of BACT. Thus, oxidation catalyst and combustor design or good combustion practices are considered technically feasible alternatives for control of this pollutant for the proposed units.

5.2.3.4 Step 3 - Ranking of Available VOC Control Alternatives

The use of an oxidation catalyst system is considered the top-level VOC emissions control alternative for natural gas-fired combined-cycle units based on the RBLC search conducted. Emission limits for units employing an oxidation catalyst system range from 0.7 to 7 ppmvd @ 15% O_2. Some of the RBLC listings do not clearly identify whether the emission limits are for the turbine

alone or for the turbine and duct burner together. Combustion controls are the next level of emission control below the use of an oxidation catalyst system, although emission limits for units listed as employing combustion controls fall in the same emissions rate range.

5.2.3.5 Step 4 – VOC Control Effectiveness Evaluation

Economic and Energy Impacts

An oxidation catalyst system does provide a negative impact on unit performance related to the backpressure that the system imposes, which impacts the unit's efficiency and results in an economic impact associated with the use of such systems on combined-cycle units. However, neither the energy nor the economic impacts associated with operating oxidation catalyst systems are considered material to the proposed combined-cycle units.

There are no energy or economic impacts associated with the use of combustion controls on combined-cycle units.

Environmental Impacts

As described in Section 5.2.2.5, the use of an oxidation catalyst system on combined cycle units has been shown to increase sulfuric acid emissions as a result of oxidation of a portion of the unit's SO_2 emissions to SO_3 and the subsequent reaction of SO_3 with water vapor to form sulfuric acid. The catalyst must also be regenerated periodically and must be disposed of or recycled at the end of its useful life. However, the increase in sulfuric acid emissions and the additional waste generated as a result of catalyst disposal are not considered material to the proposed combined cycle units.

There are no environmental impacts associated with the use of combustion controls on combined cycle units.

5.2.3.6 Step 5 - Evaluation of BACT for VOC Control

As described in Section 5.2.2.6, the use of oxidation catalyst systems is technically feasible on the proposed combined cycle units. The use of an oxidation catalyst does not result in any material economic, energy, or environmental impacts, and consequently the use of oxidation catalyst systems to control VOC emissions is considered representative of BACT for these combined-cycle units. During normal operating conditions, the units are guaranteed to meet a VOC emission level of 2 ppmvd @15% O2, which results in a maximum emissions rate of 13.6 lb/hr (as methane) per combined cycle unit. Therefore, 13.6 lb/hr per unit is proposed as the VOC BACT limit for each unit during periods of normal operation.

5.2.4 BACT for Particulate Matter Emissions

5.2.4.1 Formation

Particulate matter emissions from combined cycle units are a combination of filterable (front-half) and condensable (back-half) particles. Filterable particulate matter is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate matter, which is aggregated with filterable particulate matter when quantifying PM10 and PM2.5 emission rates, is attributable primarily to the formation of sulfates and possibly organic compounds.

The following subsections present the BACT assessment for particulate matter emissions (including total PM, PM_{10}, and $PM_{2.5}$) from combined-cycle units.

5.2.4.2 Steps 1-4 – Availability, Technical Feasibility, and Ranking of PM, PM_{10} and $PM_{2.5}$ Control Alternatives

When the original NSPS for Stationary Gas Turbines (40 CFR 60, Subpart GG) was promulgated in 1979, EPA recognized that "particulate emissions from stationary gas turbines are minimal." The Agency noted that PM control devices are not typically installed on combustion turbines and that the cost of installing a PM control device on this source type is prohibitive.[11] As a consequence, performance standards for control of PM emissions from stationary combustion turbines were not proposed or promulgated as part of Subpart GG.

Similarly, when the updated NSPS for stationary combustion turbines (40 CFR 60, Subpart KKKK) was proposed in 2005, EPA declined to establish emission limits on PM for this source type because "…particulate matter emissions are negligible with natural gas firing due to the low sulfur content of natural gas. Emissions of PM are only marginally significant with distillate oil firing because of the lower ash content…"[12] Additionally, at that time EPA determined that no combustion turbines permitted since 2003 utilized add-on controls.

The top-level PM control method demonstrated for natural gas-fired combined cycle units is the use of low-ash and low-sulfur fuel (i.e., natural gas). Proper combustion control and the firing of fuels with negligible or zero ash content and low sulfur content is the only PM control method listed in any of the combined-cycle unit listings in the RBLC (see Appendix E, Table E-4).

Add-on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial natural gas-fired combined cycle units. The use of ESPs and baghouses are considered technically infeasible and do not represent an available control technology.

Proper combustion and the use of natural gas as fuel is considered technically feasible and the top level of particulate matter control for combined cycle units.

Per the data presented in EPA's RBLC, the typical emission rates determined to represent BACT for total PM (TPM) from natural gas-fired combined cycle units are in the range of 0.0026 to 0.012 lb/MMBtu (see Appendix E, Table E-4). However, it must be noted that a large degree of uncertainty exists with this range because the emission limits reported to the RBLC do not always clarify whether the emissions are filterable PM only or include filterable and condensable PM emissions. PM emissions vary with turbine make, model, heat input rate, sulfur content of natural gas, and post combustion control impacts to formation of condensable PM. Additionally, many of the RBLC listings do not describe the reported PM species (PM, PM_{10}, or $PM_{2.5}$), test method, or whether the emission rate has been achieved in practice.

5.2.4.3 Step 5 - Evaluation of BACT for PM Control

The use of good combustion practices and firing natural gas are concluded to be representative of BACT for PM emissions from combined-cycle units. PM emission rates from these units vary depending upon the manufacturer, turbine size, sulfur content of the fuel, and the resulting available vendor performance guarantees. During normal operating conditions, the proposed units will meet an emission limitation of 21.51 lb/hr for PM_{10} and $PM_{2.5}$ which includes both filterable and condensable

---

[11] 44 Fed. Reg. 52,792, 52,798 (Sept. 10, 1979); EPA, *Standards Support and Envtl. Impact Statement Volume 1: Proposed Standards of Performance for Stationary Gas Turbines*, at 8-6 (Sept. 1977).

[12] 70 Fed. Reg. 8,314, 8,321 (Feb. 18, 2005).

PM and is less than 0.005 lb/mmBtu. Therefore, the exclusive use of natural gas with an emissions limit of 21.51 lb/hr is proposed as the BACT limit for PM_{10} and for $PM_{2.5}$ emissions from the CC units.

5.2.5 BACT for Sulfur Dioxide Emissions

Emissions of SO_2 from combined cycle units occur as a result of the oxidation of sulfur-containing compounds in the fuel during the combustion process. SO_2 emissions associated with natural gas combustion are typically very low due to the low concentration of sulfur compounds in natural gas.

5.2.5.1 Steps 1 & 2 –Technical Feasibility Assessment for SO_2 Emission Control Alternatives

A search of EPA's RBLC was performed to identify large natural gas-fired combined-cycle units permitted since 2008 with BACT determinations for SO_2. This search identified a total of 49 listings of units in this category with BACT determinations for SO_2; all of these listings describe the use of natural gas or clean fuel as the control technology that was concluded to be representative of BACT. An additional 12 listings also list efficient combustion or GCP as representative of BACT. The results of this RBLC search are summarized in Appendix E, Table E-5.

Flue gas desulfurization (FGD) is a post-combustion alternative that has been utilized to control SO_2 emissions from certain combustion sources that utilize high sulfur-content fuels, including coal-fired and residual oil-fired boilers. EPA concluded that FGD use on these units would be unreasonable when emission standards for combustion turbines were initially proposed under the NSPS program. At that time, the Agency selected the firing of low sulfur fuels as the basis of the proposed standards of performance[13]. Similarly, the use of low sulfur fuel was proposed as the basis of the SO_2 emission standard in the most recent revision of the NSPS for combustion turbines[14]. FGD is not technically feasible on natural gas-fired combined cycle units because the SO_2 emissions from these sources are two orders of magnitude lower than the outlet emission rates that have been achieved on other combustion sources using FGD. Consequently, the only technically feasible and top-level alternative to control SO_2 emissions is the use of low sulfur fuels, including natural gas.

5.2.5.2 Steps 3-5 – Availability, Technical Feasibility, and Ranking of SO_2 Control Alternatives and Evaluation of BACT

As shown in Appendix E, Table E-5, the SO_2 emission rates from combined cycle units listed in EPA's RACT/BACT/LAER Clearinghouse vary from 0.0003 to 0.06 lb/MMBtu depending on the sulfur content of the fuel. Based on a natural gas sulfur content of 0.6 gr S/100 scf, the maximum SO_2 emission rate from the proposed combined cycle units will be 8.21 lb/hr (0.00168 lb/MMBtu), which is lower than 33 of the 49 Clearinghouse listings. Therefore, the exclusive use of natural gas in the combined cycle units is proposed as BACT for SO_2 emissions.

5.2.6 BACT Associated with Startup and Shutdown

Operation of the CC units requires that intermittent modes of transient operation must periodically occur, including the typical operation of startup and shutdown which is a basic operation of an electric generating facility. CC unit operation during startup and shutdown is different than steady-state operation. As such, the proposed BACT limits in Sections 5.2.1 to 5.2.4 should only be applicable during normal operations. During startup and shutdown periods, conditions exist in which the

---

[13] 42 Fed. Reg. at 53,785.

[14] 70 Fed. Reg. at 8,320.

emission control equipment is less effective. Therefore, work practice standards are proposed in lieu of numerical emission limits during periods of transient operation.

5.2.6.1 Startup and Shutdown Operations Overview

During startup and shutdown conditions, the emissions control features (DLN combustor, SCR system, and oxidation catalyst) are less effective than under the steady state conditions that occur during normal load operations, between minimum load and full load. In particular, the SCR and oxidation catalyst systems require time to reach minimum operating temperatures in order to effectively control emissions. The periods of startup and shutdown are defined below.

> **Startup** – the period from when the combustion turbine is started until it reaches the minimum emissions compliance load (MECL)
>
> **Shutdown** – the period when the load on the combustion turbine is decreasing from the MECL

5.2.6.2 Startup and Shutdown BACT

The following work practice standards are proposed as BACT for NOx, CO, and VOC during periods of transient conditions which include startup and shut down:

- Take all reasonable actions to minimize the magnitude and duration of elevated emission conditions during these transient periods
- Employ good operation and maintenance practices, including on associated pollution control technologies
- Comply with emission monitoring, recordkeeping, and reporting requirements
- During startup, initiate reagent flow in the SCR once the flue gas reaches the requisite temperature for NOx control
- During shutdown, maintain reagent flow in the SCR until the flue gas temperature falls below the requisite temperature for NOx control
- During startup or shutdown of the duct burner, maintain reagent flow in the SCR consistent with technological limitations, manufacturer's specifications, and good engineering and maintenance practices for the SCR to minimize emissions to the extent reasonably practicable

5.2.7 BACT for GHG Emissions

5.2.7.1 Formation

Greenhouse gases (GHGs) emitted due to the combustion of natural gas in a combined cycle unit include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Based on the emission calculations summarized in Section 3.0, CO_2 represents 99.9% of the GHG emissions from a combined cycle unit on a carbon dioxide-equivalent (CO_2e) basis.

5.2.7.2 Step 1 - Available GHG Control Technologies

The only post-combustion technology for controlling CO_2 emissions is carbon capture, utilization, and storage (CCUS). Accordingly, CO_2 emission controls evaluated for potential availability for the combined cycle units are 1) energy efficiency, 2) use of low carbon fuels, and 3) CCUS. Each of these control alternatives are discussed in the following sections.

Combined Cycle Unit Energy Efficiency

CO_2 is a product of combustion of fuels containing carbon, which is inherent in any power generation technology using fossil fuel. The theoretical combustion equation for CH_4, for example, is:

$$CH_4 + 2\ O_2 \rightarrow CO_2 + 2\ H_2O$$

Consequently, CO_2 emissions are the essential and intended product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by impurities or by imperfect combustion. As a result, the only effective means to minimize the amount of CO_2 generated by a fuel-burning unit is through maximization of efficient use of the combustion heat, thereby resulting in the lowest quantity of fuel used per product. For a combined cycle unit, fuel efficiency is expressed as heat rate (i.e., Btu/kWh), and high fuel efficiency corresponds to a low heat rate. Minimizing the amount of fuel required to produce a given amount of electrical power output results in the lowest amount of CO_2 generated during the combustion process. Efficiency in a combined cycle unit can be achieved through good engineering design and good combustion/operational practices.

Design - Combined-cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A CT operates on the Brayton cycle, and the HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the very high fuel efficiency that is associated with combined-cycle units.

The natural gas CT technology proposed for the project is the high efficiency Mitsubishi M501JAC CT. The high-efficiency primary components of the turbine, including the upgrade components to be installed after the first turbine inspection, result in high overall efficiency. In addition to efficient turbine components, CTs are designed with evaporative inlet air cooling or inlet fogging. These devices are used during higher ambient air temperature operating conditions in order to lower the temperature and increase the density of the inlet combustion air. Increasing air density reduces the power required to compress the air before it is used in combustion, thus increasing the overall energy efficiency of the CT on hot days.

One of the primary causes of efficiency loss for a combined cycle unit is CT compressor fouling. As a preventive measure, CTs are designed such that inlet air to the CT passes through a high efficiency filtration system, which reduces the contaminants that cause compressor fouling.

CTs have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the CT and protect personnel and equipment around the machine, CTs are designed with insulation blankets applied to the CT casing. These blankets minimize heat loss through the CT shell and help improve overall efficiency of the machine.

Finally, CTs are designed with sophisticated instrumentation and controls to automatically manage operation of the CT. The control system is a digital-type, is supplied with the CT, and controls all aspects of the turbine's operation, including the fuel flow rate and burner operations to achieve high combustion efficiency. The control system monitors operation of the unit and modulates fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance under all operating cases.

Likewise, the Rankine cycle HRSGs are efficient by design. These heat exchangers are designed to capture as much thermal energy as possible from CT exhaust gases and duct burners. HRSGs take the heat from the CT exhaust and use this heat to convert boiler feed water into steam, which is used to drive a steam turbine. Maximizing steam generation increases the steam turbine's power

generation, which maximizes overall plant efficiency. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation on all gas path surfaces exposed to ambient air. Insulation minimizes heat loss to the ambient air, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

Good Combustion and Maintenance Practices - CTs have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the CT is operated, the unit experiences degradation and some loss in performance. The CT 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: combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to maintain highly efficient operation. Also, while compressor fouling is minimized by design, to address compressor fouling that does occur, the compressor is cleaned periodically using online and offline water wash systems.

HRSG maintenance is also important. HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the high temperature CT exhaust gas. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. Although filtration of the inlet air to the CT minimizes fouling, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the heat transfer efficiency of the HRSG tubes is maximized.

Finally, minimizing the number and quantity of steam vents and the timely repair of steam leaks is important in maintaining the plant's efficiency. A combined-cycle unit has several locations where steam is vented from the process, including the deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These steam vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially reduce the efficiency of the heat transfer surfaces. Minimizing the number and quantity of steam vents and repairing steam leaks in a timely manner is important in maintaining the plant's efficiency.

Clean/Low Carbon Fuels

The CAA includes clean fuels in the definition of BACT; therefore, clean or low carbon fuels should be considered as a potentially available control technology for GHG emissions – provided they would not redefine the proposed source. GHG emissions from fuel combustion depend on the carbon content of the fuel. On a heat input basis, combustion of natural gas results in lower GHG emissions than the combustion of other fossil fuels.

Carbon Capture, Utilization, and Storage

The only potential post-combustion control technology for CO_2 emissions is CCUS. CCUS is an integrated suite of technologies that has the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then either use it or pump it into deep underground geologic formations for safe, secure, and permanent storage. Geologic storage refers specifically to the process by which CO_2 is pumped underground into rocks such that it is permanently trapped so it cannot enter the atmosphere. Captured CO_2 can also be transported and pumped into oil fields and utilized for enhanced oil recovery (EOR).

5.2.7.3 Step 2 - Technical Feasibility of GHG Control Technologies

The first two potentially available technologies identified above—energy efficiency and low carbon fuels—are technically feasible for the proposed units. However, for CCUS to be technically feasible, each individual step in the process must be technically feasible and the integrated suite of components must also be technically feasible such that each component integrates to work together without interfering with the essential operation of the units. As such, any potential barriers to the successful integration of these components must be considered in determining whether CCUS is technically feasible for the proposed units.

To date, CCUS has not been demonstrated at commercial scale on a natural gas-fired combined cycle (NGCC) unit. In an effort to advance technology development, Research & Development (R&D) programs are currently being funded by the United States Department of Energy (DOE) in cooperation with technology and industry partners to develop options, reduce project uncertainty, and improve technology deployment costs and performance. According to DOE:

> *The successful development of advanced CO_2 capture technologies is critical to maintaining the cost-effectiveness of fossil fuel-based power generation. Today, there are commercially available First-Generation CO_2 capture technologies that are being used in various small-scale industrial applications. At their current state of development, these [CO_2 capture] technologies are not ready for widespread deployment on fossil fuel-based power plants for three primary reasons. DOE is focused on supporting research and development (R&D) of novel technology solutions that address the three major issues with existing commercial CO_2 capture technology.*
>
> - *Reducing the impact of CO_2 capture on power generating capacity;*
> - *Scaling up novel CO_2 capture technologies to the necessary size for full-scale deployment at fossil energy power system; and*
> - *Improving the cost effectiveness of novel technologies for CO_2 capture so that fossil-based systems with carbon capture are cost competitive.*
>
> *. . .The Carbon Capture Program's approach to achieve these goals is to utilize a combination of developments in process chemistry, new chemical production methods, novel process equipment designs, new equipment manufacturing methods, and optimization of the process integration with other power plant systems (e.g., the steam cycle, cooling water system, carbon dioxide compression, etc.). Additionally, advances in boiler/gasifier technologies, materials of construction, process stream handling, heat integration, compression technologies, gas cleanup and separation, and power cycle technology under development within the Department's Clean Coal Research Program provide synergistic benefits are also required to meet program goals.*[15]

Notably, these technical challenges are perhaps more pronounced for gas-fired generation, due to unique issues associated with gas combustion at combined-cycle units and the previous focus on steam boilers. As stated by DOE:

> *Because of the many similarities between natural gas and coal fired power systems, DOE's current CCUS program does address many natural gas issues. However, because natural gas CCUS faces some unique issues, more [research, design, development, and*

[15] U.S. Dep't of Energy, *Carbon Capture R&D*, https://www.energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd (last visited Jan. 24, 2020).

> *demonstration] RDD&D is needed to focus on natural gas CCUS at a relevant scale. DOE is prepared to support a demonstration program to evaluate the adoption of these technologies and to reduce the cost of carbon capture for natural gas power systems.*[16]

EPA has likewise recognized the differences between coal-fired and gas-fired units in questioning whether full or partial CCUS is technically feasible for NGCC units. In light of those concerns, EPA rejected CCUS in determining the best system of emission reduction for GHG emissions from NGCC units in 2015. Specifically, EPA stated the following:

> *[T]he CO_2 concentration in the flue gas of a natural gas combustion turbine is much lower (usually approximately 4 volume percent) than the CO_2 concentration in the flue gas stream of a typical coal-fired plant (which is approximately 16 volume percent for a supercritical pulverized coal or circulating fluidized bed unit) and of the syngas of an IGCC unit (in which CO_2 can be as high as 60 volume percent). Therefore, the overall amount of CO_2 that can be captured in a CCS project is likely lower. Finally, unlike Subpart Da affected facilities, where there are full-scale plants with CCS that are currently under construction or in advanced stages of development, the EPA is aware of only one demonstration project, which is an approximately 40 MW slip stream installation on a 320 MW NGCC unit.*[17]

As previously mentioned in Section 4.4.7, EPA promulgated 40 CFR Part 60, Subpart TTTT which applies to new fossil fuel fired electric generating units including natural gas-fired combustion turbines. In promulgating these standards, EPA rejected CCUS as the best system of emission reduction for natural gas-fired combustion turbines because they did not have sufficient information to determine whether implementing CCUS was technically feasible.[18] In addition, EPA noted that the DOE has not yet funded a CCUS demonstration project for a natural gas-fired combined cycle unit and no natural gas-fired combined cycle CCUS demonstration projects are operational or being constructed in the United States. EPA has also proposed to reverse its prior conclusion that partial capture and sequestration is the best system of emission reduction for new coal-fired power plants, and in that action EPA did not propose any changes to its prior determination regarding the technical feasibility of CCUS for new combustion turbine facilities.[19] As part of its proposal to amend 40 CFR Part 60, Subpart TTTT, EPA concluded "…that CCS is not adequately demonstrated in certain key respects…" including availability of geologic sequestration sites, the scarcity of water needed for CCUS in certain areas of the country, and ongoing issues with successful demonstration of carbon capture technologies. Accordingly, the Agency revised its previous conclusion that partial CCUS represented the best system of emission reduction (BSER) for control of GHG emissions from newly constructed EGUs.[20]

The technical feasibility of each component of a CCUS system is discussed further below.

---

[16] U.S. Dep't of Energy, *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf (last visited Jan. 24, 2020).

[17] 79 Fed. Reg. 1,430, 1,485 (Jan. 14, 2014).

[18] 80 Fed. Reg. 64,510, 64,612 (Oct. 23, 2015).

[19] 83 Fed. Reg. 65,424, 65,424 (Dec. 20, 2018).

[20] *Id.* at 65,441.

CO_2 Capture

CO_2 capture is the first step in post-combustion control of CO_2 through CCUS. Capture is the engineered process of separating CO_2 from flue gas or upstream fuel sources. CO_2 gas separation technologies have been developed and employed in the industrial sector (e.g., petroleum refining and natural gas purification) for commercial purposes for more than 70 years.[21] Also, CO_2 capture on a small scale has been happening for many years in the petroleum, ethanol, and industrial chemical industries. While having been deployed for many years in the industrial sector for commercial uses, the technology has not been deployed to date at commercial-scale as an environmental control technology. CO_2 capture is being evaluated for emissions reductions from industrial facilities such as cement and steel manufacturing, coal-fired power plants, and natural gas-fired power plants, but it has never been installed on a commercial- scale NGCC power plant. NGCC power plants inherently emit less CO_2 than other fossil fuel generation sources such as coal or petroleum systems, so capture technologies for NGCC systems have not historically been used to generate a CO_2 stream for commercial purposes nor have they been the focus of R&D for CO_2 capture for GHG emission reductions.

Smaller-scale carbon capture systems have been demonstrated on several power generation facilities as shown in Table 5-1. All but one of these systems have been on coal-fired EGUs.

Table 5-1: Power Generation Units with CCS in North America at Commercial Scale

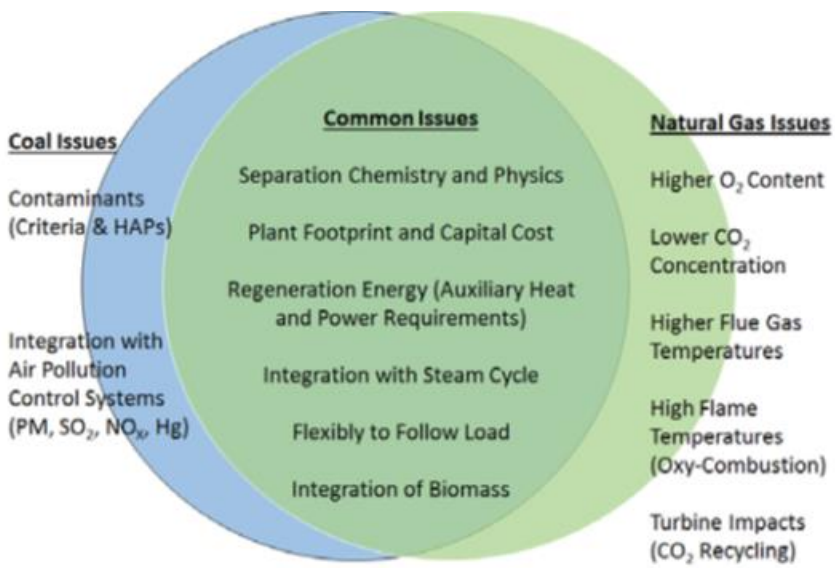
Project	Country	Fuel Type	Supplier/Technology	Tonnes CO_2 Captured per day	Project Start Date
Bellingham	U.S.	Natural gas CC (40 MW slipstream)	Fluor/Econamine FG PlusTM solvent	330	1991 - 2005
Mountaineer	U.S.	Coal boiler (20 MW slipstream)	Alstom/Ammonia (chilled)	300	2009 - 2011
Plant Barry	U.S.	Coal-fired boiler (25 MW slipstream)	MHI/KM CDR Process® and KS-1™ solvent	500	2011 - 2015
Trona	U.S.	Coal-fired boiler (108 MW)	McGee/ABB Lummus Crest/MEA solvent	800	1978 - present
Boundary Dam	Canada	Coal-fired boiler (110 MW)	Shell Cansolv/DC-103 solvent	2,740	2014 – present
Petra Nova	U.S.	Coal-fired boiler (240 MW slipstream)	MHI/KM CDR Process® and KS-1™ solvent	4,800	2016 - present

[21] *Report of the Interagency Task Force on Carbon Capture and Storage* (Aug. 2010), https://www.epa.gov/sites/production/files/2016-08/documents/ccs-task-force-report-2010.pdf (last visited Jan. 24, 2020).

The Bellingham NGCC project in Massachusetts operated from 1991-2005 to capture CO_2 for use in the food industry rather than as an environmental control system. Operating for this purpose allowed the carbon capture system to function essentially independently from the NGCC, diminishing the effects of power cycle fluctuations on carbon capture operations, and largely eliminating the impacts of outages in carbon capture equipment on power production.

Although, as shown in the table above, the majority of post-combustion carbon capture R&D has been done on coal-fired applications to date, the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) has been expanding its focus to all fossil fuel power generation and industrial carbon capture. Much of the CO_2 capture R&D is applicable to natural gas combined cycle units and to the industrial sector such as refineries, ethanol, cement, and steel plants. However, the lower CO_2 concentration in NGCC flue gas dictates that any solvent-based CO_2 absorber must be sized comparatively larger than the one used in a coal capture system; or for a membrane system, more energy and membrane area are required. (See Figure 5-1) NGCC flue gas also has higher oxygen content than other combustion source flue gases, which may cause faster rates of oxidative degradation to solvents.

Figure 5-1: Comparison of Coal and Natural Gas CCUS Issues[22]



Amine solvent is the most developed technology for post-combustion carbon capture. DOE is working on transformational technologies in all areas such as solvents, sorbents, membranes, hybrid, and cryogenic capture systems. As explained by the Fossil Energy Research and Development (FER&D) program, "FER&D will continue to focus on CCS and activities that increase the efficiency and availability of advanced power systems integrated with CCS."[23] This is evident from the recent DOE

[22] U.S. Dep't of Energy, *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf (last visited Jan. 24, 2020).

[23] U.S. Dep't of Energy, *Carbon Capture, Utilization, and Storage: Climate Change, Economic Competitiveness, and Energy Security* (Aug. 2016), https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20-%20Carbon%20Capture%20Utilization%20and%20Storage_2016-09-07.pdf

awarded projects and work in many fronts including 1) Front-End Engineering Design (FEED) studies, 2) expansion of the National Carbon Capture Center (NCCC) managed by Southern Company to include testing for natural gas power plants, and 3) large pilot-scale projects at Technology Centre Mongstad (TCM) to simulate NGCC gas conditions. These efforts include nine FEED studies for CO_2 capture systems on both coal and natural gas power plants, with four being performed for retrofit of NGCC power plants with CCS described below:

- Bechtel National will perform the FEED study for a retrofit 2x2x1 NGCC to Panda Energy Fund's plant in Texas with a non-proprietary solvent.
- Electric Power Research Institute will conduct a study for a retrofit on California Resources Corporation's 550 MWe Elk Hills Power Plant (NGCC unit) using Fluor's amine based Econamine FG Plus process to capture 75% of the CO_2 produced.
- Southern Company will complete a study for installation of a Linde-BASF solvent process on an existing NGCC plant in the Southern system.
- The University of Texas at Austin will do a FEED study with the Piperazine Advanced Stripper process at the Mustang Station of Golden Spread Electric Cooperative in Texas.

Based on the lack of commercial deployment at similar NGCC units and barriers to applying second generation research to similar commercial scale NGCC units, carbon capture is technically infeasible for this application.

CO_2 Compression and Transport

In order for captured CO_2 to be permanently sequestered or geologically stored, it must first be compressed "from near atmospheric pressure to a pressure between 1,500 and 2,200 psia . . . ."[24] While compressing CO_2 is feasible, it is extremely energy-intensive and expensive. To reduce the energy intensity related to compression, DOE is evaluating various compression concepts using computational fluid dynamics and laboratory testing that will lead to development of prototypes and field testing. Their research efforts include "development of intra-stage versus inter-stage cooling, fundamental thermodynamic studies to determine whether compression in a liquid or gaseous state is more cost-effective, and development of a novel method of compression based on supersonic shock wave technology."[25]

Some pipelines exist today that transport compressed (dense-phase) CO_2. Since the 1970s, CO_2 has been transported in pipelines to oil fields for use in enhanced oil recovery (EOR) operations. The majority of this CO_2 has been sourced from naturally occurring underground geologic deposits because off-takers of CO_2 transported for use in EOR operations require steady-state production of CO_2.[26] Naturally occurring geologic deposits of CO_2 provide this steady delivery of CO_2. In contrast, the intermittent operation of power plants means that the transportation of CO_2 captured from those power plants is discontinuous and unpredictable. Additionally, existing CO_2 pipelines are not considered to be common carrier (open access) pipelines and are dedicated, with limited capacity, to accommodate private oil industry CO_2-EOR projects. As such, these existing pipelines were not

---

[24] NETL, *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap* (Dec. 2010), https://www.netl.doe.gov/File%20Library/Research/Carbon%20Seq/Reference%20Shelf/CCSRoadmap.pdf

[25] U.S. Dep't of Energy, *A Review of the CO_2 Pipeline Infrastructure in the U.S.* (Apr. 21, 2015), http://energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf.

[26] Melanie D. Jensen, et al., *Operational Flexibility of CO_2 Transport and Storage*, 63 Energy Procedia 2715-2722 (2014), *available at* https://reader.elsevier.com/reader/sd/pii/S1876610214021092?token=70E82B8033A2B829AA2BFCC09057DCD9BA9342E54B9BAF82207EA43021E7A5E22AD99271091071189B0D6E325F938146.

designed to accommodate the intermittent flow of CO_2 from power plants. As a consequence, for CO_2 compression and transport to be a technically-viable component of CCUS, new CO_2 pipelines for commercial-scale capture operation would be required to be developed.

Still, construction of a CO_2 pipeline would be like construction of a natural gas pipeline, with applicable regulations, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. The proposed NGCC units at Plant Barry would need to construct a CO_2 pipeline to a suitable location where injection for saline formation storage or CO_2-EOR would take place if it were to pursue CCUS as a CO_2 control option. While it may be technically feasible to construct a CO_2 pipeline, considerations regarding the land use and availability need to be made. Based on experiences in the CO_2-EOR industry, compression and transport of CO_2 is considered technically feasible

CO_2 Geologic Storage Options

The pumping of CO_2 into deep geological formations or the utilization of the CO_2 for EOR are the last steps of the CCUS process. Both processes can lead to the long-term secure storage of CO_2. These storage operations can include pumping into a wide range of geologic formations including deep saline reservoirs, active and abandoned oil and gas fields, and other rock formations such as un-mineable coal seams and basalt formations. There are no un-mineable coal seams or basalt formations in proximity to the proposed NGCC units at Plant Barry, so these formations are not feasible as storage options in this case. While a few coal seams in North Alabama have been tested as potential storage sites, CO_2 storage in subsurface coal beds in not further considered in this analysis because of the greater distribution and storage capacity of CO_2 storage resources available in deep saline formations in closer to Plant Barry.

While active oil fields are present in South Alabama, no CO_2-EOR operations are currently active in the State of Alabama. The transition of an existing oil field to a CO_2-EOR operation requires significant capital expenditures[27] and permitting of the CO_2 pumping operations. Moreover, not all oil fields are amenable to CO_2-EOR operations. Significant feasibility studies would need to be planned to determine if CO_2-EOR would be a cost-effective option for recovery of oil in each field being considered. The potential for an oil company to engage in an agreement to use CO_2 for EOR also largely depends on the price of oil. As such, using CO_2 for EOR operations is not currently feasible for this application.

Alternatively, deep saline formations are present in the geologic subsurface in South Alabama that have been assessed to be feasible for safe geologic storage of CO_2. Safe, secure, and permanent geologic storage in deep saline formations has been successfully performed throughout the world and in the United States but requires the presence of a sufficiently permeable rock formation (typically sandstone or carbonate) which is sealed by rocks on top that have a very low permeability. These formations need to be at least 1 kilometer (km) deep to ensure that the CO_2 is stored as a dense phase, also called a supercritical fluid. To protect underground drinking water aquifers, CO_2 storage is only permitted in saline formations that are saltier than 10,000 parts per million (ppm) total-dissolved-solids per the EPA Class VI Underground Injection Control (UIC) regulations. The geologic seal (typically a shale formation or chalk) must be continuous over the entire area where the CO_2 is stored and free of defects such as permeable faults, fractures, or leaky wellbore penetrations. Additional considerations include an assessment of the risks of induced seismicity and the potential for CO_2 or brine leakage through preexisting boreholes. Brine is water containing dissolved salts that naturally

[27] Armpriester, Anthony. *W.A. Parish Post Combustion CO2 Capture and Sequestration Project Final Public Design Report*. United States: N. p., 2017. Web.

exists in a rock formation. To evaluate formations for suitability, extensive drilling and site characterization must be performed to certify a site to be geologically suitable for long-term geologic storage.

The CO_2 storage capacity estimates for the United States have been assessed by both the United States Department of Energy (DOE) and the United States Geological Survey (USGS). Both assessments indicate a large potential for storage, with median estimates ranging from 3,000 to 8,600 billion metric tons of CO_2. The economic potential, often referred to as a "storage reserve" is likely to be significantly lower, but how much lower is not fully evaluated. Regardless, conservative estimates are large compared to the amount of CO_2 emitted in the United States each year[28] - suggesting that storage capacity is unlikely to be a limiting factor in the United States.

Since CO_2 capture technology has to date not been applied to a NGCC power plant, there are currently no CO_2 geologic storage projects related to CO_2 sourced from NGCC power plants. Saline formation injection demonstration projects in the US and which Southern Company was a research participant include:

Plant Daniel Pilot Injection Project - This project was conducted by DOE's SECARB Partnership and the Electric Power Research Institute (EPRI) and involved drilling one injection well and one observation well into the Tuscaloosa Formation (a deep saline formation) at Mississippi Power's Plant Daniel. Approximately 3,000 tons of CO_2 were pumped into the injection well into a deep saline formation approximately 8,500 feet below ground surface (bgs) and monitored in the adjacent monitoring well. The pumping was completed in 2008, and monitoring was completed in 2010. The project included site characterization, permitting, CO_2 pumping operations, and monitoring of the small amount of CO_2 pumped into the subsurface.

Plant Barry Anthropogenic CCUS Demonstration/SECARB Phase 3 - Southern Company built and operated a 25 MW coal slipstream amine post-combustion capture plant at Plant Barry beginning in 2011. CO_2 subsurface pumping operations began in 2012 and the pumping operations concluded in 2014. The project was decommissioned in 2015. The injection wells have been plugged and abandoned. The capture project provided CO_2 for SECARB funded storage research. The project included drilling two injection wells and two observation wells into the Paluxy Formation (a deep saline formation) located in Citronelle Dome, geologically above the Citronelle Oil Field in South Alabama. The project pumped nearly 120,000 tonnes of CO_2 over three years. The project included construction and operation of a 12-mile pipeline that connected Plant Barry to the Citronelle Dome injection site. The project informed DOE and industry how effective monitoring and verification protocols for geologic storage could be deployed in the field.

Kemper County Energy Facility/Phase II CarbonSAFE - In Kemper County Mississippi, a DOE project awarded to the Southern States Energy Board (SSEB) provided funding for the drilling of three deep saline geological characterization wells to evaluate the facility of the storage of CO_2 in three separate saline reservoirs under that site. The results were positive in that good rock properties existed for the pumping and long-term safe storage of CO_2 at that site. No CO_2 was pumped as a pilot demonstration with this project. DOE has recently announced additional funding opportunities to continue additional work at sites within the CarbonSAFE program.

---

[28] NETL, *FE/NETL CO_2 Saline Storage Cost Model* (Sept. 30, 2017), https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=2403.

Other geologic storage projects conducted in Europe, the United States, Canada, Australia, and Japan since 1990 with commercial scale storage operation as listed below in Table 5-2.

Table 5-2: Commercial-Scale Saline Formation CO_2 Pumping and Storage Projects

Owner/Operator	Location	CO_2 Amount Sequestered
In-Salah (a joint venture of Solargraph, BP, and Statoil)	Algeria in North Africa	1 million tons per year since 2004 CO_2 source: natural gas production upgrading operations
Statoil (Norwegian oil company)	Utsira Sandstone, saline formation under the North Sea associated with the Sleipner West Heimedel gas reservoir	Approximately 1 million tpy; equivalent to the output of a 150 MW coal-fired power plant CO_2 source: natural gas production upgrading operations
Southeast Regional Carbon Sequestration Partnership	Cranfield oil field in Mississippi	Approximately 100,000 tons per month (more than 6.6 million tons since 2010) CO_2 source: Jackson Dome naturally occurring geologic source
Midwest Regional Carbon Sequestration Partnership	Mount Simon Saline Sandstone Formation in Illinois	Approximately 9,490,000 tons since 2011 CO_2 source: ADM ethanol plant
Shell Canada, Chevron Canada and Marathon Oil Sands	Fort Saskatchewan, Alberta, Canada	Approximately 1 million tpy, beginning November 2016 CO_2 source: hydrogen plant

Although geologic research storage projects involving Southern Company and other entities exist, it is noted that large commercial scale storage projects from NGCC plants do not currently exist.

Other Feasibility Considerations - When CO_2 is pumped into a geologic formation, it occupies small voids within the geologic structure known as "pore space." Before pumping CO_2 into the subsurface for geologic storage, the storage operator must own the pore space, have permission from the owner, or otherwise have the right to use the pore space. The laws concerning property rights over pore space is a basic concern of state law rather than federal law and varies from state to state. The issue of pore space property rights is complicated by the fact that for a large CO_2 storage project, the CO_2 plume may extend over many square miles, and impacts to formations may extend over an even larger area. For large projects, multiple property or pore space owners are likely to be involved in the process of identifying and acquiring pore spaces rights. Addressing issues related to property rights and competing uses of the subsurface mineral rights could have an impact on the feasibility of CO_2 storage. Currently the State of Alabama does not have any clear defining laws addressing the potential legal issues related to pore space facing large commercial-scale injection of CO_2 for long-term geologic storage. For example, the ownership of property and mineral or groundwater rights relevant to use of pore space for long-term geologic storage are not well-established. Fee simple property rights may not be available, and subsurface rights divorced from fee and surface rights are

complex. As a result, CO_2 storage in a geologic formation lies beyond the direct control of the source in most cases.

In addition to pore space ownership, there are issues associated with CCUS related to long-term responsibility for the stored CO_2. Some states have enacted laws governing these issues, but they vary. This is a problem for projects that operate in states without such laws and for projects that cover multiple states. Some states are beginning to address these issues, but no clarification has been made at a State level in Alabama to address the issues.

The closest geologic structure suitable for large volume geologic storage sourced from Plant Barry specifically, is the geologic structure named Citronelle Dome located approximately 12 miles from Plant Barry. As described previously, CO_2 has been pumped into the Citronelle Dome for field testing. It has been demonstrated to be a suitable storage structure for large-volume CO_2 storage. Pumping operations ceased in September 2014, with post-project monitoring of the 120,000 metric tons of CO_2 pumped for storage. However, Alabama Power has no legal rights to any pore space in the Citronelle Dome.

In light of the uncertainties regarding commercial scale CO_2 pumping and storage, including the long-term liabilities, the absence of EOR operations in the state, and the lack of legal access to pore space in the Citronelle Dome, CO_2 storage is not considered technically feasible in this application.

Integration

Regardless of the potential availability or feasibility of the individual components of CCUS, the integration of these systems at a commercial scale NGCC unit must also be evaluated. As an initial matter, no integrated CCUS system has ever been constructed to serve a commercial scale NGCC. And although there are two CCUS systems currently in operation at coal-fired generating facilities, only one of those is fully integrated: the SaskPower Boundary Dam CCUS Project. The Boundary Dam project processes essentially all of the flue gas from the 110 MW Boundary Dam coal-fired power station Unit 3. Boundary Dam experienced operational problems from its initial opening in 2014, including significant challenges in 2017 that led to lengthy outages and a much lower capture rate than originally anticipated. Operations have steadily improved since that time but remain below design CO_2 production levels. However, despite receiving $240 million from the Canadian federal government, the economic viability of the $1.5 billion 110-MW project remains questionable - an April 2016 Parliamentary Budget Office report found that CCUS at Boundary Dam doubles the price of electricity produced by this facility. Moreover, after that study was released, the initial operational challenges forced the facility to renegotiate its EOR contracts resulting in a significant reduction in annual revenue over the life of the project.

The only other commercial scale CCUS system currently in operation is the Petra Nova commercial demonstration project at the W.A. Parish coal-fired power plant Unit 8, which began operation in January 2017. The facility is not an integrated system because it operates on a slip stream of the unit's total flue gas. Moreover, the project requires an entirely separate natural-gas fired power plant to provide the power needed to operate the carbon capture and compression process. Thus, although the system was designed to capture approximately 33 percent of the CO_2 emitted from Unit 8 (90 percent capture of a 240 MW slipstream from the total 654 MW capacity of Unit 8), the NGCC providing power to the system will emit CO_2 as well, resulting in a lower net reduction in CO_2 emissions. Like Boundary Dam, Petra Nova received significant financial assistance from the government - $167 million from the U.S. Department of Energy - without which the $1 billion project may not have been possible.

The operational success of these two projects is encouraging, but difficulties with integrated CCUS facilities on a larger scale are expected to result from load fluctuations, outages, and CO_2 purity. Also, the reliability of the host-generating unit could be affected by problems associated with the CCUS processes as described below:

- **Loading** - Power plants do not run consistently; their load fluctuates as needed to meet electricity demand, which may affect the CCUS equipment. EOR operations historically have been supplied with CO_2 from some steady source, such as a natural geologic deposit of CO_2 or from a natural gas purification process. The knowledge available on CO_2 sequestration is mostly from EOR operations.
- **Outages** - Power plants experience planned and forced outages. During these outages, the CCUS processes would be suspended. It is unknown how this suspension will affect the injection operations and equipment.
- **CO_2 Purity** - CO_2 streams from power plants may not be the same as CO_2 produced from natural geologic deposits or from natural gas purification processes. It is unknown if CO_2 streams of varying composition will be able to be integrated into the same pipeline network.
- **Reliability** - Reliability of an integrated CCUS system, including the host power plant, will be affected by problems arising in each CCUS process. Because CO_2 capture, transport, and storage have not yet been integrated at a commercial scale NGCC power plant, it is unknown how the three processes will interact with each other and the host plant. For example, it is unknown how problems at the capture unit will affect the pumping and storage operations. Furthermore, if the capture unit fails and the CO_2 pumping process stops, there could be implications to the pressure in the geologic storage formation. If CO_2 cannot be pumped, the host generating unit may also not be able to run unless it is able to discharge its CO_2 emissions while the problems in the CCUS processes are addressed. Problems in one CCUS process will affect the operations of other processes and thus impact the reliability of the system and potentially the ability of the host generating unit to deliver reliable power to customers who depend on the end product-electricity.

Close attention to both Petra Nova and Boundary Dam commercial demonstration projects is crucial as they continue to develop operational expertise since there is very limited industry-wide operational experience.

In addition to the projects described above, another example is Southern Company's research project at Alabama Power's Plant Barry Anthropogenic CCUS Demonstration/SECARB Phase 3 project, which began integrated operation in 2012. It was one of the first projects in the world to study the integration of CO_2 capture operations at a coal plant with pipeline transportation and saline reservoir storage. This project was not commercial scale and consisted of CO_2 capture from the flue gas of a coal-fired boiler rather than from a NGCC unit and operation of the generating units was not dependent on operation of the capture system.

Southern Company has been involved in several demonstration projects that provided some experience with the integration of CCUS' three-step process (i.e., capture, compression and transport, and storage/use) on a commercial-scale power plant. However, these projects support the conclusion that CCUS is currently far from an adequately demonstrated CO_2 control technology at commercial scale on a NGCC power generation unit and requires additional research and development prior to full commercial scale implementation.

CCUS is different from other air pollution control technologies, because, if required for compliance, responsibility may need to be shared between multiple parties, not just the power plant owner/operator. For example, if CO_2-EOR is utilized to store CO_2, the power generator will likely have

to enter into a contract with a third party to transport the CO_2 and demonstrate storage in the oil field. Under such arrangements where the power plant is dependent on a third party for compliance, there are always risks of contract breeches, dissolution of the contract parties, or other issues, including long-term responsibility of stored CO_2, that cannot be foreseen that could put the ability of the power plant to meet electricity demand at risk.

CCUS Conclusions

As discussed above, CCUS has the potential to reduce CO_2 emissions as a post-combustion control alternative. However, the technology has only been employed at small commercial scale at two coal-fired facilities and the success of those two projects has been limited. To date, CCUS has never been applied at a commercial scale NGCC unit. While each of the individual components of CCUS, including post-combustion capture, compression, pipeline transportation, and injection for storage in geologic formations are under development and in practice in other industries, additional research and development is needed before all of the components can be reliably integrated into a commercial scale power plant that must function efficiently across a range of operating conditions.

As EPA states in its GHG BACT Guidance (2011), "CC[U]S may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. … Furthermore, CC[U]S may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, considering the integration of the CC[U]S components with the base facility and site-specific considerations."[29] Since significant challenges remain, for which technical solutions are not currently commercially available, CCUS is not technically feasible for the proposed NGCC units.

The elements of CCUS – capture, compression, transport, and storage/or utilization – have been technically demonstrated in various industries, but they have never been integrated and applied at commercial scale on NGCC units in the electric power industry. More effort and research are required to advance CCUS for gas-fired power generation before it can be deemed sufficiently feasible to form the basis of a BACT determination. As the Environmental Appeals Board has confirmed, technologies in the research phase of development or with unresolved technical difficulties in application would not be considered BACT.[30]

Step 2 of the top-down BACT analysis is the elimination of technically infeasible options. EPA considers a technology to be technically feasible if it is available and applicable to the source type under review. A control technology should also be considered technically available or applicable if it has been demonstrated on an exhaust stream with similar physical and chemical characteristics. Based on the above discussion of CCUS, CCUS is eliminated as a technically feasible option as BACT consistent with EPA's regulations and guidance.

5.2.7.4 Step 3 – Ranking of Available GHG Control Alternatives

The technically feasible options include energy efficiency and the use of low carbon fuels. Energy efficiency includes the high thermal efficiency design of the NGCC units as well as the planned upgrade improvements that are part of the project, as described in the previous sections. Accordingly,

---

[29] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (Mar. 2011), https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf.

[30] In re Cardinal FG Co. 12 E.A.D. 153 (2005).

efficient units and the use of low carbon natural gas fuel are considered the top-level available alternatives for control of GHG emissions from combined cycle units.

5.2.7.5 Step 4 - Economic, Energy, and Environmental Impacts

Because energy efficient designs and the use of low carbon natural gas fuel are inherent in the proposed units, the impacts of those control options need not be evaluated under Step 4 and serve as the baseline against which to compare the cost-effectiveness and other impacts associated with other available control options (See 1990 Draft NSR Workshop Manual, at B.36[31]).

As demonstrated in Section 5.6.2.2 above, CCUS for control of CO_2 from a NGCC unit is not applicable or technically feasible. However, Alabama Power is also providing a cost assessment which independently confirms that CCUS must be rejected as the basis for a BACT determination for the combined cycle units. The costs associated with CCUS can be broken down into the same categories that the CCUS process is divided into: Capture, Compression and Transport, and Storage (or Use). Due to the size of the proposed combined cycle units, the GHG BACT cost analyses presented in Appendix F are based on a dedicated CCUS system for each combined cycle unit. Because the combustion turbines and supplemental duct burners will be capable of operating simultaneously, each CCUS system must be sized to accommodate the total flue gas and CO_2 flow rates from its associated turbine and duct burner.

CO_2 Capture and Compression Costs

CCUS costs can be adequately estimated for purposes of this study using published studies and government resources. The published CO_2 capture and compression costs studies relied upon represent cost on a "CO_2-Captured" basis. The CO_2-captured basis accounts for CO_2 that is removed from the process as a result of the installation and use of a control technology, without including any losses during compression, transport and storage. It is appropriate to use the CO_2 captured monetary estimates because the BACT analysis is based on emissions from a single stack source (e.g., the direct emissions from each combined cycle unit) and does not account for secondary emissions (e.g., the GHG emissions generated from the act of compressing the CO_2 to pipeline pressures).

Accordingly, cost estimates from the 2019 DOE/NETL Cost and Performance Baseline for Fossil Energy Plants Volume 1 (NETL-PUB-22638), the US Energy Information Administration's 2018 Cost and Performance Characteristics of New Generating Technologies: Annual Energy Outlook 2018, and the Global CCS Institute's 2017 Global Costs of Carbon Capture and Storage: 2017 Update were used to evaluate costs per ton of CO_2 captured. Even when narrowed to NGCC technologies, the costs of carbon capture and compression estimates can vary in published studies. Accordingly, three independent studies were evaluated. Notably, these studies are not intended to account for first-of-a-kind issues and costs that will be encountered by the first implementations of such technology at an NGCC. Thus, the cost analysis presented here and in Appendix F is conservative and higher costs are likely. The results of the cost analysis from each study, when adjusted to a consistent operating basis with the proposed units, indicate an average cost for only the capture (and compression) component of CCUS of $69 per ton of CO_2 captured.

[31] EPA, *Draft New Source Review Workshop Manual*, at B.37 (Oct. 1990) ("When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes.")

CO_2 Transport Costs

The cost of pipeline installation and operation are obtained from the NETL's document Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies (DOE/NETL-2019/2044) and the associated FE/NETL CO_2 Transport Cost Model. According to this document, the pipeline costs include pipeline installation costs, other related capital costs, and operation and maintenance (O&M) costs.

The closest potential carbon sequestration site to the proposed Project was found at the Citronelle Dome in Alabama, approximately 12 miles from the project location. For cost estimation purposes, a pipeline length of 12 miles is used. The FE/NETL CO_2 Transport Cost Model indicates that a 12-inch diameter pipeline would be appropriate for the projected volume of capture. NETL guidance on pipeline costs yields a final total capital expense associated with pipeline construction of over $17.9 million including 15% contingency and levelized annual O&M costs of over $262,100/year in 2020 dollars. Based on the projected volume of CO_2 capture, this translates to approximately $0.52 per ton of CO_2 captured for transportation costs.

Geological Storage Costs

Cost estimations for geological storage were developed using information and experience gained during the Plant Barry Anthropogenic CCUS Demonstration/SECARB Phase 3 project described previously at the proposed Citronelle Dome storage location. These estimates yield a final total capital expense of over $93.5 million including 15% contingency and levelized annual O&M costs of over $6 million/year in 2020 dollars. Based on the projected volume of CO_2 capture, this translates to approximately $3.78 per ton of CO_2 captured.

Overall Cost of Carbon Capture and Storage

Including the capture and compression costs for CO_2 emissions related to the combined cycle units, the cost to transport from the site, and the cost to sequester the resulting supercritical fluid into an appropriate site is estimated to be $73 per ton of CO_2 captured. Based on the size of the units, this equates to annual costs of $322 million.

This cost is plainly excessive, particularly given that the levelized cost of electricity from natural gas-fired combined cycle generation is reported to be between $183 million and $240 million per year.[32]

Moreover, this CCUS cost analysis is conservative as it evaluates the maximum design-case operating scenarios of the two units. However, under normal operating conditions, CO_2 emissions would be lower than the maximum design-case operating scenario, which will greatly increase the cost of CCUS on a dollar per ton of CO_2 captured.

In this analysis, partial CCUS was also considered. In order to meet an enforceable emissions limit, the initial size of the capture units and the capital investment would likely be similar in order to capture the same amount of CO_2 as the 90% capture CCUS system to account for reliability and performance issues that CCUS would inherently have. The same size capture system is required in order that the NGCC unit would still be able to provide reliable power to the end users when the CCUS system has reliability issues. As such, partial CCUS would be even more expensive per ton of CO_2 removed as the capital investment is the most significant part of the CCUS costs. On the other hand, if a smaller system was installed on each unit for partial CCUS, then the reliability issues associated with CCUS

[32] Lazard's Levelized Cost of Energy Analysis – Version 13.0, Lazard, (November, 2019).

would impact the NGCC's ability to provide reliable power to the end user while meeting an enforceable emissions limit in the same manner as full capture. Regardless, considering the quantity of CO_2 generated, this figure represents an unreasonable cost for GHG control leading to the conclusion CCUS, in addition to be technically infeasible, is cost prohibitive for the proposed project.

In addition to its direct costs, CCUS creates substantial indirect economic, environmental, and energy impacts. The energy impacts of CCUS implementation include the need for additional energy production to support on-site CO_2 compression and purification and further CO_2 compression at the wellhead. Additional combustion sources that emit CO_2 would be necessary to provide energy to these processes. For multiple reasons, the undue burden of applying a technology that has yet to be proven for combustion turbines, and the excessive cost to implement this technology, CCUS is eliminated from further review.

Use of high efficiency turbines, fueled by natural gas and employing good combustion/operating practices are the remaining control technologies and representative of BACT. A search of the RBLC was conducted to identify recently-permitted large natural gas-fired combined-cycle units with BACT determinations for GHGs. The results of this search are provided in Appendix E, Table E-6. A total of 82 natural gas-fired combined-cycle units that meet these criteria were identified. The measures concluded to be representative of BACT are identified in 62 of these listings. A total of 51 listings describe BACT as either energy efficiency or good combustion; an additional nine listings describe the use of low carbon-emitting fuels as BACT.

5.2.7.6 Step 5 – Evaluation of GHG BACT for the Combined Cycle Units

Selection of BACT

Step 5 of the top-down BACT analysis is the selection of BACT. Alabama Power proposes the following as BACT for GHG for the proposed combined cycle units:

- Use of combined-cycle technology,
- CT energy efficiency designs, practices, and procedures, and
- HRSG energy efficiency designs, practices, and procedures.
- Use of natural gas

Proposed GHG BACT Emissions Limit for the Combined-Cycle Unit

Alabama Power proposes a 2,445,022 tpy CO_2e emissions limit per combined cycle unit as GHG BACT for all operating cases, including during periods of startup and shutdown, averaged on an annual basis.

This numerical GHG BACT emissions limit is based on the exclusive use of natural gas in the combined cycle units. Compliance with this numerical GHG BACT emissions limit will be demonstrated by measuring and recording the total heat input to each combined cycle unit expressed in million British thermal units (Btu) per year. CO_2 emissions will be calculated using the methodology for calculating CO_2 emissions under the Acid Rain Program in accordance with 40 CFR 75[33], Equation G-4.

[33] 40 C.F.R. Part 75, App. G.

Annual methane and nitrous oxide emission rates will be calculated using emissions factors as defined in the Mandatory Greenhouse Gas Reporting Rule[34], Table C-2. CO_2e emissions will then be calculated using each GHG pollutant's respective Global Warming Potential (GWP) as defined in the Mandatory Greenhouse Gas Reporting Rule[35], Table A-1.

To ensure the inherent efficiency of each combined cycle unit remains high throughout all operating modes, Alabama Power will also meet an emission limit of 1,000 lb CO_2/MWh average on a gross output basis over a twelve (12) month operating period which is consistent with 40 CFR Part 60, Subpart TTTT[36]. Alabama Power will demonstrate compliance with the proposed emission limitation on an annual basis by measuring/monitoring total natural gas consumption and gross electrical output for each unit. Measuring and monitoring is a viable surrogate to ensure efficient operation during all operating periods. CO_2 emissions will be calculated using Equation G-4 under the provisions of the ARP, 40 CFR Part 75 using the heat input of the natural gas combusted on monthly basis. The total calculated CO_2 emissions on a monthly basis will be divided by the total gross power output in megawatt-hours generated on a monthly basis to obtain a CO_2 emissions rate expressed in pounds per megawatt-hour. A twelve operating month rolling average will be kept for the CO_2 emission rate (lb/MWh-gross).

In summary, Alabama Power proposes GHG BACT limits of 2,445,022 tpy CO_2e emissions limit per combined cycle unit. It is noted, Alabama Power will also meet the 40 CFR 60 Subpart TTTT limit of 1,000 lb CO_2/MWh-gross on a twelve (12) operating month average.

5.3 BACT for Auxiliary Boiler

5.3.1 BACT for Nitrogen Oxides Emissions

5.3.1.1 Step 1 - Available Auxiliary Boiler NOx Control Alternatives

NOx formation mechanisms for combustion sources are discussed in Section 5.2.1.1. The primary front-end combustion control method for boilers is the use of burners that are specifically designed to limit NOx formation. SCR and selective non-catalytic reduction (SNCR) can be used to remove NOx from boiler flue gas once it has been formed.

Low and Ultra Low NOx Burners

Burners specifically designed to minimize thermal NOx formation, generically referred to as Low NOx Burners (LNBs), control the mixing of fuel and air in a pattern that is intended to maintain low flame temperature and oxygen concentration in the flame zone. Some burner designs seek to control the flame shape in order to minimize the reaction of nitrogen in the combustion air with oxygen at the peak flame temperature. Others use air staging and/or fuel staging to develop flames that have fuel-rich and air-rich regions in order to reduce thermal NOx formation. The flame from an LNB is typically elongated compared to the short, intense flame produced by a conventional burner. According to the EPA, LNBs on natural gas-fired sources have emissions that are between 40 and 85% lower than with

[34] 40 C.F.R. Part 98, Table C-2.

[35] 40 C.F.R. Part 98, Table A-1. GWPs were determined using 40 CFR Part 98 Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1, effective January 1, 2014, which are consistent with ADEM's GWP per ADEM Admin Code R. 335-3 Appendix I.

[36] 40 C.F.R. Part 60, Subpart TTTT, Table 1.

conventional burners, with an emission range of between 0.05 and 0.14 lb/MMBtu (approximately 50 to 140 ppm).[37]

Ultra-Low NOx Burner (ULNB) designs were developed in response to a commercial demand for industrial steam generating units and boilers located in ozone nonattainment areas to achieve the emissions performance of SCR at a lower capital cost and without the requirement to use ammonia or urea as a NOx reducing reagent. In addition to features designed to minimize thermal NOx formation, ULNBs typically employ internal flue gas recirculation, rapid air/fuel mixing or other design features that minimize or eliminate the formation of fuel-rich regions within the burner flame, thereby essentially eliminating the formation of prompt NOx. ULNBs have been demonstrated to be capable of meeting NOx emission limits in the 7 – 10 ppm range or less.

Selective Catalytic Reduction

Described in more detail in Section 5.2.1.2, SCR involves the catalytically-promoted conversion of NOx in the flue gas of a combustion unit to elemental nitrogen and water using an injected reducing agent (ammonia or urea). The principal considerations associated with the potential use of SCR on small natural gas-fired boilers are whether a suitable location within the boiler tube passes exists within the required temperature zone, and the relatively high capital and operating costs relative to the amount NOx reduction potential.

Selective Non-Catalytic Reduction

SNCR is another post-combustion process that has been used to control NOx emissions from certain combustion process applications. This process involves the thermally-driven reduction of NOx using direct injection of a reducing agent (ammonia or urea) directly into the flue gas of the combustion process. The reducing agent must be injected where the flue gas temperature is in the range of 1,300 to 2,100°F, with an optimum operating temperature zone between 1,600 and 1,900°F. According to the EPA, these temperature restrictions make SNCR infeasible on small boilers because the necessary residence time within the appropriate temperature window cannot be achieved by boilers with heat input capacities below 100 MMBtu/hr.[38]

5.3.1.2 Step 2 - Technical Feasibility Assessment of Auxiliary Boiler NOx Control Alternatives

A review of the RBLC was conducted to identify and assess the emissions performance of available alternatives to control NOx emissions from small (<100 MMBtu/hr heat input capacity) natural gas-fired boilers. The RBLC search results are presented in Appendix E, Table E-7. A total of 109 natural gas-fired boilers with BACT limits for NOx in this size range were identified. The emission control alternative that is identified as BACT for NOx was included in 97 of these listings. LNBs or ULNBs (either alone or in combination with other alternatives) were identified as BACT for 92 listings, and SCR in combination with LNBs was identified for two listings.

Accordingly, LNBs, ULNBs, and SCR are all considered technically feasible emission control alternatives for the auxiliary boiler.

---

[37] EPA, *AP-42: Compilation of Air Pollutant Emissions Factors, Volume 1: Stationary Point and Area Sources*, at Sec. 1.4.4 (July 1998).

[38] 54 Fed. Reg. 24,792, 24,798 (June 9, 1989).

5.3.1.3 Steps 3-4 - Ranking and Effectiveness of Available Auxiliary Boiler NOx Control Alternatives

NOx emission limits for small natural gas-fired boilers listed in the EPA's RBLC range from 0.007 to 0.200 lb/MMBtu (see Appendix E, Table E-7). Thirty-one of the 109 RBLC listings for boilers in this category have emission limits equal to or less than 0.011 lb/MMBtu. All but two of these 31 listings identify either UNLBs or LNBs alone as the boiler's emission control system for NOx, including the listing with the lowest emission level (the auxiliary boiler at the CPV Towantic Power Plant near New Haven, CT). The other two of these listings describe the NOx control system as the exclusive use of natural gas as fuel and limitations in the permitted operating hours.

There are two RBLC listings for small boilers that describe the NOx control system as the use of SCR in combination with LNBs (Valero Delaware City Refinery in Delaware and Sabina Petrochemicals LLC in Texas). The permit limits for these listings, however (0.015 lb/MMBtu and 0.020 lb/MMBtu) are higher than other units that utilize ULNBs or LNBs to control NOx emissions.

Accordingly, ULNBs and LNBs are considered equivalent and representative of the top level of NOx controls for small boilers. Emission limits in the range of 0.007 to 0.011 lb/MMBtu (6 to 9 ppm at 3% O_2) have been concluded to be representative of BACT.

5.3.1.4 Step 5 - Evaluation of BACT for Auxiliary Boiler NOx Control

Alabama Power has not yet selected a vendor for the auxiliary boiler for this project, but the project specifications call for a boiler equipped with a LNB system capable of meeting a NOx emission limit of 0.011 lb/MMBtu (9 ppm at 3% O_2), which based on the results of the RBLC search is considered representative of BACT for an auxiliary boiler.

5.3.2 BACT for Carbon Monoxide and Volatile Organic Compound Emissions

BACT for CO and VOC are evaluated together in this section because the same alternatives are used to control emissions of both of these pollutants from small boilers.

As noted in Sections 5.2.2.1 and 5.2.3.1, CO and VOC emissions from combustion sources are a result of incomplete combustion of the carbon-containing compounds in the fuel. The primary factors that affect the formation and emission of CO and VOC from natural gas-fired boilers are the temperature of the boiler's combustion zone and the residence time of the fuel and combustion products within this zone. Higher combustion zone temperatures and longer residence times lead to more complete combustion and lower CO emissions.

5.3.2.1 Step 1 - Available Auxiliary Boiler CO and VOC Control Alternatives

A review of the RBLC was conducted to identify available alternatives to control CO and VOC emissions from small natural gas-fired boilers. The RBLC search results are presented in Appendix E, Tables E-8 and E-9.

A total of 101 units with BACT limits for CO in the same size range as the auxiliary boiler (<100 MMBtu/hr heat input) were identified. The emission control alternative that is identified as BACT for CO was included in 83 of these listings. Good combustion and burner design (i.e., ULNBs, LNBs, combustion control and/or good combustion practices) was identified as BACT for 69 of these listings. Use of an oxidation catalyst system was identified as BACT in two listings (Footprint Power in Salem, MA and the Marshalltown Generating Station in Marshalltown, IA). Use of flue gas recirculation or exhaust gas recirculation alone was identified as BACT in four listings, and the use of clean fuel or natural gas alone was identified in two listings.

Similarly, a total of 90 units with BACT limits on VOC emissions from small boilers were identified in the RBLC search. The alternative that was identified as BACT for VOC was included in 69 of these listings. As with CO, good combustion and burner design (58 listings), catalytic oxidation (one listing), flue gas recirculation or exhaust gas recirculation alone (four listings), and the use of clean fuel or natural gas alone (two listings) are the specific alternatives that are described as being used to control VOC emissions. An additional four listings describe “boiler operation in conformance with manufacturer’s specifications” as BACT.

Oxidation Catalyst

As described in Sections 5.2.2.2 and 5.2.3.2, an oxidation catalyst system is a post-combustion technology that removes CO and VOC from the exhaust gas of a combustion source. Such systems must be installed in an appropriate location within the tube passes of a boiler where the exhaust gas temperature is within the appropriate range, which varies depending on catalyst formulation. Further, effective oxidation catalyst control requires a limited space velocity across the surface of the catalyst and to limit pressure drop across the catalyst grid. For these reasons, there are few examples of the application of oxidation catalyst systems to control CO or VOC emissions from small natural gas-fired boilers.

Good Combustion and Burner Design

The fundamental design criteria for fuel burners is to maximize combustion efficiency, and thereby minimize the formation of products of incomplete combustion. Good combustion practices thus optimize combustion and heat liberation with specific burner design features (such as optimization of the combustion air-to-fuel ratio and promotion of complete air/fuel mixing) that results in minimization of CO and VOC formation.

5.3.2.2 Steps 2-4 - Technical Feasibility, Ranking and Effectiveness of Auxiliary Boiler CO and VOC Control Alternatives

Although the EPA’s RBLC contains very few examples of operating facilities that have employed catalytic oxidation to control CO or VOC emissions from small boilers, this alternative along with good combustion/burner design are concluded to be technically feasible alternatives for control of these pollutants from the proposed auxiliary boiler.

For small auxiliary boilers with oxidation catalysts, the lowest CO emissions level in the RBLC is 0.0035 lb/MMBtu for the auxiliary boiler at the new Footprint Power facility in Salem, MA. This facility, which was permitted in 2014 has only recently begun operation and information is not yet available to conclude that the permitted emission level on this boiler has been demonstrated.

The lowest VOC emissions level in the RBLC for small boilers where the emission control alternative is identified is 0.0017 lb/MMBtu for the auxiliary boiler at Black Hills Power’s Cheyenne Prairie Generating Station near Cheyenne, WY.

Good combustion practices and burner design features to ensure complete combustion have been concluded to be representative of BACT for most of the small boilers listed in the RBLC with limits on CO. For CO, the emission limits for these measures in the RBLC listings is from 0.0075 to 0.25 lb/MMBtu, with majority of the listings having limits below 0.040 lb/MMBtu. Of the 42 small boilers included in the RBLC that were permitted within the past 5 years, 19 have CO limits below 0.040 lb/MMBtu, with 15 listings having emission limits between 0.030 and 0.040 lb/MMBtu.

Good combustion practices and/or burner design features to ensure complete combustion have also been concluded to be representative of BACT for most of the small boilers listed in the RBLC with limits on VOC. For VOC, the emission limits in the RBLC listings where the emission control technology is identified range from 0.0017 to 0.054 lb/MMBtu. The lowest emission level from among these listings (for the 25 MMBtu/hr auxiliary boiler at the Cheyenne Prairie Generating Station in Wyoming) describes good combustion as BACT for VOC. A total of 34 boilers are listed as having been permitted within the past 5 years; 21 of these have VOC limits below 0.0060 lb/MMBtu, and ten have emissions limits between 0.0030 and 0.0050 lb/MMBtu.

5.3.2.3 Step 5 - Evaluation of BACT for Auxiliary Boiler CO and VOC Control

For the proposed natural gas-fired auxiliary boiler, good combustion practices and burner design is concluded to be representative of BACT for control of CO and VOC emissions from this unit. As noted in Section 5.3.1.4, Alabama Power has not yet selected a vendor for the auxiliary boiler for this project. However the project specifications call for a boiler to be used that will meet a CO emission level of 0.037 lb/MMBtu and a VOC emissions level of 0.004 lb/MMBtu; these emission levels are proposed as BACT for CO and VOC emissions (respectively) for the auxiliary boiler, which is in range of recent typical BACT determinations of units of similar size as provided in Section 5.3.2.2 and summarized in Appendix E, Tables E-8 and E-9.

5.3.3 BACT for Particulate Matter Emissions

As with particulate matter from combustion turbines, particulate matter emissions from natural gas-fired boilers consist of both filterable and condensable (back-half) particles. The following subsections present the BACT assessment for particulate matter (including total PM, PM10, and PM2.5) emissions from the proposed natural gas-fired auxiliary boiler.

5.3.3.1 Step 1 - Available PM, PM_{10} and $PM_{2.5}$ Auxiliary Boiler Control Alternatives

EPA concluded that uncontrolled particulate matter emissions from small natural gas-fired boilers are very low. As a consequence, the Agency concluded at the time the NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (i.e., 40 CFR 60, Subpart Dc) were proposed that application of add-on particulate matter controls to small natural gas-fired units would impose significant costs, and that "…the use of any conventional PM control technology to reduce PM emissions from small natural gas-fired steam generating units is considered unreasonable…"[39]

A review of the RBLC was conducted to identify available particulate matter control alternatives for natural gas-fired boilers. The RBLC search results are presented in Appendix E, Table E-10. A total of 54 natural gas-fired boilers with heat inputs less than 100 MMBtu/hr with BACT limits for particulate matter were identified. The particulate matter emission control alternative identified as BACT was included in 43 of these listings. Equipment design, combustion control and/or good combustion practices (either alone or in conjunction with the use of clean fuels) were identified as BACT for 29 of these listings. Use of clean (low sulfur, low ash) fuels alone was identified as BACT for 14 listings.

5.3.3.2 Steps 2-4 - Technical Feasibility Assessment and Ranking of Auxiliary Boiler PM Control Alternatives

Boiler design, combustion control and the use of clean fuels are the only feasible and most stringent alternatives for control of particulate matter from the proposed auxiliary boiler. Add-on particulate matter control systems are not technically feasible on natural gas-fired boilers.

---

[39] *Id.*

5.3.3.3 Step 5 - Evaluation of BACT for Auxiliary Boiler PM Control

The most stringent particulate matter control method demonstrated for small natural gas-fired boilers is the use of combustion controls in conjunction with the firing of clean fuel (such as natural gas). Accordingly, the boiler design and combustion controls in conjunction with the exclusive firing of natural gas is concluded to be representative of BACT for control of $PM/PM_{10}/PM_{2.5}$ emissions from the proposed auxiliary boiler. These measures will limit particulate matter emissions to 0.0075 lb/MMBtu of PM_{10} or $PM_{2.5}$.

5.3.4 BACT for Sulfur Dioxide Emissions

As described in Section 5.2.5, SO_2 emissions from combustion sources occur as a result of oxidation of sulfur-containing compounds in the fuel. Combustion units that utilize low-sulfur fuels such as natural gas will have correspondingly low SO_2 emissions.

5.3.4.1 Steps 1 - 4 – Technical Feasibility Assessment and Ranking of Auxiliary Boiler SO_2 Emissions Control Alternatives

When standards of performance for small boilers were proposed under the NSPS program, EPA declined to establish SO_2 emission limits for natural-gas fired units because of the low uncontrolled emission levels associated with them[40]. As with natural gas-fired combined cycle units, the use of FGD is not technically feasible on natural gas-fired boilers because the SO_2 emissions from these units are less than the outlet emission rates that have been achieved on other combustion sources using FGD. Consequently, the only technically feasible alternative to control SO_2 emissions from the auxiliary boiler is the exclusive firing of natural gas in the unit.

A review of the RBLC was conducted to identify available alternatives to control SO_2 emissions from small natural gas-fired boilers. The RBLC search results are presented in Appendix E, Table E-11. A total of 53 natural gas-fired boilers with BACT limits for SO_2 were identified. The emission control alternative that is identified as BACT for SO_2 was included in 42 of these listings. The use of natural gas or clean fuel was identified as BACT for 39 listings, and good combustion practices was identified as BACT for 12 listings. As evidenced by these listings, the exclusive firing of natural gas is the top-level alternative for control of SO_2 emissions from small natural gas-fired boilers.

5.3.4.2 Step 5 - Evaluation of BACT for Auxiliary Boiler SO_2 Emissions Control

Table E-11 of Appendix E shows that the SO_2 emission rates from small natural gas-fired boilers listed in EPA's RBLC vary from 0.0005 to 0.0257 lb/MMBtu depending on the sulfur content of the gas. Based on projected worst-case natural gas sulfur content of 0.6 gr S/100 scf, the SO_2 emission rate from the proposed auxiliary boiler will be 0.15 lb/hr (0.00168 lb/MMBtu). The exclusive firing of natural gas in the auxiliary boiler is proposed as BACT for control of SO_2 emissions from this unit.

5.3.5 BACT for GHG Emissions

5.3.5.1 Step 1 - Available GHG Auxiliary Boiler Control Alternatives

There is currently no technically feasible add-on control technology to reduce GHG emissions from the auxiliary boiler. A search of the RBLC was conducted to identify recently-permitted small natural gas-fired boilers with BACT determinations for GHGs. The results of this search are provided in Appendix E, Table E-12. A total of 52 small natural gas-fired boilers that meet these criteria were identified. The measures concluded to be representative of BACT are described in 42 of these

---

[40] *Id.* at 24,804.

listings, and include the use of lower carbon-emitting fuels (22 listings), or efficient boiler design and GCP (34 listings).

5.3.5.2 Steps 2 and 3 - GHG Technical Feasibility

Efficient boiler design, cleaner fuels, and GCP are all technically feasible to control GHG emissions from natural gas-fired boiler. For the purposes of this BACT analysis, efficient boiler design, cleaner fuels, and GCP are being considered together.

5.3.5.3 Steps 4 and 5 - Proposed GHG Emissions Limits

Since efficient boiler design, cleaner fuels, and GCP are being considered in concert, ranking the effectiveness of each is not necessary. Alabama Power is proposing the use of efficient boiler design, cleaner fuels, and GCP as BACT for the auxiliary boiler.

5.4 BACT for Emergency Diesel Generators and Fire Water Pump Engine

5.4.1 BACT for Nitrogen Oxides, Carbon Monoxide and Volatile Organic Compound Emissions

BACT for CO, NOx and VOC are evaluated together in this section because the principal means to control their emissions from emergency diesel engines is common for all three pollutants, as described further below.

NOx formation mechanisms for combustion sources are discussed in Section 5.2.1.1. As with other fuel combustion sources, CO and VOC emissions from emergency diesel engines are the result of incomplete combustion of the carbon-containing compounds in the fuel. CO and VOC emission rates from diesel engines are influenced by engine design and operational features which promote energy efficiency and complete fuel combustion.

5.4.1.1 Steps 1-2 - Available Technically-Feasible Emergency Diesel Engine Control Alternatives for NOx, CO, and VOC

EPA began regulating NOx, CO and VOC emissions from diesel engines with the promulgation of the first tier of emission standards for mobile source non-road engines in 1994 under 40 CFR Part 89. Under these requirements, “volatile organic compounds” are referred to as “non-methane hydrocarbons” or NMHC. In the following discussions, NMHC shall hereinafter be referred to as VOC.

The NSPS for stationary diesel engines (40 CFR Part 60, Subpart IIII), including emission standards for NOx, CO, and VOC, were proposed in July 2005. At that time, EPA noted that the emission control strategies that were chosen for the non-road engine standards were appropriate for stationary diesel engines as well, because engine manufacturers stated that they generally do not design and manufacture separate diesel engines for mobile and stationary use[41]. EPA identified two types of emission controls for NOx, CO and VOC from stationary diesel engines when 40 CFR Part 60, Subpart IIII standards were proposed: engine-based technologies and aftertreatment-based technologies. Engine-based technologies include inlet air cooling, fuel injection rate controls, injection timing retard, exhaust gas recirculation, control of air/fuel ratio, and control of air consumption. Collectively, these alternatives are referred to as engine design, combustion controls, and good combustion practices.

[41] 70 Fed. Reg. 39,870, 39,882 (July 11, 2005)

The aftertreatment technologies that form the basis for the non-emergency Tier 4 non-road engine emission standards is the use of SCR for NOx control and catalyzed diesel particulate filters (CDPF) used in conjunction with ultra-low sulfur diesel fuel. In a CDPF, a catalyst material is applied to a solid metal particulate filter to promote chemical reactions between gas-phase components of engine exhaust and soot particles that are collected in the filter. The purpose of the catalyst is to facilitate regeneration of the filter by promoting oxidation of the soot particles at the normal operating temperature of the engine's exhaust system.

When promulgating 40 CFR Part 60, Subpart IIII, EPA reaffirmed its conclusion in the proposed rule that the use of engine-based technologies to meet the Tier 2 or Tier 3 engine standards, rather than the aftertreatment technologies that constitute Tier 4 controls, represent the best demonstrated technology for controlling emissions from emergency stationary diesel engines and emergency fire pump engines. The Agency concluded that standards based on the use of aftertreatment technologies (CDPF, oxidation catalyst, or post-combustion NOx controls) were not justifiable for emergency stationary engines or emergency fire pumps "…due to the cost of the technology relative to the emission reduction that would be obtained."[42] Accordingly, engine design, combustion controls, and good combustion practices are considered available alternatives for control of NOx, CO and VOC from emergency stationary diesel engines.

A review of the RBLC was conducted to identify available alternatives to control NOx, CO and VOC emissions from emergency stationary diesel engines in the same size ranges as for the planned emergency generators (1,500 kw or 2010 hp) and emergency fire water pump engine (316 hp). The RBLC search results are presented in Appendix E, Tables E-13, E-14, and E-15.

Four RBLC listings for emergency diesel engines describe the use of EPA Tier IV emission controls as representative of BACT. Emergency diesel engines are not required to meet Tier IV emission limits, so the emission controls listed for these engines are not considered representative for this category of engines. The emission control alternatives identified for the remaining listings in the RBLC review are summarized in the following table.

Table 5-3: Summary of EPA RBLC Listings for Emergency Stationary Diesel Engines

	NOx Listings	CO Listings	VOC Listings
Total Listings	184	169	121
Listings with control technologies identified	136	132	97
Engine design or certification	76	80	43
Good combustion	78	76	56
Clean fuels/ULSD	25	22	18
Operating hours limitation	29	20	16

Apart from the four listings noted above, none of the RBLC listings that describe what controls were concluded to be BACT list the use of aftertreatment controls (CDPF, oxidation catalyst systems, or

[42] *Id.* at 39,874.

post-combustion NOx controls) as BACT for NOx, CO, or VOC for emergency stationary diesel engines.

Because CDPF and oxidation systems impose backpressure on the engine's exhaust system, they are only technically feasible on engines that are specifically designed for their use, and they are generally not technically feasible for retrofit situations.

EPA updated or amended the 40 CFR 60, Subpart IIII standards a total of four times since they were originally promulgated in 2006. The original NSPS emission limits for emergency stationary diesel engines and emergency stationary fire pump engines, however, have not changed. Accordingly, the use of engine-based technologies can be concluded as the only technically-feasible means to control NOx, CO, and VOC emissions from emergency stationary diesel engines and emergency stationary fire pump engines.

5.4.1.2 Steps 3-4 - Ranking of Emergency Diesel Engine NOx, CO, and VOC Control Alternatives

The use of engine-based emission control technologies for emergency engines (engine design, combustion controls, and good combustion practices) are the only available controls, and therefore they are the most stringent alternative for control of NOx, CO and VOC from the proposed diesel engines serving the emergency generators and emergency fire water pump engines.

5.4.1.3 Step 5 - Evaluation of BACT for Emergency Diesel Engine NOx, CO, and VOC Control

As the most stringent available alternative for emissions control from emergency diesel engines, the use of engine-based controls (engine design, combustion controls, and good combustion practices) is concluded to be representative of BACT for control of NOx, CO and VOC emissions from the proposed emergency generators and fire water pump engine. These measures will serve to limit emissions from these engines to the NSPS Subpart IIII emission limits, which are summarized in Table 5-4.

Table 5-4: NSPS Subpart IIII Limits

	Emergency Generators	Emergency Fire Pump Engine
NMHC + NOx	4.8 g/bhp-hr	3.0 g/bhp-hr
CO	2.6 g/bhp-hr	2.6 g/bhp-hr

As required by 40 CFR 60, Subpart IIII, the diesel engines serving the emergency generators and emergency fire water pump engine are required to be certified by the manufacturer that they meet these emissions levels.

5.4.2 BACT for Particulate Matter Emissions

Particulate matter emissions from diesel engines consist of inorganic matter present in the fuel (ash, metal oxides, etc.), sulfate resulting from fuel sulfur combustion, and high molecular weight unburned hydrocarbons (soot). Both filterable and condensable particulate matter fractions are emitted from diesel engines. Generally, the use of clean (low sulfur, low ash) fuels in conjunction with engine design and operational features to promote complete fuel combustion minimizes particulate matter emissions from diesel engines.

5.4.2.1 Step 1 - Available Emergency Diesel Engine PM Control Alternatives

As described in Section 5.4.1.1, when EPA promulgated the NSPS Subpart IIII emissions standards, it identified engine-based technologies as BDT to reduce emissions (including particulate matter emissions) from emergency stationary diesel engines and emergency fire pump engines. These alternatives are considered generally available for control of particulate matter from the proposed emergency diesel engines.

A review of the RBLC was conducted to augment identified alternatives to control particulate matter emissions from emergency diesel engines. The RBLC search results are presented in Appendix E, Table E-16. A total of 113 emergency diesel engines with BACT limits for particulate matter were identified. The emission control alternative identified as BACT for particulate matter was included in 86 of these listings. Engine design, combustion control and/or good combustion practices were identified as BACT for 67 of these listings, use of low sulfur fuel alone was identified as BACT for 7 listings, and a limitation on annual operating hours alone was identified as BACT for an additional listing. The use of CDPF was identified as BACT for four listings, all for emergency diesel engines planned for the Marshall Energy Center near Battle Creek, MI. This facility has not yet been constructed, and thus whether this technology is technically feasible on intermittently operated emission sources (such as emergency generators or emergency fire pump engines) has not yet been demonstrated. Moreover, the emission limits for these four listings (0.15 g/hp-hr) are consistent with the 40 CFR60, Subpart IIII requirements for emergency engines, even though emergency engines are not required to use Tier 4 emission control equipment, such as CDPF.

5.4.2.2 Steps 2-4 - Technical Feasibility Assessment and Ranking of Diesel Engine PM Control Alternatives

As noted previously, the emergency generators and diesel fire water pump engine planned for the Project will operate on an intermittent basis in emergency situations. In conformance with NSPS Subpart IIII requirements, the emergency generators will utilize a Tier 2 engine and the fire water pump will utilize a Tier 3 engine. Tier 2 and Tier 3 engines are not designed to be used with CDPF systems, and the use of such particulate filters has not been yet been demonstrated to be technically feasible on emergency generator or emergency fire pump engines. Accordingly, the use of ultra-low sulfur and low ash fuel, engine design, and operating hours limitations are considered the most stringent alternatives for control of PM from the emergency diesel engines.

5.4.2.3 Step 5 - Evaluation of BACT for Emergency Diesel Engine PM Control

Particulate matter emissions from the emergency diesel engines will be limited through the use of ultra-low sulfur, low ash fuel (0.0015% S distillate oil) and annual use limitations. The emergency generators and the emergency fire pump engine will be operated for emergency purposes. Accordingly, the emission limits in 40 CFR 60, Subpart IIII that are applicable for these units (0.15 g/bHP-hr) are considered representative of BACT for particulate matter.

5.4.3 BACT for Sulfur Dioxide Emissions

Sections 5.2.5 and 5.3.4 describe how SO_2 emissions from combustion sources are the result of oxidation of sulfur-containing compounds in the fuel, and that units which fire low-sulfur fuels have low SO_2 emissions.

5.4.3.1 Steps 1 - 4 - Technical Feasibility Assessment and Ranking of Emergency Diesel Engine SO_2 Emission Control Alternatives

EPA declined to establish emission limits for SO_2 from emergency diesel engines when the new source performance standards for units in this category (i.e., 40 CFR 60 Subpart IIII) were proposed.

At the time, the agency explained that limits on SO_2 emissions from diesel engines were not warranted because the recent revisions to the transportation diesel fuel standards - adoption of ultra-low sulfur diesel fuel requirements - would result in decreases in SO_2 emissions from these units[43].

A review of the RBLC was conducted to identify available alternatives to control SO_2 emissions from emergency diesel engines. The RBLC search results are presented in Appendix E, Table E-17. A total of 71 engines with BACT limits for SO_2 were identified. The emission control alternative that is identified as BACT for SO_2 was included in 49 of these listings. The use of ultra-low sulfur diesel (ULSD) fuel containing no more than 15 ppm sulfur was identified as BACT for 39 listings of these listings; good combustion practices was identified as BACT for 13 listings. Post-combustion SO_2 control alternatives, including FGD, are not technically feasible on diesel engines because SO_2 emissions from diesel engines are lower than the outlet emission rates that have been achieved on other combustion sources using post-combustion controls. Accordingly, it can be concluded that the firing of low sulfur diesel fuel is the only technically feasible alternative for control of SO_2 emissions from emergency diesel engines, and the firing of ULSD is the top-level control alternative.

5.4.3.2 Step 5 - Evaluation of BACT for Emergency Diesel Engine SO_2 Emissions Control

As the top-level SO_2 emissions control alternative for emergency diesel engines, the exclusive use of ULSD is proposed as BACT for control of SO_2 emissions from the emergency generators and emergency fire water pump.

5.4.4 BACT for GHG Emissions

5.4.4.1 Step 1 - Available Emergency Diesel Engine GHG Control Alternatives

There are currently no technically feasible add-on control alternatives to reduce GHG emissions from the fire water pump and emergency generator engines. A search of the RBLC was conducted to identify recently-permitted emergency diesel engines with BACT determinations for GHGs. The results of this search are provided in Appendix E, Table E-18. A total of 138 emergency diesel engines that meet these criteria were identified. The measures concluded to be representative of BACT, described in 102 of these listings, include use of low carbon fuels (9 listings) and incorporating GCP or efficient combustion (97 listings).

5.4.4.2 Steps 2-5 - Technical Feasibility Assessment, Ranking, and Evaluation of Diesel Engine GHG Control Alternatives

As the only technically-feasible alternative to limit GHG emissions from emergency diesel engines, Alabama Power concludes that the use of GCP meeting applicable NSPS and MACT standards, are representative of BACT.

The engines will be maintained in accordance with the manufacturer's specifications.

5.5 BACT for Cooling Tower Particulate Matter Emissions

Particulate matter emissions from cooling towers are emitted as a result of the discharge of liquid water droplets containing dissolved solids being entrained the air stream leaving the unit (called "drift"). When the water evaporates, the dissolved solid constituents remain, resulting in solid particles becoming air emissions. Only filterable particulate matter is emitted from cooling towers.

---

[43] *Id.* at 39,879.

5.5.1 Step 1 - Available Cooling Tower PM Control Alternatives

A review of the RBLC was conducted to identify available PM, PM10 and PM2.5 control measures for cooling towers. This search, the results of which are presented in Appendix E Table E-19, identified a total of 27 cooling tower listings. The emission control method was identified in all of these listings, and each listing identified the use of drift eliminators as BACT; three listings identified restrictions in the total dissolved solids (TDS) content of the cooling tower recirculation water as an additional control measure.

5.5.2 Steps 2-4 - Technical Feasibility Assessment and Ranking of Cooling Tower PM Control Alternatives

Drift eliminators consist of baffles located at the top of a cooling tower that are designed to prevent water droplets from escaping the tower by causing the droplets to change direction and lose velocity, and by impaction on the baffle blades resulting in agglomeration of droplets. Drift eliminators are the only available and most stringent means to minimize particulate matter emissions from cooling towers.

5.5.3 Step 5 - Evaluation of BACT for Cooling Tower PM Control

Alabama Power will utilize drift eliminators on the new cooling towers proposed for the Project. The cooling towers will have a maximum drift rate equal to 0.0005% of the recirculated water flow. This is the only available and most stringent alternative to control particulate matter emissions from cooling towers and is, therefore, concluded to be representative of BACT.

5.6 Summary of Proposed BACT

Table 5-5 summarizes the proposed BACT limits and compliance demonstration methods for each of the project's proposed emission units. The proposed BACT emission limits are only applicable during periods of normal operation.

Table 5-5: Proposed BACT Emission Limits and Compliance Demonstration Methods

	Proposed Emission Limits	Compliance Demonstration Methods
Combined Cycle Units (per unit)		
Nitrogen Oxides	39.1 lb/hr[1]	EPA Reference Method 7 or 7E
Carbon Monoxide	23.8 lb/hr[1]	EPA Reference Method 10
Volatile Organic Compounds	13.6 lb/hr[1]	EPA Reference Method 25, 25A, or 25B
Particulate matter (PM10/PM2.5)	21.51 lb/hr	EPA Reference Method 5, 17 or 201 and 202
Sulfur Dioxide	Natural gas firing exclusively	
Greenhouse Gases (CO_2e)	2,445,022 ton/yr	CEMS, Fuel Use Monitoring

	Proposed Emission Limits	Compliance Demonstration Methods
Auxiliary Boiler		
Nitrogen Oxides	0.011 lb/MMBtu	EPA Reference Method 7 or 7E
Carbon Monoxide	0.037 lb/MMBtu	EPA Reference Method 10
Volatile Organic Compounds	0.004 lb/MMBtu	EPA Reference Method 25, 25A, or 25B
Particulate matter (PM10/PM2.5)	0.0075 lb/MMBtu	EPA Reference Method 5 or 17
Sulfur Dioxide	Natural gas firing exclusively	
Cooling Tower		
Particulate matter PM (filterable)	Maximum drift limited to 0.0005% of the recirculated water flow	N/A
Emergency Diesel Generator (per unit)		
Non-methane Hydrocarbons + Nitrogen Oxides	4.8 g/bhp-hr	EPA Certificate of Conformity
Carbon Monoxide	2.6 g/bhp-hr	EPA Certificate of Conformity
Particulate matter PM (filterable)	0.15 g/bhp-hr	EPA Certificate of Conformity
Sulfur Dioxide	Ultra-low sulfur diesel fuel firing exclusively	
Emergency Diesel Fire Water Pump		
Non-methane Hydrocarbons + Nitrogen Oxides	3.0 g/bhp-hr	EPA Certificate of Conformity
Carbon Monoxide	2.6 g/bhp-hr	EPA Certificate of Conformity
Particulate matter PM (filterable)	0.15 g/bhp-hr	EPA Certificate of Conformity
Sulfur Dioxide	Ultra-low sulfur diesel fuel firing exclusively	

[1] The proposed pound per hour emissions rates are based on a concentration of 2 ppm @ 15% O2, consistent with the vendor guarantee under normal operating conditions

6.0 Class II Area Air Quality Modeling Analysis Procedures

This section presents the approach to the dispersion modeling analysis that was conducted to assess compliance with the applicable state and federal ambient air quality regulations and guidelines. The analyses were conducted in accordance with ADEM's March 2019 Draft PSD Air Quality Analysis Modeling Guidelines[44] (ADEM's Modeling Guidelines), and EPA's Guideline on Air Quality Models (GAQM, which is contained in 40 CFR Part 51, Appendix W) (EPA 2017). The following sections present the source data that was modeled, the procedure used for assessing ambient air impacts from the proposed Project's emissions and the standards to which the predicted impacts were compared against.

Based on preliminary emission estimates, the proposed Project will be subject to PSD review for VOC, CO, NO_2, SO_2, PM_{10}, $PM_{2.5}$, and GHG. Modeling analyses were performed to evaluate compliance with applicable PSD increments and NAAQS for these pollutants, except for VOC and GHG emissions as there are no modeling requirements for these pollutants. The modeling analysis also addresses impacts associated with secondary $PM_{2.5}$ and ozone as described further in Section 6.8.

The dispersion modeling for this Project was conducted in a manner that utilizes the Project's worst-case operating conditions associated with the ambient temperature range which emissions were evaluated in order to predict the highest concentration for each pollutant and averaging period.

ADEM has defined a set of concentrations (called significant impact levels, or SILs) used to determine whether a major new source or major modification of an existing major source will "significantly" impact a Class II area (ADEM Admin. Code r. 335-3-14-.03(1)(g) and ADEM's Modeling Guidelines). Significant impact levels represent the maximum amount of ambient impact below which no further analysis of major new source impacts is required (see values listed in Table 6-1). With the exception of $PM_{2.5}$, ADEM's SILs are the same SILs that EPA has promulgated under 40 CFR §51.165(b)(2). Where ADEM's SILs are not the same as EPA's SILs, ADEM's SILs were used for this analysis.

For those pollutants which have modeled concentrations at or below the applicable SIL, no additional analysis was performed since, by definition, the pollutant can be reasonably assumed not to cause or contribute to a NAAQS violation or an exceedance of a PSD increment. If modeling indicated that SILs for some pollutants and averaging periods are exceeded, then a cumulative impact modeling assessment was performed. The results of the cumulative modeling were compared to the NAAQS and PSD increments (see Table 6-1), as applicable.

All model input and output files are included with this application submittal to ADEM in the modeling archive contained in Appendix G.

[44] ADEM, *PSD Air Quality Analysis Modeling Guidelines* (Mar. 2019), http://www.adem.state.al.us/programs/air/airquality/AeromodModelingGuidelines.pdf.

Table 6-1: Allowable PSD Increments and Significant Impact Levels, (µg/m^3)

Pollutant	Averaging Time	PSD Increments		SILs		NAAQS
		Class I	Class II	Class I[3]	Class II	
PM_{10}	Annual Arithmetic Mean[1]	4	17	0.2	1	NA
	24-hour Maximum[2]	8	30	0.3	5	150
$PM_{2.5}$[5]	Annual Arithmetic Mean[1]	1	4	0.06	0.3	12
	24-hour Maximum[2]	2	9	0.07	1.2	35
SO_2	Annual Arithmetic Mean[1]	2	20	0.1	1	NA
	24-hour Maximum[2]	5	91	0.2	5	NA
	3-hour Maximum[2]	25	512	1	25	1300
	1-hour Maximum[4]	NA	NA	NA	7.86	196
CO	8-hour Maximum	NA	NA	NA	500	10,000
	1-hour Maximum	NA	NA	NA	2000	40,000
NO_2	Annual Arithmetic Mean[1]	2.5	25	0.1	1	100
	1-hour Maximum[4]	NA	NA	NA	7.5	189

[1] PSD Increment not to be exceeded
[2] PSD Increment not to be exceeded more than once per year
[3] Class I SILs were proposed in FR July 23, 1996
[4] While there are no EPA promulgated SILs for the 1-hour SO_2 and NO_2 NAAQS, interim SIL values have been provided for Class II areas.
[5] SILs for $PM_{2.5}$ exist for the purpose of determining if a source has a significant contribution to a modeled violation. The SILs do not exist for the purposes of avoiding a cumulative impact analysis.
Notes: NA = Not applicable, i.e., no increment exists.

6.1 Modeling Source Approach and Configurations

The air dispersion modeling analysis was conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) that represent the worst-case parameters among the range of possible values considered for the proposed Project. This includes the vendor proposed turbine upgrade as part of the Project. There are slight variations in emission rates and flue gas exhaust characteristics between the “pre” and “post” upgrade configuration of the combined-cycle (CC). The modeling analyses conducted for this application accounted for the turbine’s performance under both the pre- and post-upgrade configurations.

6.1.1 Combined Cycles Pre- and Post-Upgrade

Based on current Project design parameters, Alabama Power is applying for a permit that allows unrestricted annual operation (8,760 hours per year) of two CC units.

Since emission rates and flue gas characteristics for a given operating load vary as a function of ambient temperature, data was derived for the following ambient temperatures and load scenarios for both the pre- and post-upgrade cases:

- 5 operating loads (Base load [or 100% Load] with duct burner firing (DB) and inlet conditioning (IC), Base load [or 100% Load] with IC and no DB, Base load [or 100% Load] with no DB and no IC, 75% load, 50% load)
- 8 ambient temperatures (105°F, 94°F, 67°F, 59°F, 30°F, 28°F, 20°F, 0°F)

A summary of the pre- and post-upgrade exhaust data and emission rates for each ambient temperature and operating load is provided in Tables 6-2 and 6-3 respectively.

In order to conservatively calculate ground-level concentrations, a composite “worst-case” set of emission rates and exhaust parameters was used in the modeling in an initial approach for both the pre- and post-upgrade cases. For each CC unit operating load, the highest pollutant-specific emission rate coupled with the lowest exhaust temperature and exhaust flow rate was selected. Tables 6-4 and 6-5 summarize the worst-case emission parameters for the pre- and post-upgrade operating loads, respectively.

This data was used to perform a load analysis (as described in Section 7.1) for the two CC units alone for both the pre- and post-upgrade configurations. The worst-case load scenario between the pre- and post-upgrade cases for each pollutant and averaging period was used in the subsequent SIL, NAAQS and PSD increment modeling, as applicable.

Table 6-2: Stack Exhaust Parameters and Emission Rates: Pre-Upgrade Configuration

Scenario[1]	Ambient Temp. (˚F)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr/CC) [2],[3]				
						NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2
100% + IC + DB	105	180	23	[redacted]						
100% + IC + DB	94	180	23							
100% + IC + DB	67	180	23							
100% + IC + DB	59	180	23							
100% + DB[4]	30	180	23							
100% + DB[4]	28	180	23							
100% + DB[4]	20	180	23							
100% + DB[4]	0	180	23							
100% + IC w/o DB	105	180	23							
100% + IC w/o DB	94	180	23							
100% + IC w/o DB	67	180	23							
100% + IC w/o DB	59	180	23							
100% w/o IC w/o DB	105	180	23							
100% w/o IC w/o DB	94	180	23							
100% w/o IC w/o DB	67	180	23							
100% w/o IC w/o DB	59	180	23							
100% w/o IC w/o DB	30	180	23							
100% w/o IC w/o DB	28	180	23							
100% w/o IC w/o DB	20	180	23							
100% w/o IC w/o DB	0	180	23							
75%	105	180	23							
75%	94	180	23							
75%	67	180	23							
75%	59	180	23							
75%	30	180	23							
75%	28	180	23							
75%	20	180	23							
75%	0	180	23							
50%	105	180	23							
50%	94	180	23							
50%	67	180	23							
50%	59	180	23							
50%	30	180	23							
50%	28	180	23							
50%	20	180	23							
50%	0	180	23							

Note: Data are provided per emission units unless otherwise noted.

(1) Data presented are for multiple operating loads/conditions and eight ambient temperatures.
(2) Hourly emissions reflect operation of a single CC unit (pre-upgrade) firing natural gas only.
(3) Bold italicized numbers indicate highest emissions, lowest temperature, and lowest exhaust over the ambient temperatures.
(4) Inlet conditioning will only be operated at ambient temperatures above 59°F.

Table 6-3: Stack Exhaust Parameters and Emission Rates: Post-Upgrade Configuration

Scenario[1]	Ambient Temp. (˚F)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr/CC) [2],[3]				
						NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2
100% + IC + DB	105	180	23	[redacted]						
100% + IC + DB	94	180	23							
100% + IC + DB	67	180	23							
100% + IC + DB	59	180	23							
100% + DB[4]	30	180	23							
100% + DB[4]	28	180	23							
100% + DB[4]	20	180	23							
100% + DB[4]	0	180	23							
100% + IC w/o DB	105	180	23							
100% + IC w/o DB	94	180	23							
100% + IC w/o DB	67	180	23							
100% + IC w/o DB	59	180	23							
100% w/o IC w/o DB	105	180	23							
100% w/o IC w/o DB	94	180	23							
100% w/o IC w/o DB	67	180	23							
100% w/o IC w/o DB	59	180	23							
100% w/o IC w/o DB	30	180	23							
100% w/o IC w/o DB	28	180	23							
100% w/o IC w/o DB	20	180	23							
100% w/o IC w/o DB	0	180	23							
75%	105	180	23							
75%	94	180	23							
75%	67	180	23							
75%	59	180	23							
75%	30	180	23							
75%	28	180	23							
75%	20	180	23							
75%	0	180	23							
50%	105	180	23							
50%	94	180	23							
50%	67	180	23							
50%	59	180	23							
50%	30	180	23							
50%	28	180	23							
50%	20	180	23							
50%	0	180	23							

Note: Data are provided per emission units unless otherwise noted.

(1) Data presented are for multiple operating loads/conditions and eight ambient temperatures.
(2) Hourly emissions reflect operation of a single CC unit (post-upgrade) firing natural gas only.
(3) Bold italicized numbers indicate highest emissions, lowest temperature, and lowest exhaust over the ambient temperatures.
(4) Inlet conditioning will only be operated at ambient temperatures above 59°F.

Table 6-4: Composite Worst-Case Data (1) Modeling Inputs: Pre-Upgrade Configuration

Parameter		Value				
Load (%)		**100% + IC + DB**	**100% + IC w/o DB**	**100% w/o IC w/o DB**	**75%**	**50%**
Stack Height (ft)		180	180	180	180	180
Stack Diameter (ft)		23	23	23	23	23
Exit Temperature (°F)						
Exit Velocity (ft/sec)						
Pollutant Emissions Per CC Unit (lb/hr/CC)	**SO_2**	8.02	6.19	6.44	5.55	4.17
	PM_{10}	21.08	13.86	14.31	12.61	9.89
	$PM_{2.5}$	21.08	13.86	14.31	12.61	9.89
	NO_X	38.0	29.2	30.3	26.1	19.5
	CO	23.1	17.8	18.5	15.9	11.9

Note: Data are provided per emission unit unless otherwise noted.

(1) The values in the table represent the worst-case stack parameters and the emission rates for the five operating loads taken from Table 6-2 (bold and italicized)

Table 6-5: Composite Worst-Case Data (1) Modeling Inputs: Post-Upgrade Configuration

Parameter		Value				
Load (%)		**100% + IC + DB**	**100% + IC w/o DB**	**100% w/o IC w/o DB**	**75%**	**50%**
Stack Height (ft)		180	180	180	180	180
Stack Diameter (ft)		23	23	23	23	23
Exit Temperature (°F)						
Exit Velocity (ft/sec)						
Pollutant Emissions Per CC Unit (lb/hr/CC)	**SO_2**	8.21	6.62	6.70	5.96	4.46
	PM_{10}	21.51	14.64	14.93	13.39	10.52
	$PM_{2.5}$	21.51	14.64	14.93	13.39	10.52
	NO_X	39.1	31.5	31.8	28.3	21.0
	CO	23.8	19.2	19.4	17.2	12.8

Note: Data are provided per emission unit unless otherwise noted.

(1) The values in the table represent the worst-case stack parameters and the emission rates for the five operating loads taken from Table 6-3 (bold and italicized)

6.1.2 Ancillary Sources

The project will also consist of an auxiliary boiler. Because the performance data for the auxiliary boiler is not expected to be affected by ambient conditions, only one set of parameters was modeled (e.g., stack parameters and emission rates associated with 100% load). The auxiliary boiler was modeled at 8,760 hours/year. Thus, the emission rates in Table 6-6 are for both short term and annual modeling.

Table 6-6: Source Parameters and Criteria Pollutant Emission Rates for the Auxiliary Boiler

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr/unit)				
					NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2
AUXBLR8	70.0	3.5	309	65.0	1.00	3.35	0.68	0.68	0.152

6.2 Model Selection and Options

The suitability of an air quality dispersion model for a particular application is dependent upon several factors. The following selection criteria were evaluated:

- dispersion environment;
- stack height relative to nearby structures;
- local terrain; and
- representative meteorological data.

The EPA GAQM prescribes a set of approved models for regulatory applications for a wide range of source types and dispersion environments. AERMOD is EPA's recommended refined dispersion model for simple and complex terrain for receptors within 50 kilometers (km) of a modeled source and is capable of handling the source geometry, terrain, and dispersion environment associated with this Project. In addition, there is representative meteorological data available with suitable data capture for parameters needed to run AERMOD.

As such, based on a review of the factors described in the following sections, Alabama Power has used the latest version of AERMOD (19191) (EPA 2019a) to assess air quality impacts for the Project. AERMOD was used to assess air quality concentrations associated with Project emissions of NO_2, SO_2, CO, PM_{10}, and $PM_{2.5}$ at receptors located within approximately 20 km of the Project site. AERMOD was run with default model options in the CONTROL pathway, unless otherwise noted. AERMOD was applied with the rural source option as discussed below.

6.3 Dispersion Environment

ADEM's Modeling Guidelines recommends the use of the Auer scheme in which the land use within a three-kilometer (3-km) area is evaluated to determine the dispersion environment surrounding the Project site.

As shown in Figure 6-1, the satellite imagery of the 3-km area surrounding Plant Barry indicates the area is predominantly rural, with the land use consisting of a mix of mostly swampland, forested areas, wetlands, water and industrial areas.

6.4 Terrain

EPA's GAQM require that the differences in terrain elevations between the stack base and model receptor locations be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;
- intermediate terrain – locations where the terrain is between the top of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological condition);
- complex terrain – locations where the terrain is above the plume centerline.

As shown in Figure 6-2, the area near Plant Barry is characterized as consisting of simple terrain relative to the modeled stacks.

6.5 Good Engineering Practice Stack Height Analysis

EPA's GAQM require the evaluation of the potential for physical structures to affect the dispersion of emissions from stack emission points. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" ("GEP") stack height analysis. Stacks with heights below physical GEP are considered to be subject to building downwash.

A GEP stack height analysis was performed for each of the stacks associated with the Project in accordance with EPA's guidelines (EPA 1985). Per the guidelines, the physical GEP height ("H_{GEP}") is determined from the dimensions of all buildings that are within the region of influence using the following equation:

$$H_{GEP} = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_{GEP}, and
L = lesser dimension (height or projected width) of the structure.

For a squat structure, i.e., height less than projected width, the formula reduces to:

$$H_{GEP} = 2.5H$$

In the absence of influencing structures, a "default" GEP stack height is credited up to 65 meters (213 feet).

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. In all instances, the GEP stack height is based on the plane projections of any nearby building which result in the greatest justifiable height. For purposes of the GEP analysis, nearby refers to the "sphere of influence," defined as five times the height or width of the building, whichever is less, downwind from the trailing edge of the structure. In the case where a stack is not influenced by nearby structures, the maximum GEP stack height is defined as 65 meters.

The current Project design has all modeled stacks less than 65 meters. As such, all Project stacks were modeled using their actual stack height. In addition, the EPA's Building Profile Input Program (BPIP-Version 04274) version that is appropriate for use with PRIME algorithms in AERMOD was used to incorporate downwash effects in the model for all modeled stacks. The building dimensions of each structure were input in BPIPPRM program to determine direction specific building data. All relevant new and existing building structures were included in the BPIP modeling for both new and existing stacks. PRIME addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake.

For the existing facility sources, Barry Units 1 and 2 share a common stack. The actual height of the combined Barry Units 1 and 2 stack is 600 feet (ft). The GEP controlling structure for this stack is the boiler house for Unit 5 (height: 202 ft with a projected width greater than the height). Therefore, the GEP stack height is 505 feet (2.5 x 202 ft). The GEP stack height of 505 ft was established in a letter dated December 11, 1985, from Mr. W. L. Bowers of Alabama Power to Mr. Richard E. Grusnick of ADEM. A copy of this letter is attached in Appendix H. Cumulative modeling performed for this application uses the GEP stack height of 505 ft for the Barry Units 1 and 2 common stack.

Barry Unit 4 has a single dedicated stack at a physical stack height of 600 ft. Unit 5 also has a dedicated stack with a bypass stack both of which are at physical heights of 600 ft. The GEP controlling structure for the Unit 4 and Unit 5 stacks is the boiler house for Unit 5 (height: 202 ft with a projected width greater than the height). Therefore, the GEP stack height is 505 ft (2.5 x 202 ft) for each stack. However, these stacks are grandfathered from the GEP Stack Height Regulations (i.e., credit for full stack height can be taken in modeling analysis, even though this stack height is above the calculated GEP height of 505 ft). This is documented in a letter dated December 11, 1985, from Mr. W. L. Bowers of Alabama Power to Mr. Richard E. Grusnick of ADEM. A copy of this letter is attached in Appendix H. Cumulative modeling performed for this application uses the actual stack height of 600 ft for the Barry 4 or 5 stacks.

6.6 Meteorological Data

No on-site meteorological data are available, so the application of a refined dispersion model requires five years of hourly meteorological data that are representative of the Project site. In addition to being representative, the data must meet quality and completeness requirements per EPA's GAQM. Per Appendix B of ADEM's Modeling Guidelines, surface data from Mobile Regional Airport in Alabama should be used in the modeling analysis. Mobile Regional Airport is located approximately 25 miles southwest of Plant Barry.

Five contiguous years of data from Mobile Regional Airport (2014-2018) with concurrent upper air data from Slidell Airport in Louisiana, as provided by ADEM, was used in the analysis. The pre-processed meteorological data (profile and surface files) for use with AERMOD was provided by ADEM and processed with AERMET (Version 19191) (EPA 2019b). The locations of Mobile Regional and Slidell airports relative to the project location are shown in Figure 6-3. Figure 6-4 shows a five-year wind rose for Mobile Regional Airport (2014-2018).

In accordance with ADEM's Modeling Guidelines, a comparison of the average land use characteristics over the five-year meteorological period (2014-2018) for Mobile Regional Airport and the Projects site was performed and shows differences in both the Bowen ratio and the surface roughness. Due to these differences in the land use characteristics, dispersion modeling up through the SIL analysis was conducted using two meteorological data sets; the first using the land use characteristics surrounding Mobile Regional Airport (AP) as provided by ADEM and the second using the land use characteristics surrounding the Plant Barry site (SITE) processed by AECOM. Appendix I provides a description and detailed results of the land use analysis.

AERMET Stage 3 input files and merge files (merged surface and upper air data created during Stage 2 of AERMET) for the five meteorological years (2014-2018) processed with AERMET Version 19191 and provided by ADEM, was used to process the second meteorological data set using the SITE land use characteristics using AERMET Version 19191.

6.7 Receptor Processing with AERMAP

A comprehensive Cartesian receptor grid extending a minimum of 20 km from the Project's ambient boundary was used in the AERMOD modeling to assess ground-level ambient air concentrations. The 20-km receptor grid was more than sufficient to resolve the maximum impacts and any potential significant impact area(s) (SIA).

The nested Cartesian receptor grid consists of the following receptor spacing:

- From the center of the plant (UTM northing = 3,429,800 meters and UTM easting = 404,100 meters) out to a distance of 4,800 meters (m) at 100-m increments
- Beyond 4,800 m to 6,800 m at 250-m increments
- Beyond 6,800 m to 12,000 m at 500-m increments
- Beyond 12,000 m to 22,500 m at 1000-m increments

No additional fine grid receptors were needed as the location of maximum modeled concentrations occurred within areas containing 100-m spaced receptors. Figure 6-5 shows the modeling boundary consisting of fence, swampland, river and barge canal banks controlled and patrolled areas. Below is a description of the various segments of the proposed ambient air boundary:

- Segment #1 consists in part of the Mobile River bank, thick vegetation, "Warning, Private Property, No Trespassing, Violators Will be Prosecuted" signs, some fencing, and road access is gated. The gate is locked and requires badge access to open. Additionally, this area is patrolled by plant security personnel, is under direct surveillance by the plant personnel working in the barge canal and is under video surveillance. Therefore, this area of Plant Barry delineated by segment #1 is patrolled and controlled and is not ambient air.
- Segment #2 consists of the interface between the Mobile River and the man-made barge canal. The canal was constructed by Alabama Power for the dedicated use by Plant Barry. Barge unloading and the constant presence of coal barges along with the pilings and coffer dams located within this narrow canal act as a physical barrier to other vessels. There are "Private Property, No Trespassing" signs on the river bank at the mouth of the canal. The Plant Barry coal generating units are situated at the mouth of the canal and the fuel pile runs along the length of the canal. This area is patrolled and under surveillance – including closed circuit television (CCTV) surveillance of the mouth of the canal and at the barge unloading area –and as such, the area inside the barge canal is not ambient air.

- Segment #3 consists of the Mobile River bank along the existing ash pond and levee. The steep banks of the river and levee are barriers that restrict public access. In addition, a road runs parallel to the river along this segment to the southeast discharge canal and then circles back to the main generating plant building. This road is patrolled by plant security personnel. Therefore, public access to plant areas inside this segment is controlled and patrolled and, as such, this area is not ambient air.
- Segment #4 delineates swamp land that is impassable due to the terrain and vegetation. The area has no roads and is not navigable or accessible to vehicles. Further, there is "No Trespassing" signage at the river, and steep natural terrain barriers in the area of the transmission line rights-of-way. Therefore, the natural barriers and the absence of roads are sufficient to restrict public access and consider this segment controlled, and as such, the area inside segment #4 is not ambient air.
- Segment #5 outlines an area of thick vegetation along the boundary that inhibits access. Further, there is a steep bank along the north-south section of this segment. The lone access road that can access plant area in this segment will become the main plant entrance to the new combined cycle units and will run north, adjacent to the ambient air boundary and as such all visitors must pass through plant security. Further, there is CCTV surveillance in this area as well as "Warning, Private Property, No Trespassing, Violators Will be Prosecuted" signs posted at the gated access point. Therefore, this segment should be considered patrolled and controlled, and as such, the area inside segment #5 is not ambient air.
- Segment #6 consists of a small area around the path providing access to the Ellicott Stone historical marker. The Ellicott Stone is a survey boundary marker that was set by Andrew Ellicott when he surveyed the 31st parallel north latitude in 1799. The sandstone boundary marker is protected by a fence and roof covered pavilion. There is public access to the area from Highway 43 along a marked foot pathway leading to the Ellicott Stone. This segment will include fencing and "Warning, Private Property, No Trespassing, Violators will be Prosecuted" signs to restrict public access beyond the pathway. Because this segment will be controlled with fencing, signage, and surveillance, it establishes the ambient air boundary.
- Segment #7 contains the main plant entrance and contractor gates and as such, all visitors must pass through plant security. Further, areas of this segment have some fencing and are under surveillance by workers located at Barry Units 6 and 7. Further, there is CCTV surveillance in this area. These factors are sufficient to consider this area of Plant Barry to be patrolled and controlled. As such, the plant area bounded by segment #7 is not ambient air.

AERMAP (version 18081) (EPA 2018b), AERMOD terrain preprocessor program, was used to calculate terrain elevations and critical hill heights for the modeled receptors (NAD83 datum and zone 16) using United States Geological Service (USGS) National Elevation Data (NED). The dataset that was downloaded using the Lakes Environmental AERMOD View software consists of 1/3 arc second (~10-m resolution) NED. As per the AERMAP User's Guide (EPA, 2018b), the AERMAP domain extent was sufficient to ensure that all significant nodes were included such that all terrain features that exceed a 10 percent elevation slope from any given receptor are considered. The NED files are referenced to Datum NAD83 (note all source locations and receptors were referenced to NAD83 UTM Zone 16). The NED files are included in the modeling archive provided in Appendix G of this application.

The extent of the proposed initial receptor grid is shown in Figure 6-6 (near-field) and Figure 6-7 (far-field).

6.8 Secondary $PM_{2.5}$ and Ozone - Approaches and Analyses

In April 2019, EPA released the final *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program (EPA-454/R-19-003)* [45] (2019 EPA MERP Guidance). This guidance replaces the draft MERP Guidance that was released in April 2016. Section 4 of the 2019 EPA MERP Guidance provides several examples of MERP Tier 1 demonstrations for sources subject to PSD review. The examples focus on both secondary $PM_{2.5}$ and ozone precursor emissions and at what emission levels those precursors would result in a potential project insignificant impact, which would eliminate the need for project-specific modeling. Section 4.1.3 of the 2019 EPA MERP Guidance also illustrates how the EPA-model data used to develop the MERPs could be used as a Tier 1 demonstration tool in a cumulative impact analysis for both $PM_{2.5}$ and ozone. ADEM's Modeling Guidelines also requires that impacts associated with secondary $PM_{2.5}$ and ozone be addressed in a PSD application, and ADEM requires the use of the MERPs in an analysis.

6.8.1 Approaches

For this Project, most of the precursor emissions (as shown in Table 6-7) for both $PM_{2.5}$ and ozone are below the lowest MERPs found in Table 4-1 of the 2019 EPA MERP Guidance for sources located in the Southeastern United States. The only exception is for NO_X as a precursor to 8-hour ozone. However, even the use of a site-specific MERP value developed using EPA Guidance for one of the hypothetical sources located in Alabama, the Project would still show Project emissions greater than that site-specific MERP. In addition, the Project has modeled impacts of primary $PM_{2.5}$ that exceed the $PM_{2.5}$ SIL. As such, the methodology described in Section 4.1.3 of the 2019 EPA MERP Guidance was utilized to assess Project and cumulative impacts for $PM_{2.5}$ and ozone.

Table 6-7: Comparison of Project Precursor Emissions with Lowest MERPs

Pollutant	Precursor Pollutant	Project Emissions (1) (TPY)	Lowest MERP (TPY)
8-hour Ozone	NO_X	350.2	170
	VOC	383.4	1,936
24-hour $PM_{2.5}$	NO_X	350.2	1,943
	SO_2	70.9	367
Annual $PM_{2.5}$	NO_X	350.2	5,679
	SO_2	70.9	859

(1) Project precursor emissions are preliminary and subject to change.

Specifically, Scenario B in Section 4.1.3 of the 2019 EPA MERP Guidance was followed. To estimate the Project impact of ozone and secondary $PM_{2.5}$, two hypothetical sources that were modeled by EPA in Alabama were considered. These hypothetical sources are located in Autauga and Tallapoosa Counties. In addition, for this assessment the EPA-modeled concentrations associated with the elevated source was used as the proposed Project stacks are elevated and have buoyant releases.

[45] Memo from Richard A. Wayland, Dir., Air Quality Assessment Div., on Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program to Reg'l Air Div. Dirs. (Apr. 30, 2019), https://www3.epa.gov/ttn/scram/guidance/guide/EPA-454_R-19-003.pdf.

Either of the EPA hypothetical sources in Alabama would conservatively represent the airshed of the Project source in Mobile County, AL because both sources are located in similar climate regimes as the Project, and all three source locations exhibit warm and humid climates during the ozone season. For Autauga, Tallapoosa, and Mobile Counties, climate summaries from the Southeast Regional Climate Center (https://sercc.com/) indicate very similar 30-year climate normals when comparing the location of the two EPA hypothetical sources and Plant Barry. Specifically, the 30-year (1971-2000) average maximum, minimum and total precipitation is provided in Table 6-8. Specifically, Table 6-8, shows very similar annual average high temperatures in the mid 70s°F with low temperatures in the 50s°F. In addition, each county's mid-summer (peak ozone season) higher temperatures exceed 90°F. Precipitation averages are also close with each county getting approximately 50-60 inches of rain per year.

Table 6-8: 30-Year Climate Normals for Tallapoosa, Autauga, and Mobile Counties, Alabama

Station/Source	Parameter	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Alexander City, Alabama (010160) / Tallapoosa Co.	Average Max. Temperature (°F)	54.9	60.1	68	75.3	81.9	87.9	90.7	89.8	85.3	76.5	64.7	58.1	74.6
	Average Min. Temperature (°F)	31.9	34.6	41.3	48.2	56.9	64.8	68.6	67.7	61.6	49.7	39.6	34.6	50.1
	Average Total Precipitation (in.)	5.89	5.46	6.19	4.79	4.25	4.52	5.24	4.34	3.9	3.08	4.41	5.02	57.09
Montgomery WSO ARPT, Alabama (015550) / Autauga Co	Average Max. Temperature (°F)	57.4	62.4	69.7	76.5	83.5	89.4	91.8	91.4	87.1	78.1	66.4	60.3	76.4
	Average Min. Temperature (°F)	36.3	39.5	45.8	52.2	60.7	67.9	71.4	70.8	65.3	53.4	43.1	38.7	53.9
	Average Total Precipitation (in.)	5.37	5.43	6.13	4.47	4.05	4.3	5.15	3.96	3.79	2.99	4.3	4.98	54.92
Mobile WSO ARPT, Alabama (015478) / Plant Barry	Average Max. Temperature (°F)	60.8	64.9	71.3	77.5	84.2	89.2	91	90.6	86.8	79	68	63.1	77.4
	Average Min. Temperature (°F)	40.8	43.8	49.9	56.2	64	70.4	72.9	72.8	68.2	57.4	47.4	43	57.4
	Average Total Precipitation (in.)	5.77	5.25	6.52	5.63	5.77	5.22	6.74	6.32	5.4	3.65	5.05	5.03	66.35

In addition, no significant terrain features are present that would alter the climate regimes between the Project source and the EPA hypothetical sources located in Autauga and Tallapoosa Counties. However, Autauga County is slightly more representative of Mobile County as both have relatively flat terrain compared to Tallapoosa County which has some gently rolling hills.

Both areas surrounding the EPA hypothetical sources also exhibit similar land use to the Project area (located in Mobile County) as primarily being forested, agricultural and residential areas. The EPA hypothetical sources located in Autauga and Tallapoosa Counties are located in rural areas of the county similar to the Project's location within Mobile County. However, the Autauga County source would be more representative as it is located in similar proximity to the City of Montgomery, AL compared to the Project's proximity to the City of Mobile, AL.

Based on the factors discussed above associated with land use, climate, and terrain, the data associated with EPA's hypothetical source in Autauga County was used for assessing the impact on ozone and secondary $PM_{2.5}$ for this Project.

6.8.2 Analyses

Secondary $PM_{2.5}$

As stated, and discussed in Section 7.0, direct modeled $PM_{2.5}$ concentrations exceed the SIL for this Project. As such, the analysis for secondary $PM_{2.5}$ was based on EPA guidance contained in Section 4.1.3 of the 2019 EPA MERP Guidance. Project-specific secondary $PM_{2.5}$ concentrations were estimated using Equation 2 (shown below) from Section 4.1.3 of the 2019 EPA MERP Guidance which is based on the relationship of precursor NO_X and SO_2 emissions with secondary $PM_{2.5}$ concentrations from EPA-modeled hypothetical sources.

$$\text{Eq. 2} \quad \text{Project Impact} = \text{Project emission rate} \times \frac{\text{Modeled air quality impact from hypothetical source}}{\text{Modeled emission rate from hypothetical source}}$$

These secondary $PM_{2.5}$ concentrations were added to Project direct modeled $PM_{2.5}$ (using AERMOD) to estimate total Project concentrations for both the SIL and NAAQS/PSD increment analyses, as applicable. The Project secondary $PM_{2.5}$ concentrations are calculated in Table 6-9. These concentrations are added to modeled AERMOD concentrations to demonstrate compliance with the NAAQS and PSD increments as applicable for $PM_{2.5}$.

Table 6-9: Project Estimated Secondary $PM_{2.5}$ Concentrations

Averaging Period	NO_X				SO_2				Project Estimated Secondary $PM_{2.5}$ Concentration (µg/m³)
	EPA Precursor Emissions (TPY)	EPA Modeled Concentration (µg/m³)	Project Precursor Emissions (TPY)	Project Estimated Concentration (µg/m³)	EPA Precursor Emissions (TPY)	EPA Modeled Concentration (µg/m³)	Project Precursor Emissions (TPY)	Project Estimated Concentration (µg/m³)	
24-hour	500	0.076	350.2	0.05	500	0.270	70.9	0.04	0.092
Annual	500	0.002	350.2	0.001	500	0.007	70.9	0.0010	0.002

Ozone

For the ozone precursors NO_X and VOC, a similar approach (to $PM_{2.5}$) was used as outlined in the 2019 EPA MERP Guidance. The same hypothetical source from Autauga County modeled by EPA was considered.

Project-specific ozone concentrations were again estimated using Equation 2 from Section 4.1.3 of the 2019 EPA MERP Guidance which is based on the relationship of precursor NO_X and VOC emissions with ozone concentrations from EPA-modeled hypothetical sources. The Project ozone concentrations are calculated in Table 6-10. This concentration was added to monitored design concentration according to Equation 3 (see below) in Section 4.1.3 of the 2019 EPA MERP Guidance to estimate the total ozone concentration that was then compared to the NAAQS.

Table 6-10: Project Estimated Ozone Concentrations

Averaging Period	NO_X				VOC				Project Estimated Ozone Concentration (ppb)
	EPA Precursor Emissions (TPY)	EPA Modeled Concentration (ppb)	Project Precursor Emissions (TPY)	Project Estimated Concentration (ppb)	EPA Precursor Emissions (TPY)	EPA Modeled Concentration (ppb)	Project Precursor Emissions (TPY)	Project Estimated Concentration (ppb)	
8-hour	500	2.414	350.2	1.69	500	0.064	383.4	0.05	1.74

Eq. 3 Projected Design Value with Project = Project Impact (Eq. 2) + Monitored Design Value

The closest and most representative ambient air quality monitor to the Project is the state-operated Chickasaw monitor. The applicable ozone air quality data from this monitor is summarized in Table 6-11. The Project is located in a rural area. Most of the surrounding land use is forested or used for agriculture with some small residential areas and other industrial sources. The Chickasaw ozone monitor is located approximately 25 km southwest of the Project in an area that is more populated based on its proximity to the City of Mobile, AL. The three year (2016-2018) 8-hour ozone NAAQS design value for Chickasaw is 64 ppb based on design value summaries from EPA[46]. Using equation 3 (above) and adding the Project estimated ozone concentration (from Table 6-10) of 1.74 ppb to the 64 ppb design value results in a total concentration of 65.74 ppb, which is below the NAAQS of 70 ppb. Thus, no additional analyses are warranted for the Project to show compliance with the ozone NAAQS.

Table 6-11: 8-Hour Ozone Design Values for 2016-2018

State-Operated Ozone Monitor	Year	High 4th High Concentration (ppb)	Design Concentration (3-year average) (ppb)
Chickasaw 10970003 Mobile County, AL	2016	62	64
	2017	65	
	2018	65	

Ozone concentration data taken from the EPA Air Trends website (https://www.epa.gov/air-trends/air-quality-design-values)

6.9 Background Air Quality and Pre-Construction Monitoring

6.9.1 Available Representative Ambient Air Quality Data

Ambient air quality data are used to represent the contribution to total ambient air pollutant concentrations from non-modeled sources. In accordance with 40 CFR 52.21(m) and ADEM Admin Code r. 335-3-14.04 (12), an application for a PSD permit must contain an analysis of ambient air quality in the vicinity of the proposed Project for each pollutant subject to PSD review. The objective of reviewing this data is to develop representative background concentrations which, when added to modeled impacts, are used in the NAAQS compliance analysis.

The representative background concentrations contained in Table 6-12 were provided by ADEM and were used in the air quality analysis for this Project. Table 6-12 summarizes background concentrations that were used as part of the NAAQS modeling demonstration. The design concentration values listed in Table 6-12 were added to the modeled design concentration to estimate the total impact for applicable pollutants. Pollutants not presented in Table 6-12 have modeled concentrations less than the SILs. Ozone background concentrations are presented in Table 6-11. Air Quality System reports for $PM_{2.5}$, NO_2, and ozone are provided in Appendix J.

[46] EPA, *Ozone Design Values 2016-2018 Final* (June 28, 2019), https://www.epa.gov/sites/production/files/2019-07/ozone_designvalues_20162018_final_06_28_19.xlsx.

Table 6-12: Monitored Background Concentrations

Pollutant	Averaging Period	Concentration	Units	Location	State
$PM_{2.5}$	24-hour	17	$\mu g/m^3$	Chickasaw	AL
	Annual	8.1	$\mu g/m^3$		
NO_2	1-hour	16 31	ppb $\mu g/m^3$	Yorkville	GA

6.9.2 Pre-construction Monitoring

The PSD regulations require that a PSD permit application contain an analysis of existing air quality for all regulated pollutants that the source has the potential to emit in significant amounts. The definition of existing air quality can be satisfied by air measurements from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. To fulfill the pre-construction monitoring requirement for PSD without conducting on-site monitoring a source may either:

1. Use data collected from existing monitoring sites that are conservatively representative of the air quality in the vicinity of the proposed Project site; or

2. Demonstrate through modeling the ambient impacts from the proposed Project is less than the *de minimis* levels per ADEM's Modeling Guidelines (see Table 6-13 below).

As such, if the source-only modeled concentrations are greater than the *de minimis* monitoring concentrations found in Table 6-13, the proposed Project proposes to use the background air quality data summarized in Section 6.9.1 to quantify existing air quality for the proposed Project site.

Table 6-13: *De Minimis* Monitoring Concentrations

Pollutant	Averaging Time		
	Annual *µg/m³*	**24-hour** *µg/m³*	**8-hour** *µg/m³*
NO_2	14	-	-
CO	-	-	575
$PM_{2.5}$	-	*	-
PM_{10}	-	10	-
SO_2	-	13	-
O_3	-	-	VOC emission increase > 100 TPY

*For $PM_{2.5}$ ADEM was contacted and ambient background concentration data was provided.

Figure 6-1: Land Use within 3 km of Plant Barry – Aerial Photo

Figure 6-2: Topography in the Vicinity of Plant Barry

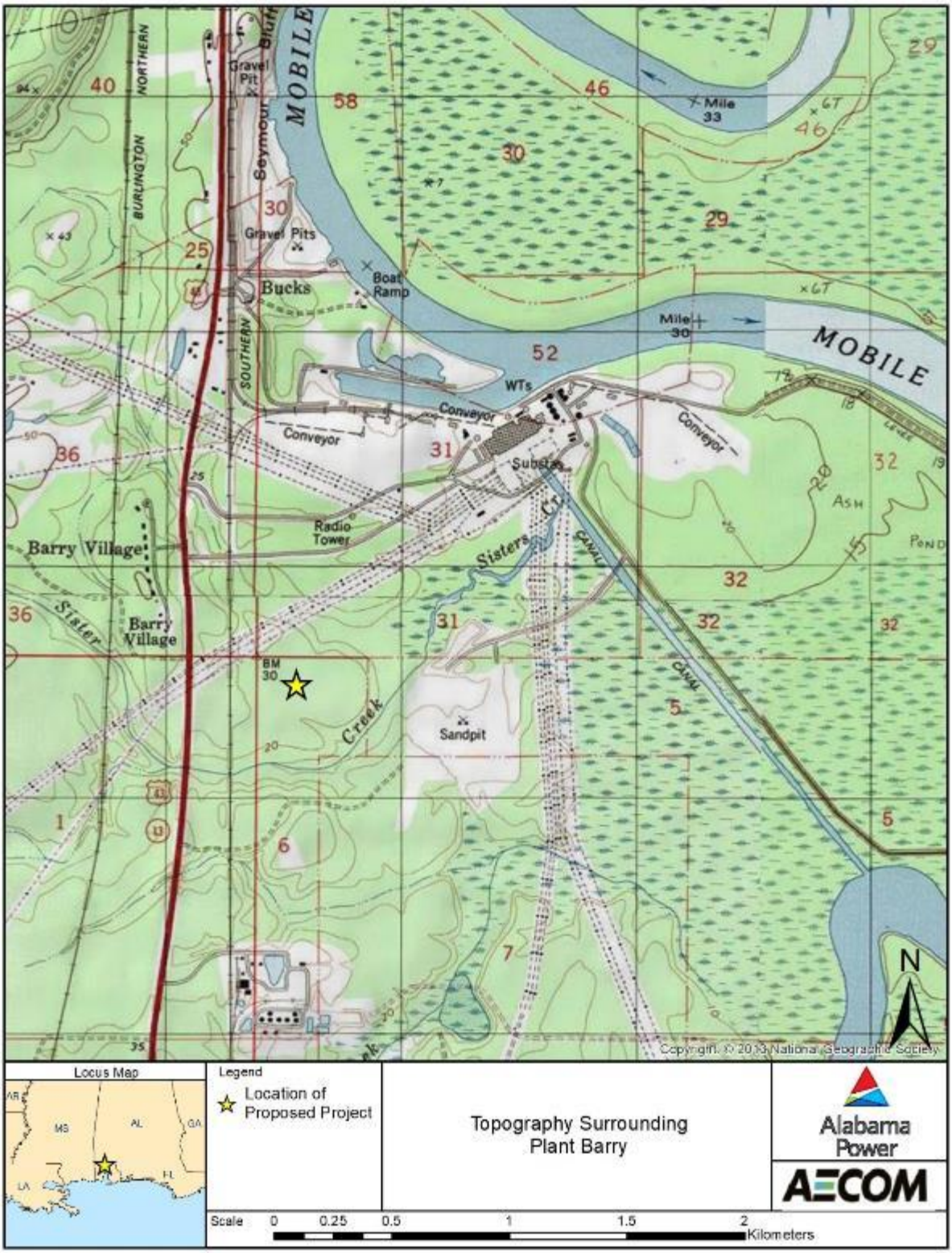


Figure 6-3: Location of Meteorological Sites Relative to Plant Barry

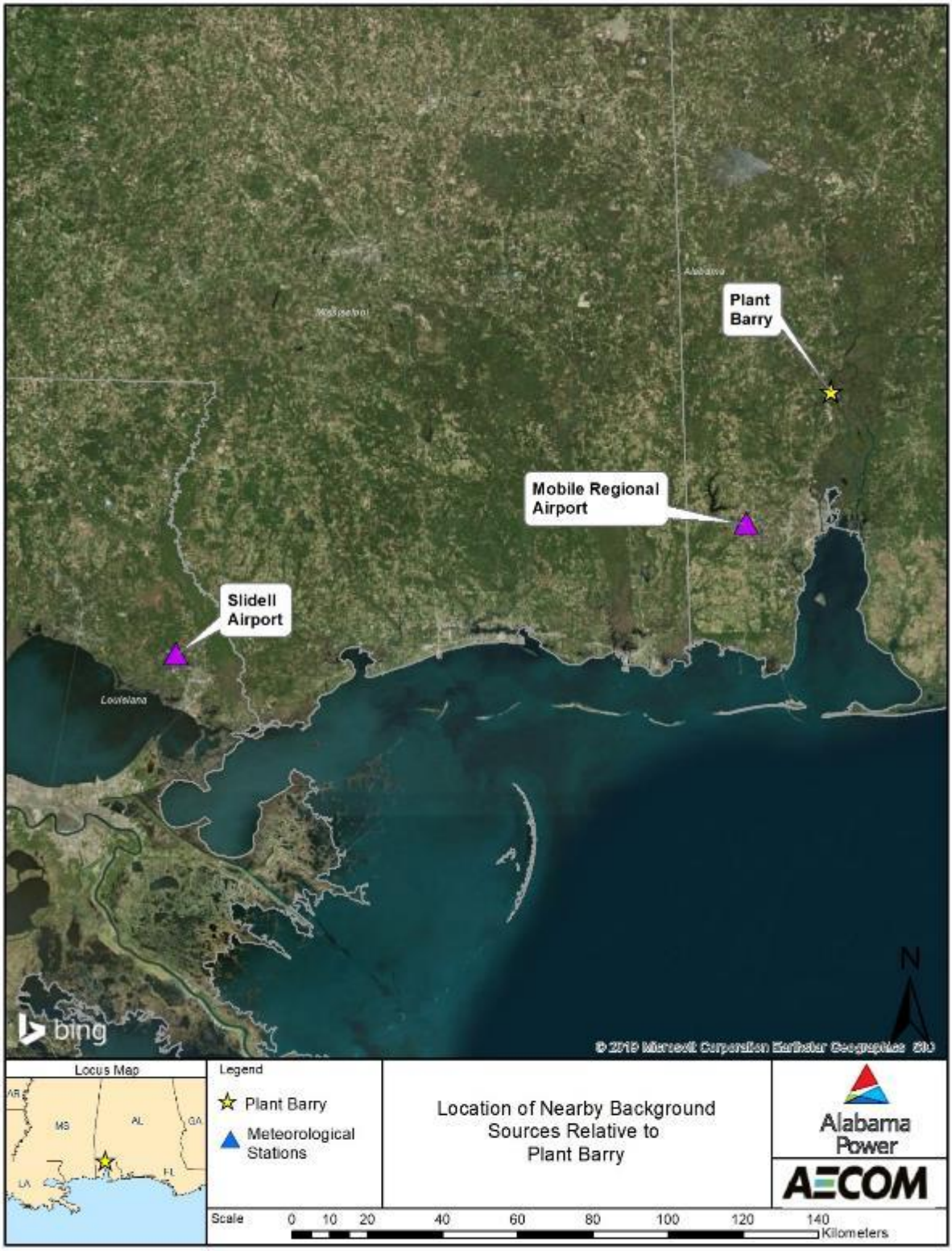


Figure 6-4: Wind Rose for Mobile Regional Airport (2014-2018)

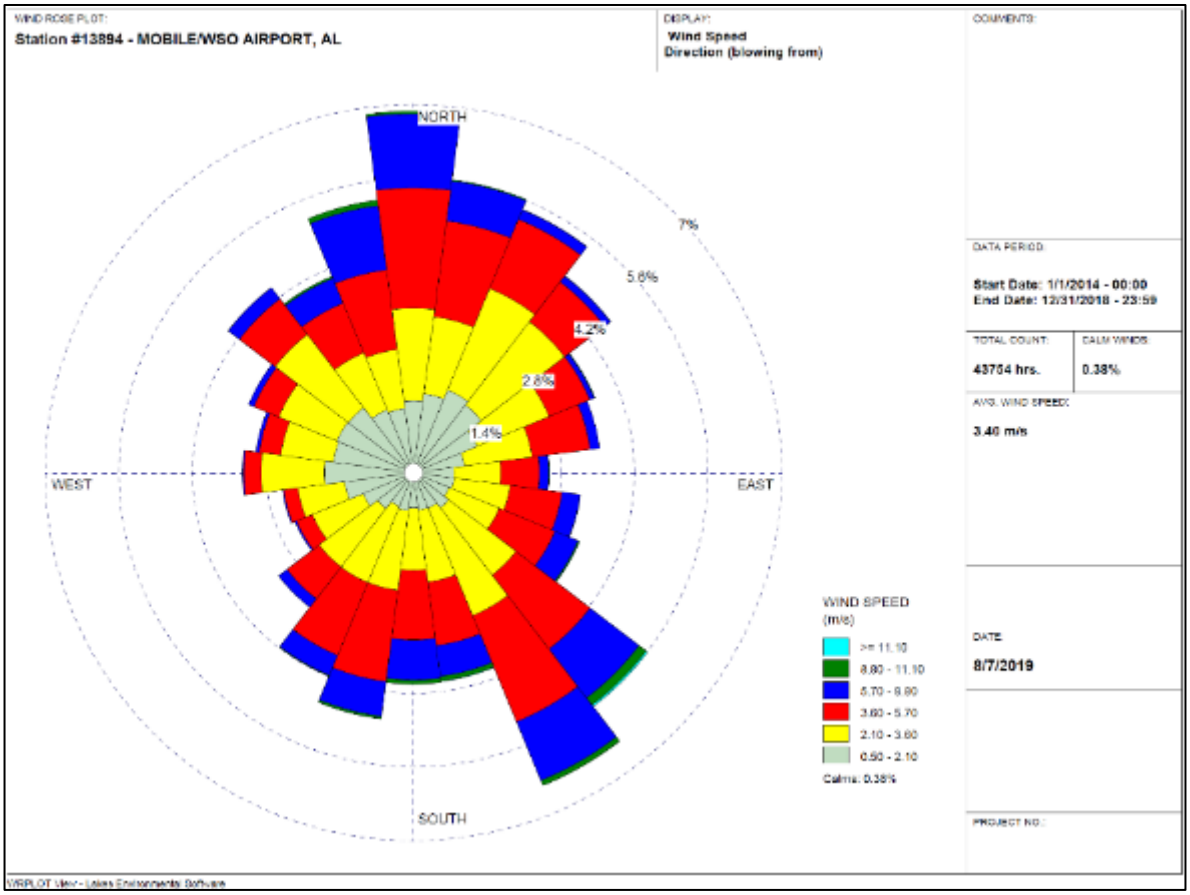


Figure 6-5: Proposed Ambient Air Boundary

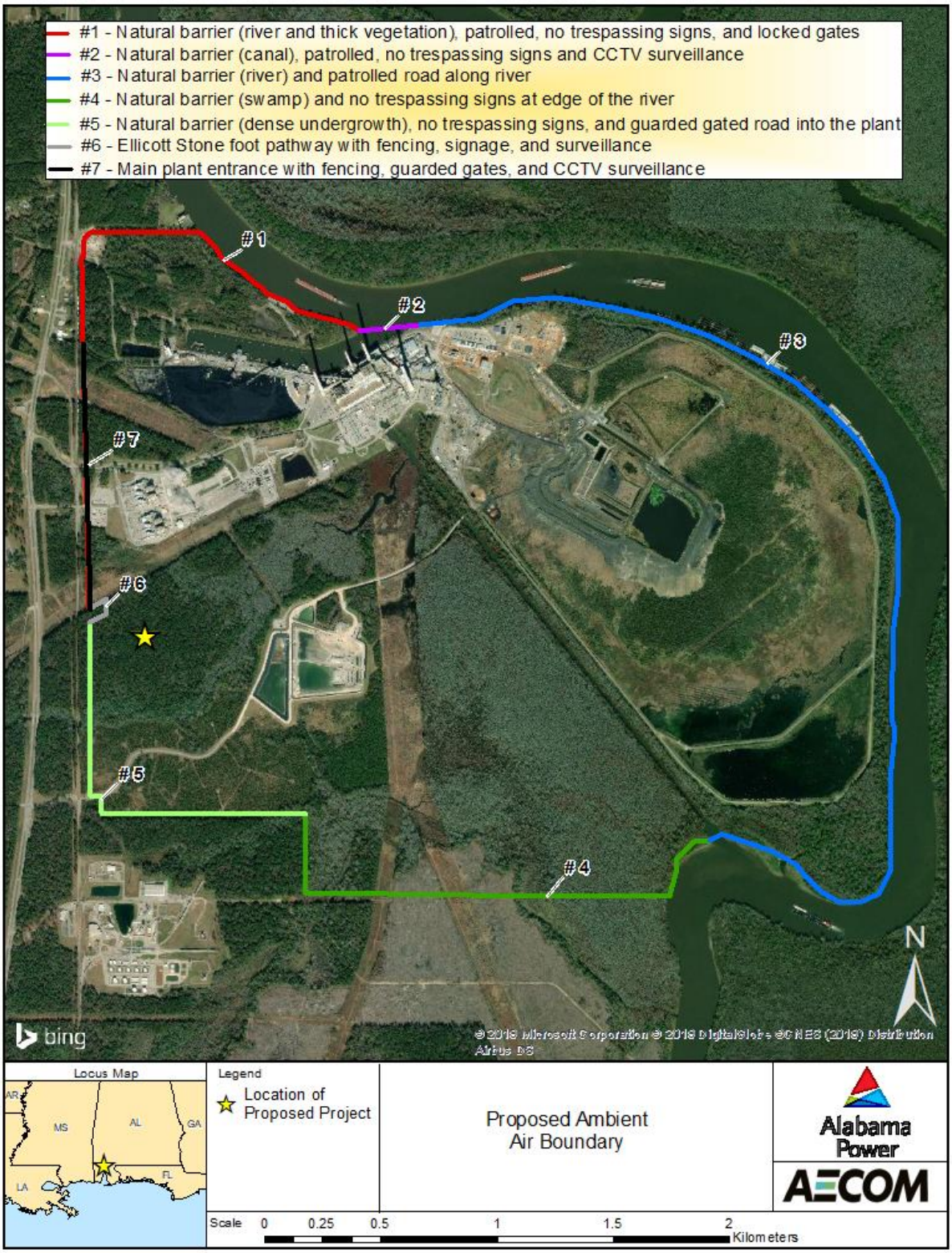


Figure 6-6: Near-Field View of Receptor Grid

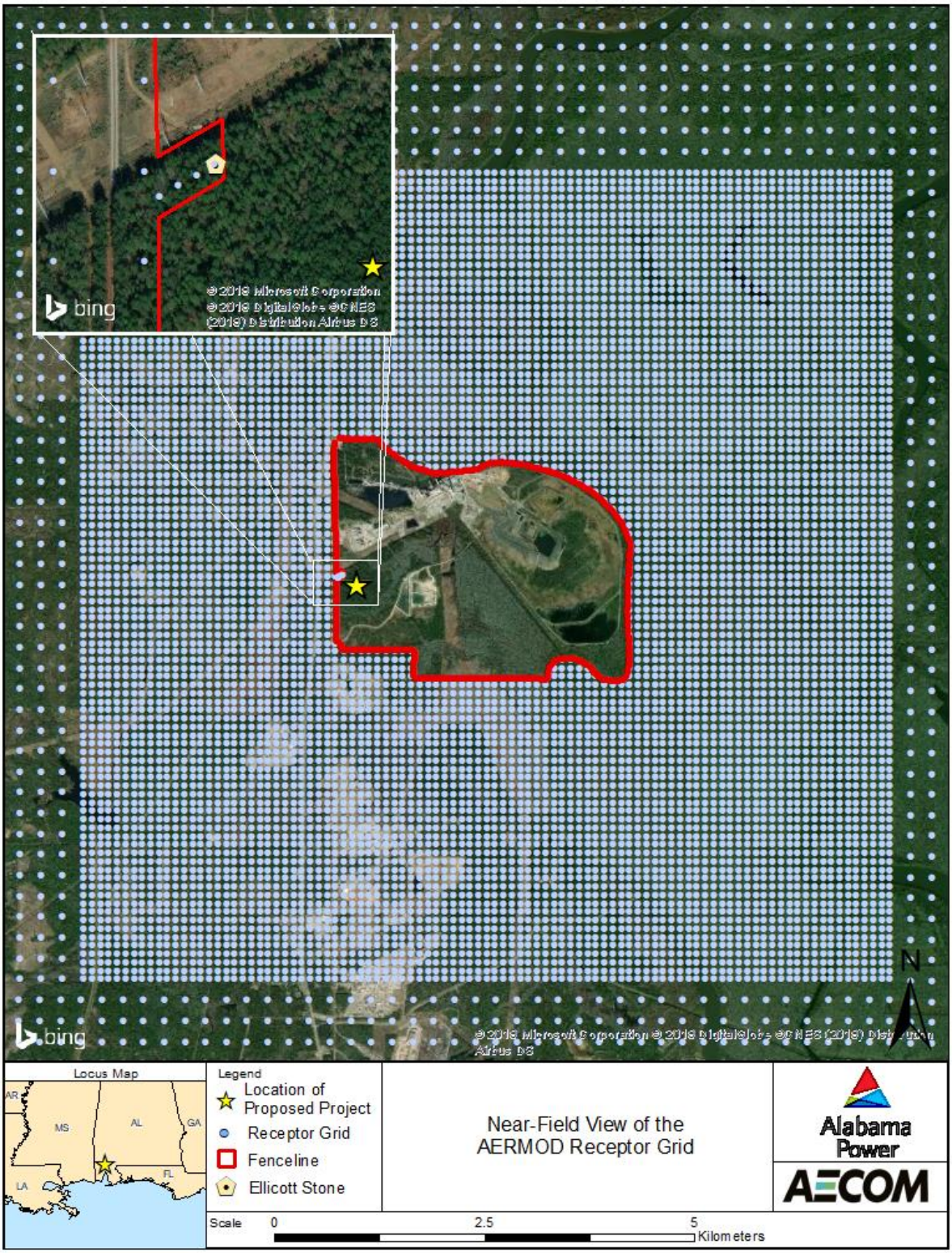
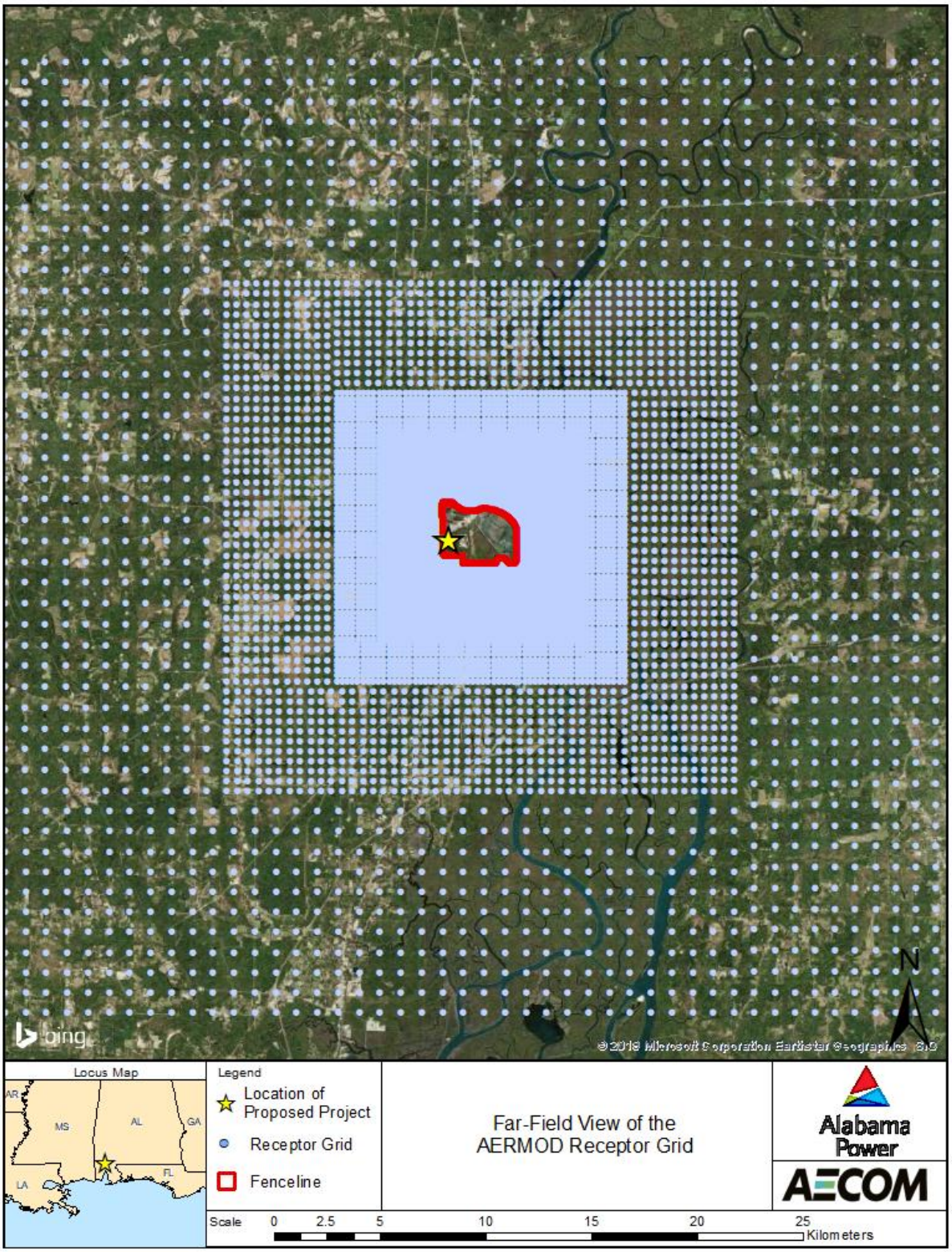


Figure 6-7: Far-Field View of Receptor Grid



7.0 Class II Area Significant Impact Level Analysis Results

7.1 Load Analysis

Prior to performing the Class II Area SIL analysis, a load analysis for the two CC units was performed to determine the worst-case condition (pre- vs. post-upgrade and operating loads) in terms of ground-level concentrations for the Project. This analysis was performed using data in Tables 6-4 and 6-5 along with normalized emission rates assuming 100% conversion of NO_X to NO_2 (Tier 1 Option). Model results were predicted for each applicable averaging period, including 1-hour, 3-hour, 8-hour, 24-hour, and annual.

The normalized concentrations associated with the load analysis run were used to calculate pollutant and averaging period-specific concentrations in order to determine which resulted in the highest modeled concentration. This modeling analysis was performed with AERMOD and the associated databases as described in Sections 6.2 through 6.7 including both the meteorological databases developed using airport (AP) and Plant Barry (SITE) land use characteristics.

The results of the turbine load analysis are shown in Tables 7-1 and 7-2 for the Airport (AP) and Plant Barry (SITE) land use meteorological databases, respectively. Table 7-1 shows that for the AP land use, the pre-upgrade configuration results in higher modeled concentrations for all pollutants and averaging periods. Table 7-2 shows that for the SITE land use, the pre-upgrade configuration results in higher modeled concentrations for NO_2 (1-hour and annual), CO (1-hour), and SO_2 (1-hour, 24-hour, and annual), while the post-upgrade configuration results in higher modeled concentrations for CO (8-hour), PM_{10}/$PM_{2.5}$ (24-hour and annual) and SO_2 (3-hour).

The actual load condition associated with the highest modeled concentration is summarized in Table 7-3 for each meteorological database and pollutant/averaging period. These load conditions were used to complete the SIL modeling analyses presented in Section 7.2.

Table 7-1: Load Analysis Modeling Results – Airport (AP) Land Use Characteristics

Pre-Upgrade Configuration													
Load Scenario	**Model ID**	**Maximum Modeled Concentration per Averaging Period (μg/m³)**											
		NO_2	**NO_2**	**CO**	**CO**	**$PM_{2.5}$**	**$PM_{2.5}$**	**PM_{10}**	**PM_{10}**	**SO_2**	**SO_2**	**SO_2**	**SO_2**
		1hr	**Ann**	**1hr**	**8hr**	**24hr**	**Ann**	**24hr**	**Ann**	**1hr**	**3hr**	**24hr**	**Ann**
Base Load + DB + IC	PRE_DB	**12.25**	**0.17**	**7.45**	**4.20**	**1.40**	**0.09**	**1.40**	**0.09**	**2.58**	**1.73**	**0.56**	**0.04**
Base Load + IC (no DB)	PRE_IC	8.58	0.11	5.23	2.63	0.78	0.05	0.78	0.05	1.82	1.20	0.35	0.02
Base Load (no IC, no DB)	PRE_BL	9.61	0.13	5.87	3.46	1.02	0.06	1.02	0.06	2.04	1.42	0.46	0.03
75% Load	PRE_75	9.05	0.14	5.51	3.71	1.14	0.07	1.14	0.07	1.93	1.45	0.50	0.03
50% Load	PRE_50	7.45	0.13	4.55	3.43	1.18	0.07	1.18	0.07	1.59	1.31	0.50	0.03
Post-Upgrade Configuration													
Load Scenario	**Model ID**	**Maximum Modeled Concentration per Averaging Period (μg/m³)**											
		NO_2	**NO_2**	**CO**	**CO**	**$PM_{2.5}$**	**$PM_{2.5}$**	**PM_{10}**	**PM_{10}**	**SO_2**	**SO_2**	**SO_2**	**SO_2**
		1hr	**Ann**	**1hr**	**8hr**	**24hr**	**Ann**	**24hr**	**Ann**	**1hr**	**3hr**	**24hr**	**Ann**
Base Load + DB + IC	POS_DB	12.12	0.17	7.38	3.69	1.28	0.09	1.28	0.09	2.54	1.65	0.49	0.03
Base Load + IC (no DB)	POS_IC	9.03	0.12	5.51	2.75	0.79	0.05	0.79	0.05	1.90	1.21	0.36	0.02
Base Load (no IC, no DB)	POS_BL	9.70	0.13	5.92	3.08	0.91	0.06	0.91	0.06	2.04	1.38	0.41	0.03
75% Load	POS_75	9.55	0.14	5.81	3.59	1.09	0.07	1.09	0.07	2.01	1.46	0.48	0.03
50% Load	POS_50	7.82	0.13	4.77	3.48	1.13	0.07	1.13	0.07	1.66	1.33	0.48	0.03

Bold values denote maximum concentration between pre- and post-upgrade scenarios.
NO_2 concentrations conservatively assume 100% conversion of NO_X to NO_2.

Table 7-2: Load Analysis Modeling Results – Plant Barry (SITE) Land Use Characteristics

Pre-Upgrade Configuration													
Load Scenario	**Model ID**	**Maximum Modeled Concentration per Averaging Period (μg/m³)**											
		NO_2	**NO_2**	**CO**	**CO**	**$PM_{2.5}$**	**$PM_{2.5}$**	**PM_{10}**	**PM_{10}**	**SO_2**	**SO_2**	**SO_2**	**SO_2**
		1hr	**Ann**	**1hr**	**8hr**	**24hr**	**Ann**	**24hr**	**Ann**	**1hr**	**3hr**	**24hr**	**Ann**
Base Load + DB + IC	PRE_DB	**12.697**	**0.603**	**7.718**	6.673	3.969	0.321	3.969	0.321	**2.679**	2.337	**1.575**	**0.127**
Base Load + IC (no DB)	PRE_IC	9.277	0.402	5.655	4.827	2.523	0.191	2.523	0.191	1.968	1.738	1.128	0.085
Base Load (no IC, no DB)	PRE_BL	10.250	0.470	6.258	5.471	2.836	0.222	2.836	0.222	2.178	1.942	1.276	0.100
75% Load	PRE_75	9.817	0.470	5.981	5.192	2.809	0.227	2.809	0.227	2.089	1.908	1.237	0.100
50% Load	PRE_50	8.310	0.420	5.071	4.407	2.570	0.213	2.570	0.213	1.776	1.620	1.082	0.090
Post-Upgrade Configuration													
Load Scenario	**Model ID**	**Maximum Modeled Concentration per Averaging Period (μg/m³)**											
		NO_2	**NO_2**	**CO**	**CO**	**$PM_{2.5}$**	**$PM_{2.5}$**	**PM_{10}**	**PM_{10}**	**SO_2**	**SO_2**	**SO_2**	**SO_2**
		1hr	**Ann**	**1hr**	**8hr**	**24hr**	**Ann**	**24hr**	**Ann**	**1hr**	**3hr**	**24hr**	**Ann**
Base Load + DB + IC	POS_DB	12.651	0.584	7.701	**6.716**	**4.053**	**0.321**	**4.053**	**0.321**	2.655	**2.341**	1.547	0.123
Base Load + IC (no DB)	POS_IC	9.748	0.419	5.942	5.123	2.588	0.195	2.588	0.195	2.050	1.814	1.171	0.088
Base Load (no IC, no DB)	POS_BL	10.424	0.464	6.359	5.497	2.831	0.218	2.831	0.218	2.197	1.931	1.271	0.098
75% Load	POS_75	10.220	0.486	6.211	5.399	2.850	0.230	2.850	0.230	2.152	1.961	1.268	0.102
50% Load	POS_50	8.562	0.430	5.219	4.550	2.603	0.216	2.603	0.216	1.817	1.668	1.102	0.091

Bold values denote maximum concentration between pre- and post-upgrade scenarios.
NO_2 concentrations conservatively assume 100% conversion of NO_X to NO_2.

Table 7-3: Summary of Load Analysis Results

Pollutant	Averaging Period	Worst-Case Load[1]	
		AP Land Use	SITE Land Use
NO_2	1-hour	Pre-Upgrade Base Load + DB + IC	Pre-Upgrade Base Load + DB + IC
	Annual	Pre-Upgrade Base Load + DB + IC	Pre-Upgrade Base Load + DB + IC
PM_{10}	24-Hour	Pre-Upgrade Base Load + DB + IC	Post-Upgrade Base Load + DB + IC
	Annual	Pre-Upgrade Base Load + DB + IC	Post-Upgrade Base Load + DB + IC
$PM_{2.5}$	24-Hour	Pre-Upgrade Base Load + DB + IC	Post-Upgrade Base Load + DB + IC
	Annual	Pre-Upgrade Base Load + DB + IC	Post-Upgrade Base Load + DB + IC
CO	1-Hour	Pre-Upgrade Base Load + DB + IC	Pre-Upgrade Base Load + DB + IC
	8-Hour	Pre-Upgrade Base Load + DB + IC	Post-Upgrade Base Load + DB + IC
SO_2	1-Hour	Pre-Upgrade Base Load + DB + IC	Pre-Upgrade Base Load + DB + IC
	3-hour	Pre-Upgrade Base Load + DB + IC	Post-Upgrade Base Load + DB + IC
	24-hour	Pre-Upgrade Base Load + DB + IC	Pre-Upgrade Base Load + DB + IC
	Annual	Pre-Upgrade Base Load + DB + IC	Pre-Upgrade Base Load + DB + IC

(1) Among the pollutants, averaging periods, and meteorological data sets:
Blue shading = **"Pre"** turbine upgrade case had higher modeled concentrations.
Green shading = "Post" turbine upgrade case had higher modeled concentrations.

7.2 Class II Area SIL Analysis

The Class II Area SIL analysis was conducted using AERMOD for the worst-case operating load on a pollutant and averaging period-specific basis (as determined in Section 7.1) for both the AP and SITE meteorological data sets. In addition to the worst-case operating load for the CC units, the SIL analysis also includes the auxiliary boiler.

The SIL modeling analysis was used to make a determination of significance for NO_2, CO, SO_2, PM_{10}, and $PM_{2.5}$. The determination of significance was made using the highest short-term and highest annual modeled concentration over the five years of meteorological data modeled. For 1-hour NO_2, 1-hour SO_2, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$, significance was determined based on the highest 5-year average concentrations. For this Project, the modeled NO_2 concentrations were assessed using the EPA default Tier 2 ARM2 methodology for estimating NO_2 concentrations from total modeled NO_X emissions.

For those pollutants and averaging periods with modeled concentrations less than their SILs, no further modeling was required because, by definition, those pollutants and averaging periods can be reasonably assumed not to cause or contribute to a violation of a NAAQS or exceedances of the PSD increments. For those pollutants and averaging periods with significant modeled concentrations, a Class II Area cumulative impact analysis was performed to demonstrate compliance with the NAAQS and PSD increments.

For $PM_{2.5}$, the secondary $PM_{2.5}$ concentrations estimated as described in Section 6.8 were added to modeled concentrations for comparison with the SILs.

A comparison of the overall maximum modeled concentrations with the SILs is presented in Table 7-4 for the worst-case operating load for both the AP and SITE meteorological data sets. As is depicted in Table 7-4 all modeled concentrations are below their respective SILs with the exception of 1-hour NO_2 and 24-hour and annual $PM_{2.5}$. As such, no further analyses were required for any modeled pollutants and averaging periods except for 1-hour NO_2 and 24-hour and annual $PM_{2.5}$. A Class II Area cumulative impact analysis for 1-hour NO_2 and 24-hour and annual $PM_{2.5}$ was therefore conducted as documented in Section 8.0.

Concentration isopleths showing the location of the maximum impact consistent with the data shown in Table 7-4 are presented in Appendix K for each pollutant and averaging period. As shown in the concentration isopleths figures contained in Appendix K, all maximum concentrations fall within 100-meter spaced receptors.

Table 7-4: Summary of Maximum AERMOD Concentrations to Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration (µg/m^3)		SIL (µg/m^3)	Significant? (Yes or No)
		AP Land Use	SITE Land Use		
NO_2	1-hour	10.8	11.1	7.5	Yes
	Annual	0.62	0.73	1	No
PM_{10}	24-Hour	3.23	4.92	5	No
	Annual	0.41	0.43	1	No
$PM_{2.5}$	24-Hour	3.07	4.27	1.2	Yes
	Annual	0.36	0.38	0.3	Yes
CO	1-Hour	37.0	34.8	2,000	No
	8-Hour	26.2	28.8	500	No
SO_2	1-Hour	1.83	2.51	7.9	No
	3-hour	1.9	2.5	25	No
	24-hour	0.7	1.7	5	No
	Annual	0.1	0.1	1	No

7.3 Pre-Construction Monitoring

Table 7-5 presents a comparison of the Project's highest modeled concentrations (see Table 7-4) with the monitoring exemption concentrations. The modeled concentrations are below the monitoring exemption concentrations for all pollutants. In addition, as stated in Section 6.9, the VOC emissions increase exceeds the 100 TPY *de minimis* trigger requiring the Project to address pre-construction monitoring for ozone. The existing monitoring data was used to satisfy the Project requirement for ozone pre-construction monitoring.

As such, PSD pre-construction monitoring is not required for this Project.

Table 7-5: Comparison of Modeled Concentrations with Monitoring Exemption Concentrations

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	*De Minimis* Monitoring Concentration ($\mu g/m^3$) (2)
NO_2	Annual	0.73	14
SO_2	24-Hour	1.7	13
CO	8-Hour	28.8	575
PM_{10}	24-Hour	4.92	10

(1) Highest impacts from AERMOD Modeling (from Table 7-2).
(2) From Table 6 of ADEM's Modeling Guidelines.

8.0 Class II Area Cumulative Impact Analysis Results

8.1 Compliance with Class II Area Air Quality Standards and PSD Increments

As stated previously for those pollutants and averaging periods determined to have modeled concentrations less than the SILs, no further analysis was performed. The discussion below applies only to those pollutants and averaging periods for which a significant impact is predicted with AERMOD. The cumulative impact analyses were conducted using methods and databases described in Sections 6 and 7 with the exception that the receptors were limited to the area which the project has a significant modeled concentration.

Compliance with the PSD increments and NAAQS is based on the sum of the following:

- Modeled concentrations attributable to the Project;
- Modeled concentrations from “nearby” sources; and
- Representative ambient background concentration (NAAQS only).

Modeled concentrations attributable to the Project and “nearby” sources were estimated using AERMOD. An inventory of sources was obtained from ADEM to assess cumulative impacts. The modeled design short-term and annual concentration from the proposed Project, as well as influencing nearby emission sources, were compared with the NAAQS and PSD increments. Please note, primary plus secondary $PM_{2.5}$ impacts were accounted for from the Project source using the secondary $PM_{2.5}$ concentrations estimated in Section 6.8. For the NAAQS analysis, a conservative background concentration (see Section 6.9), as provided by ADEM, was added to modeled design short-term and annual impacts to determine compliance.

8.2 Existing Source Inventory

The existing source inventory for this project includes existing sources from Plant Barry along with nearby off-site sources provided by ADEM.

<u>ADEM-provided Sources</u>

An inventory of off-site sources was obtained from ADEM based on significant impact area distances. The significant impact area (SIA) is determined for each pollutant and averaging period that results in a modeled concentration greater than its applicable SIL. The SIA is defined as the further distance from the source that modeled concentrations exceed the SIL.

The SIAs for this project are approximately: 1-km for 1-hour NO_2, 2-km for 24-hour $PM_{2.5}$, and 1-km for annual $PM_{2.5}$. Inventories were provided by ADEM based on these distances or slightly larger distances. A complete background emission inventory of modeled source is provided in the modeling archive (Appendix G).

<u>Existing Plant Barry</u>

Plant Barry operates several permitted electrical generating units including two natural gas-fired power boilers (Units 1 and 2), two coal-fired power boilers (Units 4 and 5), and two 2-on-1 combined-cycle units (Units 6A, 6B, 7A, and 7B). Plant Barry also has additional permitted supporting ancillary

sources including the Unit 5 Auxiliary Boiler, a fuel gas heater, and limestone silo bin vent. Table 8-1 provides the modeled emission rates and stack parameters used in the NAAQS modeling for Plant Barry's existing emission sources.

Table 8-1: Existing Plant Barry Sources Stack Parameters and Emission Rates

Source ID	Source Description	UTM Easting (X) (m)	UTM Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Exhaust Temp (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO_2 (lb/hr)	$PM_{2.5}$ (lb/hr)
Unit1	Gas Boiler	403329.210	3430733.610	6.40	182.9	422.0	4.27	7.82	273.7	10.26
Unit2	Gas Boiler	403329.210	3430733.610	6.40	182.9	422.0	4.27	7.82	276.5	10.37
Unit4	Coal Boiler	403459.000	3430817.000	6.40	182.9	418.2	41.45	4.17	1428.4	151.01
Unit5	Coal Boiler	403707.000	3430757.000	6.71	182.9	331.5	18.29	9.45	3034.16	239.70
Unit6A	CC 6A	402653.000	3430175.000	7.62	36.9	357.6	21.49	5.12	27.7	32.40
Unit6B	CC 6B	402664.000	3430142.000	7.62	36.9	357.6	21.49	5.12	27.7	32.40
Unit7A	CC 7A	402619.000	3430316.000	7.62	36.9	357.6	21.49	5.12	27.7	32.40
Unit7B	CC 7B	402628.000	3430283.000	7.62	36.9	357.6	21.49	5.12	27.7	32.40
U5AuxBlr	Aux Boiler	403832.436	3430783.991	6.40	24.4	422.0	21.21	1.52	55	2.05
FGH	Gas Heater	402394.993	3430209.024	6.40	5.3	510.9	5.79	0.56	1.04	0.08
LSBV	Limestone Silo Bin Vent	403782.796	3430857.105	6.40	60.0	293.2	6.40	1.83	N/A	0.39

8.3 NAAQS Analysis Results

A summary of the NAAQS analysis is presented below in Table 8-2. The modeled concentrations presented represent the Project sources (including the secondary $PM_{2.5}$ estimated in Section 6.8), existing Plant Barry sources, and nearby background sources provided by ADEM. The modeled concentrations were then added to representative ambient background concentrations to estimate the total concentrations that were then compared to the NAAQS. As shown, the total concentrations for 1-hour NO_2 and 24-hour and annual $PM_{2.5}$ are less than the NAAQS. The results of the cumulative modeling analysis show that the Project is in compliance with the applicable NAAQS standards. Figure 8-1 illustrates the results of the 1-hour NO_2 and 24-hour and annual $PM_{2.5}$ NAAQS analyses. As shown in Figure 8-1, all maximum concentrations fall within 100-meter spaced receptors.

Table 8-2: Summary of NAAQS Analysis

Pollutant	Averaging Period	Rank	Modeled Concentration(1) (μg/m³)	Ambient Background Concentration (μg/m³)(2)	Total Concentration (μg/m³)(3)	NAAQS (μg/m³)	Complies (Y/N)?
NO_2	1-hour	98th Percentile Peak Daily 1-hr 5-year Average	85.84 (0.83)	31.0	116.84	189	Yes
$PM_{2.5}$	24-hour(4)	98th Percentile 24-hr 5-year Average	11.51 (0.79)	17.0	28.51	35	Yes
	Annual(4)	5-year Average	2.12 (0.25)	8.1	10.22	12	Yes

(1) Modeled contribution in parentheses represent Project contributions.
(2) Ambient background concentrations take from Table 6-12.
(3) Total concentration includes project, nearby sources, and monitored background concentrations.
(4) Concentrations include secondary $PM_{2.5}$ from Section 6.8.

8.4 PSD Increment Analysis Results

A summary of the PSD increment analysis is presented in Table 8-3 for 24-hour and annual $PM_{2.5}$. A PSD increment modeling analysis was not required for annual NO_2 because the modeled concentrations were less than the SIL. Additionally, there is no PSD increment established for 1-hour NO_2. The modeled concentrations presented in Table 8-3 represent the Project sources (including the secondary $PM_{2.5}$ estimated in Section 6.8), existing Plant Barry $PM_{2.5}$ PSD increment consuming source (Unit 5 Auxiliary Boiler), and nearby background PSD increment consuming sources provided by ADEM. This analysis is conservative in the sense that it did not account for any $PM_{2.5}$ PSD increment expanding sources at Plant Barry or in the inventory provided by ADEM. As shown in Table 8-3, the modeled concentrations for 24-hour and annual $PM_{2.5}$ are less than the PSD increment. The results of the cumulative modeling analysis show that the Project is in compliance with the applicable PSD increments. Figure 8-2 illustrates the results of the 24-hour and annual $PM_{2.5}$ PSD increment analyses. As shown in Figure 8-2, all maximum concentrations fall within 100-meter spaced receptors.

Table 8-3: Summary of PSD Increment Analysis

Pollutant	Averaging Period	Rank	Modeled Concentration (μg/m³)	PSD Increments (μg/m³)	Complies (Yes/No)?
$PM_{2.5}$	24-hour	Highest 2nd Highest over 5 years	4.42	9	Yes
	Annual	Highest Annual Average	0.46	4	Yes

Figure 8-1: NAAQS Analysis Concentration Isopleths (includes ambient background)

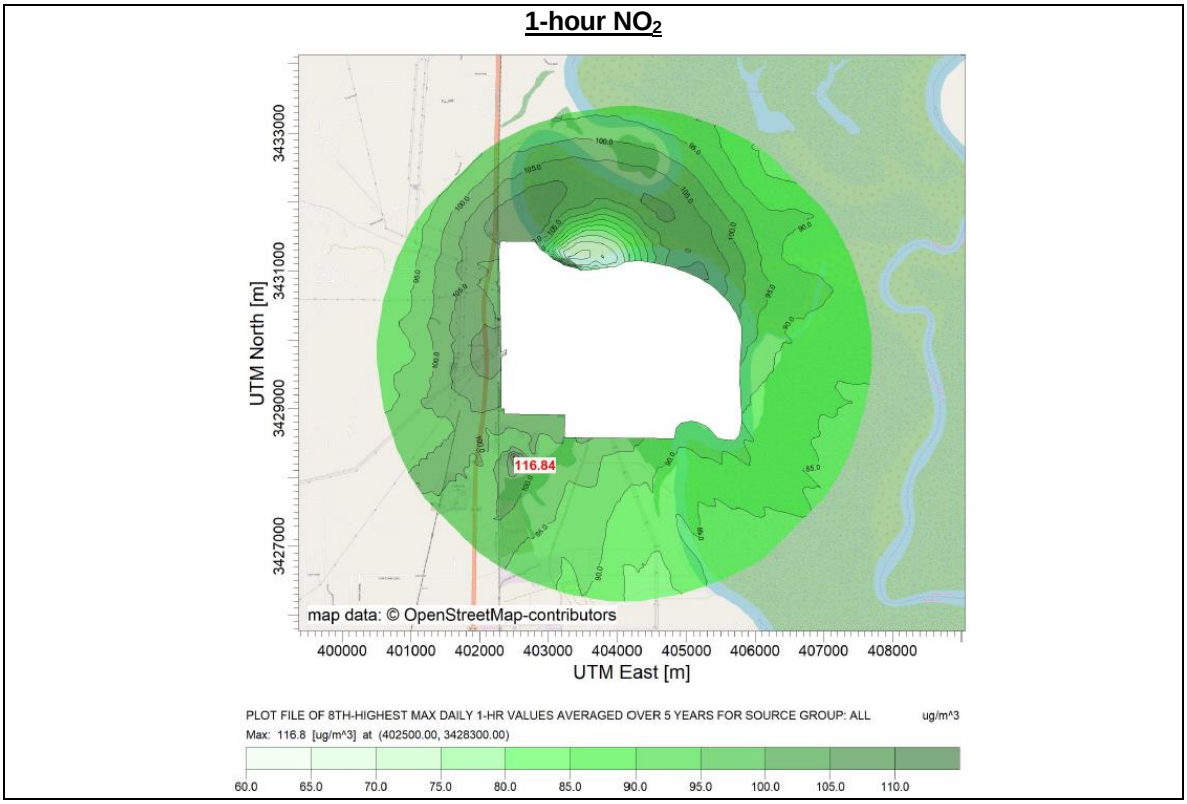
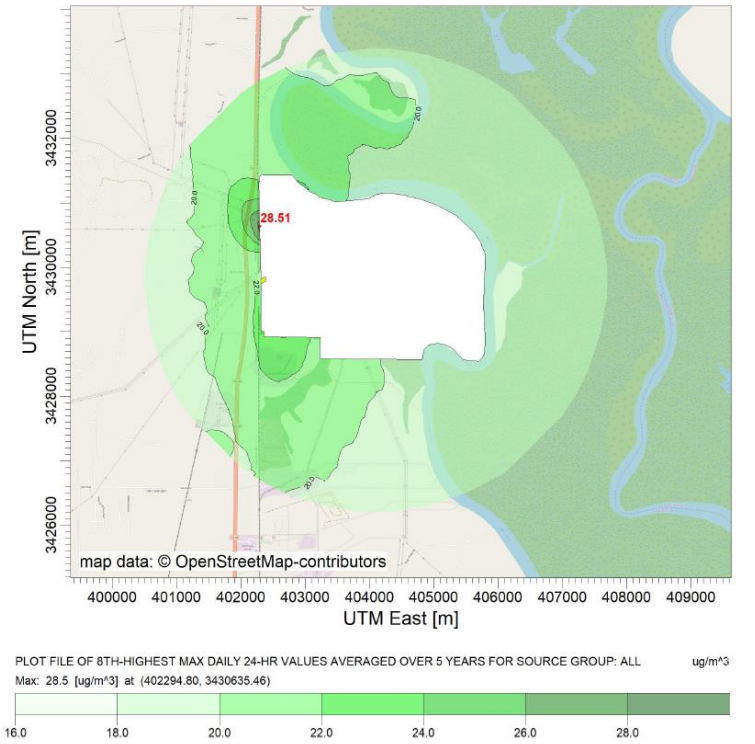


Figure 8-1. continued

24-hour $PM_{2.5}$



Annual $PM_{2.5}$

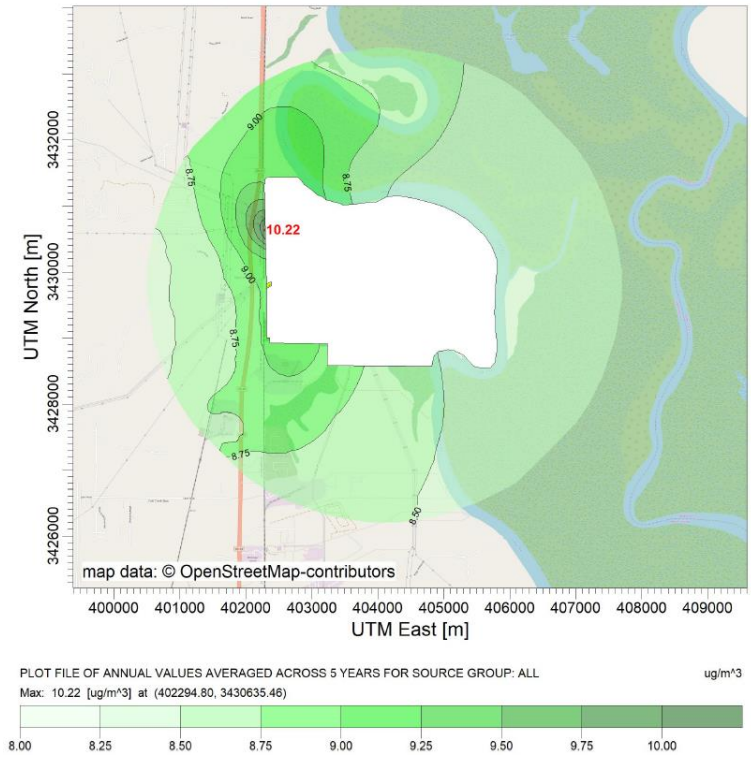
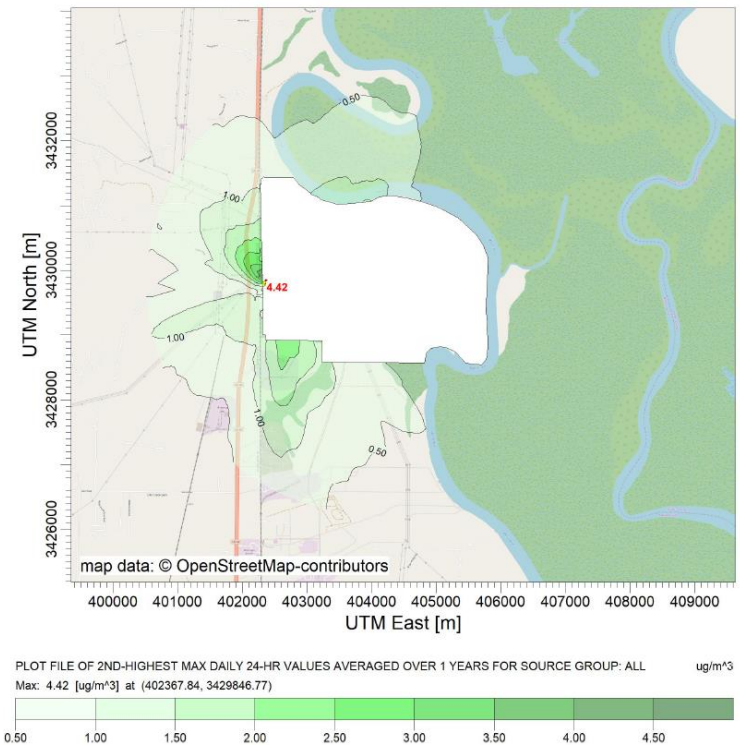
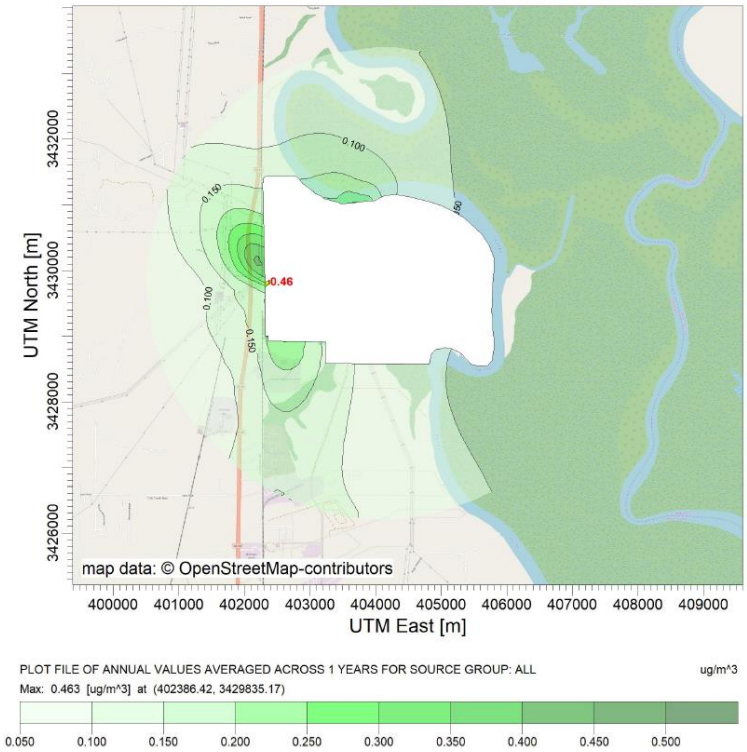


Figure 8-2: PSD Increment Concentration Isopleths

24-hour $PM_{2.5}$



Annual $PM_{2.5}$



9.0 Other Requirements Potentially Applicable to Air Permits Authorizing Construction

9.1 Class I Area Impact Analysis

Federal Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. Proposed major new sources and proposed major modifications to existing sources which will affect a Class I area may need to demonstrate that the PSD Class I increments would not be exceeded, nor would certain air quality-related values (AQRVs) (including visibility) be adversely affected. The nearest PSD Class I area to Plant Barry is Breton National Wildlife Refuge (Breton) located approximately 132 km to the southwest.

There are no PSD increments or air quality related values for CO or VOC. SO_2, NO_2, PM_{10}, and $PM_{2.5}$ are the only other pollutants for which the Project is subject to Class I area review. ADEM has indicated that, because Plant Barry is located more than 100 km from the nearest Class I area (Breton), a Class I increment analysis and NAAQS compliance analysis is not required.

In addition, the Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report (Revised 2010) (FLAG 2010) guidance document, references a Q/D screening approach that is designed to screen out small projects from the need to conduct an AQRV analysis for nearby Class I areas. The **Q** is defined as the Project short-term emission increases expressed in tons. In this case, the "Project" emissions are expressed in terms of the short-term net change in emissions. The **D** is the distance in kilometers from the source to the Class I area. The FLAG guidance suggests and recent experience/discussions with ADEM indicate that if the Q/D ratio is less than ten, the FLM may decide that an analysis of AQRVs (including regional haze and acid deposition) is not necessary.

Based on preliminary estimates, the total sum of the short-term emissions (Q) firing natural gas is 619 tons per year. This number is the sum of the annualized maximum hourly emissions of NOx, SO_2, PM, and H_2SO_4 from the CC unit: NOx = 39.1 lbs/hr/CC, SO_2 = 8.2 lbs/hr/CC, and PM = 21.5 lbs/hr/CC. As stated, the closest Class I area is Breton which located approximately 132 kilometers (D) southwest of Plant Barry. The aforementioned Q and D values result in a Q/D ratio of 4.7. Alabama Power has prepared a Request for Applicability of Class I Area Modeling Analysis which was submitted for review by the Fish and Wildlife Service (FWS) to confirm that Class I modeling will not be required. Alabama Power has yet to receive a response from the FWS.

9.2 Soils and Vegetation

Generally, and unless exempted, an application for an Air Permit Authorizing Construction may also be required to evaluate the impact on soils and vegetation. As required for this Project, an analysis of the Project's potential impact on soils and vegetation in the vicinity of the facility was performed in accordance with the procedures recommended in EPA's *A Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA-450/2-81-078) (EPA 1980) using the SIL modeling approaches as described in Section 7.

The highest modeled concentrations of NO_2, SO_2, and CO from this project were compared to the screening concentrations as shown in Table 9-1. As shown, the modeled concentrations are all well

below their screening thresholds, therefore, no significant impacts on local vegetation is expected as a result of the Project.

Table 9-1: Injury Threshold for Vegetation

Pollutants	Averaging Period	Maximum Modeled Concentration (µg/m3)	EPA's 1980 Screening(2) Concentration (µg/m^3)
SO_2	Annual[3]	0.1	18
	3-hour[3]	2.5	786
	1-hour[3]	2.51	917
NO_2(1)	Annual[3]	0.73	94
	4-hour[3]	11.02	3,760
	1-month[4]	7.70	564
CO	Weekly[4]	15.64	1,800,000

(1) Modeled NO_2 concentrations were estimated by scaling the NO_X concentration by 0.9, the upper limit of ARM2.
(2) Source: "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals". EPA 450/2-81-078, December 1980.
(3) Values based on SIL modeling presented in Table 7.4. Additional model iterations were performed for averaging periods not associated with the SIL modeling.
(4) 24-hour averaging period model results were conservatively used to demonstrate compliance with these long-term averaging periods associated with the 1-month and weekly screening level criteria.

There is no corresponding screening threshold for PM_{10} and $PM_{2.5}$. Therefore, the demonstration of compliance with the PM_{10} and $PM_{2.5}$ NAAQS serves as a suitable surrogate for the evaluation of impacts to soils and vegetation. In addition, demonstration of compliance with the 24-hour PM_{10}/$PM_{2.5}$ and 1-hour NO_2 NAAQS would also indicate that the Project should not have any nearby impacts associated with visible plumes.

9.3 Growth Related Impacts

Generally, and unless exempted, an application for an Air Permit Authorizing Construction may also be required to conduct a qualitative evaluation of the general commercial, residential, industrial and other growth associated with the Project.

The proposed project is not expected to employ additional employees at this time. Therefore, secondary growth is not expected, and thus an analysis of such growth was not performed.

10.0 References

ADEM, 2019. PSD Air Quality Analysis Modeling Guidelines (March 2019). The Alabama Department of Environmental Management Air Division Planning Branch Meteorological Section. http://www.adem.state.al.us/programs/air/airquality/AeromodModelingGuidelines.pdf

National Park Service, 2010. Phase I Report of the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Revised 2010. National Park Service, Air Resources Division; U.S. Forest Service, Air Quality Program; U.S. Fish and Wildlife Service, Air Quality Branch. http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf.

US EPA 1980. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals. EPA-450/2-81-078. US EPA, Research Triangle Park, NC 27711.

US EPA 1985. Guideline for the Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) - Revised. EPA-450/4-80-023R, US EPA, Research Triangle Park, NC 27711.

US EPA 2010. Modeling Procedures for Demonstrating Compliance with the $PM_{2.5}$ NAAQS. (March 23, 2010). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Available at: http://www.epa.gov/ttn/scram/Official%20Signed%20Modeling%20Proc%20for%20 Demo%20Compli%20w%20PM2.5.pdf

US EPA 2011. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS. (March 1, 2011). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Available at: http://www.epa.gov/ttn/scram/Additional_Clarifications_ AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

US EPA 2008. AERSURFACE User's Guide. EPA-454/B-08-001 (January 2008, Revised 1/16/2013). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2017. Guideline on Air Quality Models (Revised). Codified in the Appendix W to 40 CFR Part 51. Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2017.

US EPA 2019a. User's Guide for the AMS/EPA Regulatory Model (AERMOD). EPA-454/B-19-027 (August 2019). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2019b. User's Guide for the AERMOD Meteorological Preprocessor (AERMET). EPA-454/B-19-028 (August 2019). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2018a. AERMOD Implementation Guide. EPA-454-B-18-003 (April 2018) US EPA, Research Triangle Park, NC.

US EPA 2018b. User's Guide for the AERMOD Terrain Preprocessor (AERMAP). EPA-454/B-18-004 (April 2018). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

Appendix A

Application Forms

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT (AIR DIVISION)

Do not Write in This Space

Facility Number [ ][ ][ ] - [ ][ ][ ][ ]

CONSTRUCTION/OPERATING PERMIT APPLICATION
FACILITY IDENTIFICATION FORM

1. **Name of Facility, Firm, or Institution:** Alabama Power Company - Barry Steam Electric Generating Plant

Facility Physical Location Address

Street & Number: 15300 Highway 43 North

City: Bucks **County:** Mobile **Zip:** 36512-0070

Facility Mailing Address (If different from above)

Address or PO Box: P.O. Box 70

City: Bucks **State:** Alabama **Zip:** 36512-0070

Owner's Business Mailing Address

2. **Owner:** Alabama Power Company

Street & Number: P.O. Box 2641 **City:** Birmingham

State: Alabama **Zip:** 35291-0830 **Telephone:** (205) 257-1000

Responsible Official's Business Mailing Address

3. **Responsible Official:** Mike Godfrey **Title:** Manager, Environmental Compliance

Street & Number: P.O. Box 2641

City: Birmingham **State:** Alabama **Zip:** 35291-0830

Telephone Number: (205) 257-6131 **E-mail Address:** jgodfrey@southernco.com

Plant Contact Information

4. **Plant Contact:** Clyde Bo Cotton, Jr. **Title:** Senior Compliance Specialist

Telephone Number: (251) 829-2763 **E-mail Address:** cbcotton@southernco.com

5. **Location Coordinates:**

UTM Easting 403.550 kilometers **E-W** Northing 3,430.450 kilometers **N-S**

Latitude/Longitude _____ **LAT** _____ **LONG**

6. **Permit application is made for:**

- ☐ **Existing source (initial application)**
- ☐ **Modification**
- ☑ **New source (to be constructed)**
- ☐ **Change of ownership**
- ☐ **Change of location**
- ☐ **Other (specify)** _____

Existing source (permit renewal)

If application is being made to construct or modify, please provide the name and address of installer or contractor

Mitsubishi Hitachi Power Systems Americas, Inc. 400 Colonial Center Parkway, Suite 400 Lake Mary, FL 32746

Black & Veatch Corporation 11401 Lamar Ave. Overland Park KS 66211

_____ **Telephone** _____

Date construction/modification to begin March 2021 **to be completed** August 2029

7. **Permit application is being made to obtain the following type permit:**

- ☑ **Air permit**
- ☐ **Major source operating permit**
- ☐ **Synthetic minor source operating permit**
- ☐ **General permit**

8. **Indicate the number of each of the following forms attached and made a part of this application: (if a form does not apply to your operation indicate "N/A" in the space opposite the form). Multiple forms may be used as required.**

3	**ADEM 104 - INDIRECT HEATING EQUIPMENT**
1	**ADEM 105 - MANUFACTURING OR PROCESSING OPERATION**
-	**ADEM 106 - REFUSE HANDLING, DISPOSAL, AND INCINERATION**
5	**ADEM 107 - STATIONARY INTERNAL COMBUSTION ENGINES**
-	**ADEM 108 - LOADING, STORAGE & DISPENSING LIQUID & GASEOUS ORGANIC COMPOUNDS**
-	**ADEM 109 - VOLATILE ORGANIC COMPOUND SURFACE COATING EMISSION SOURCES**
4	**ADEM 110 - AIR POLLUTION CONTROL DEVICE**
-	**ADEM 112 - SOLVENT METAL CLEANING**
4	**ADEM 438 - CONTINUOUS EMISSION MONITORS**
	ADEM 437 - COMPLIANCE SCHEDULE

9. **General nature of business: (describe and list appropriate standard industrial classification (SIC) and North American Industry Classification System (NAICS) (www.naics.com) code(s)):**

SIC: Major Group 49 – Electric, Gas, and Sanitary Services, Electric Services – 4911

NAICS: 221112, Fossil Fuel Electric Power Generation

10. **<u>For those making application for a synthetic minor or major source operating permit</u>, please summarize each pollutant emitted and the emission rate for the pollutant. Indicate those pollutants for which the facility is major.**

Regulated pollutant	Potential Emissions* (tons/year)	Major source? yes/no

***Potential emissions are either the maximum allowed by the regulations or by permit, or, if there is no regulatory limit, it is the emissions that occur from continuous operation at maximum capacity.**

11. For those applying for a major source operating permit, indicate the compliance status by program for each emission unit or source and the method used to determine compliance. Also cite the specific applicable requirement.

Emission unit or source: _____
(description)

Emission Point No.	Pollutant[4]	Standard	Program[1]	Method used to determine compliance	Compliance Status	
					IN[2]	OUT[3]

[1]PSD, non-attainment NSR, NSPS, NESHAP (40 CFR Part 61), NESHAP (40 CFR Part 63), accidental release (112(r)),SIP regulation, Title IV, Enhanced Monitoring, Title VI, Other (specify)

[2]Attach compliance plan

[3]Attach compliance schedule (ADEM Form-437)

[4]Fugitive emissions must be included as separate entries

12. **List all insignificant activities and the basis for listing them as such (i.e., less than the insignificant activity thresholds or on the list of insignificant activities). Attach any documentation needed, such as calculations. No unit subject to an NSPS, NESHAP or MACT standard can be listed as insignificant.**

Insignificant Activity	Basis

13. List and explain any exemptions from applicable requirements the facility is claiming:

a. See, Technical Support Document.

b.

c.

d.

e.

f.

g.

h.

i.

14. List below other attachments that are a part of this application(all supporting engineering calculations must be appended):

a. Technical Support Document

b. Emissions Calculations

c. PSD Permit Limits from EPA's RACT/BACT/LAER Clearinghouse

d. Plot Plan

e. GEP Documentation for Barry Units 1-2 Common Stack, GEP Documentation for the Plant Barry Unit 4 and Unit 5 Stacks

f. Land Use Analysis

g. Air Dispersion Modeling Files

h. Concentration Isopleths

i. AQS Reports

I CERTIFY UNDER PENALTY OF LAW THAT, BASED ON INFORMATION AND BELIEF FORMED AFTER REASONABLE INQUIRY, THE STATEMENTS AND INFORMATION CONTAINED IN THIS APPLICATION ARE TRUE, ACCURATE AND COMPLETE.

I ALSO CERTIFY THAT THE SOURCE WILL CONTINUE TO COMPLY WITH APPLICABLE REQUIREMENTS FOR WHICH IT IS IN COMPLIANCE, AND THAT THE SOURCE WILL, IN A TIMELY MANNER, MEET ALL APPLICABLE REQUIREMENTS THAT WILL BECOME EFFECTIVE DURING THE PERMIT TERM AND SUBMIT A DETAILED SCHEDULE, IF NEEDED FOR MEETING THE REQUIREMENTS.

SIGNATURE OF RESPONSIBLE OFFICIAL **TITLE** **DATE**

PROJECT INFORMATION SHEET

PROJECT NAME: Alabama Power Company - Plant Barry Combined Cycle Project

PROJECT DESCRIPTION, INCLUDING NATURE OF PROJECT (i.e., New or Modified facility):

Alabama Power Company plans to construct two natural gas-fired combined cycle (CC) units, each with a CTG and HRSG. See the Project Description for additional details on the CC units and ancillary equipment proposed with this project.

PROJECT LOCATION (i.e., STATE, COUNTY, NEAREST CITY; UTM COORDINATES):

Plant Barry is located in Bucks, Alabama in Mobile County. The UTM coordinates of the approximate center of the proposed plant are: Easting: 403,550 meters; Universal Transverse Mercator (UTM) Northing: 3,430,450 meters; UTM Zone: 16.

LIST OF CLASS I AREAS WITHIN 100 KM OF THE PROPOSED SOURCE OR THOSE THAT THE PERMITTING AUTHORITY BELIEVES MAY BE IMPACTED BY A LARGE SOURCE WHICH IS BEYOND 100 KM. INCLUDE DISTANCE AND DIRECTION FROM THE CLASS I AREAS TO THE SOURCE:

The only PSD Class I area to Plant Barry is Breton National Wildlife Refuge (Breton) located approximately 132 km to the southwest.

PROPOSED EMISSION RATES AND/OR INCREASES:

EMISSIONS	lb/hr	TPY
SO_2		70.9
NO_X		350.2
PM		189.7
CO		520.7
VOC		383.4
Other (List)		
Other (List)		
Other (List)		

PROPOSED EMISSION CONTROL TECHNOLOGY AND PROPOSED REMPOVAL EFFICIENCY/EMISSION RATE (USING RBLC STANDARD UNITS, i.e., ppm, lb/MMBtu)

See, Technical Support Document.

BRIEF SUMMARY OF ANY CLASS I ANALYSES CONTAINED IN THE APPLICATION (E.g., INCREMENT CONSUMPTION, VISIBILITY, DEPOSITION ANALYSES)

There are no PSD increments or air quality related values for CO or VOC. ADEM has indicated that, because Plant Barry is located more than 100 km from the nearest Class I area (Breton), a Class I increment analysis and NAAQS compliance analysis is not required.

COMPANY CONTACT: Mike Godfrey

MAILING ADDRESS:

P.O. Box 2641
Birmingham, Alabama 35203

TELEPHONE AND FAX NUMBERS:

(205) 257-6131

STATE CONTACT: **TIM OWEN, CHIEF, ENGINEERING BRANCH**

MAILING ADDRESS: **ADEM - AIR DIVISION**
P.O. BOX 301463
MONTGOMERY, AL 36130-1463

TELEPHONE AND FAX NUMBERS: **334/271-7861 (PHONE)**
334/279-3044 (FAX)

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
PERMIT APPLICATION FOR
STATIONARY INTERNAL COMBUSTION ENGINES

___ — ____ — ____

Permit Number (ADEM Use Only)

1. Facility Name: Alabama Power Company - Barry Steam Electric Generating Plant **Location:** Bucks, Mobile County, Alabama

2. Purpose of Application:

- [x] Initial installation of a new engine (i.e. engine that has never been in service at any location)
- [ ] Initial installation of a used engine (i.e. an engine that has been in service at another location)
- [ ] Modification/Reconstruction of an engine currently installed at the facility
- [ ] Update information for an engine currently installed at the facility
- [ ] Title V Application
- [ ] Other, please describe: _____

If this application is for the installation, modification, or reconstruction of an engine, please provide the date construction is scheduled to begin: First Quarter 2021

If this application is for an engine currently installed at this facility, please provide the date that the engine was initially installed at this facility: _____

3. Engine Identification:

A. Manufacturer's Name: Mitsubishi Hitachi Power Systems Americas Inc. B. Model Number: M501JAC C. Model Year: TBD

D. Facility's Identification Number or Description: Unit 8 Combustion Turbine E. Serial Number: _____

4. Engine Applicability Dates:

A. For a new engine, Date Ordered: _____ B. Date Manufactured: TBD C. Date Modified/Reconstructed: _____

D. For a used engine, approximate date engine was first placed into service at any location: _____

Engine Function: [ ] Compression [x] Electrical Generation (Maximum Electrical Output: 457 MW) [ ] Fire Pump Driver [ ] Other Pump Driver [ ] Research & Development [ ] Test Cell/Stand [ ] Other, please describe: _____

6. Engine Operation: [ ] Emergency Only [x] Non-emergency, please provide typical operating schedule in Items A-D below:

[ ] Limited Use (<100 hr/yr) A. Hours Per Day: 24 B. Days Per Week: 7 C. Weeks per Year: 52

D. Peak Season (if any): _____

7. Engine Specifications:

A. Maximum Brake Horsepower (bhp): _____ B. Maximum Engine Power (kW_m): _____ C. Maximum Heat Input (MMBtu/hr): 3,987

D. Type: [ ] Simple Cycle Turbine [x] Combined Cycle Turbine [ ] Regenerative Cycle Turbine [ ] Reciprocating Engine

E. Piston Movement: [ ] 2-Stroke RICE [ ] 4-Stroke RICE [x] N/A [ ] Other: _____

F. Air/Fuel Mix: [ ] Rich Burn RICE [ ] Lean Burn RICE [ ] Diffusion Flame Turbine [x] Lean Premix Turbine [ ] Other: _____

G. Ignition Type: [ ] Spark [ ] Compression [x] N/A H. Cylinder Displacement (Liters per cylinder): _____

8. Fuel Information:

	Fuel Type/Description	Sulfur Content (indicate % by weight OR ppm)	Fuel-bound Nitrogen Content (indicate % by weight OR ppm)	Percent (%) of Gross Heat Input on Annual Basis
Primary Fuel	Natural Gas	0.6 gr/100 scf		100
Secondary/Backup				

9. Stack Parameters (if a control device is installed, the information should be for the control device's stack exit):

A. Height above grade (feet): 180 B. Inside Diameter at Exit (feet): 23.0 C. Exhaust Gas Volume (ACFM): 1,724,815

D. Base Elevation (feet): ~25 E. Exhaust Gas Temperature°F): 179 F. Are sampling ports available? (•) Yes ( ) No

G. UTM Coordinate (E-W) (km): 402.497 H. UTM Coordinate (N-S) (km): 3,429.759

10. Point Source Emissions (You must attach calculations and, if used as the basis for emission estimates, manufacturer specification sheets):

Pollutant	Uncontrolled[1] Potential Emission Rate		Controlled[1,2] Potential Emission Rate		Basis for Potential Emissions Calculation/Estimate (e.g. AP-42, Manufacturer Data)	Comment (Optional)
	lb/hr	ton/yr	lb/hr	ton/yr		
NOx						See Emissions Calculations in Appendix D.
CO						See Emissions Calculations in Appendix D.
VOC						See Emissions Calculations in Appendix D.
PM						See Emissions Calculations in Appendix D.
SO_2						See Emissions Calculations in Appendix D.
Formaldehyde						See Emission Calculations in Appendix D
Total HAP						See Emission Calculations in Appendix D

[1]Potential emissions should be calculated based on 8,760 hr/yr and maximum operation unless an enforceable limit will be applicable.

[2]If the pollutant is uncontrolled, leave blank.

11. Applicable Regulations (Mark all that apply):

- ☐ 40 CFR 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines
- ☐ 40 CFR 60, Subpart GG, NSPS for Stationary Gas Turbines
- ☒ 40 CFR 60, Subpart KKKK, NSPS for Stationary Combustion Turbines
- ☐ Other: _____
- ☐ 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE
- ☐ 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition ICE
- ☐ 40 CFR 60, Subpart JJJJ, NSPS for Stationary Spark Ignition ICE
- ☐ Other: _____

12. Regulatory Standards, Limitations, and Requirements:

A.

Pollutant/Parameter	Rate/Value	Units of Standard	Regulatory Basis[3]	Engine Potential Emission Rate (in units of standard)
Example: NOx + NMHC	*6.4*	*g/kW-hr*	*NSPS, Subpart IIII*	*4.95 g/kW-hr*
Example: Annual Operation	*6,000*	*hr/yr*	*SMS-PSD*	*NA*
NOx	4	ppmvd @15% O2	ADEMAdmin.Code335-3-8.06(3)	See Calculations in Appendix D
NOx	15	ppmvd @15% O2	40 CFR Part 60, Subpart KKKK	See Calculations in Appendix D
SO2	0.060	lb/MMBtu	40 CFR Part 60, Subpart KKKK	See Calculations in Appendix D

[3]For federal regulations, specify which NSPS or NESHAP is the basis. If a synthetic minor limit is being requested or is already applicable, specify either SMS-PSD or SMS-Title V

B. For engines subject to emission standards under NSPS, Subpart IIII or NSPS, Subpart JJJJ, is this engine certified by the manufacturer pursuant to the applicable regulation to meet the applicable emission standards ? ◉ N/A ○ No ○ Yes (If yes, attach a copy of the certification)

C. For emergency or limited use engines, is this engine equipped with a non-resettable hour meter? ◉ N/A ○ No ○ Yes

13. Pollution Control Information:

A. Device/Technology Type(s):

- [ ] No Controls
- [ ] Air-to-Fuel Ratio Controller
- [ ] Water or Steam Injection
- [x] Low NO_X Burners
- [x] Oxidation Catalyst
- [ ] Selective Non-catalytic Reduction (SNCR)
- [ ] Non-selective Catalytic Reduction (NSCR/3-way Catalyst)
- [x] Selective Catalytic Reduction (SCR)
- [ ] Other: _____
- [ ] Other: _____
- [ ] Other: _____

B. Control Efficiencies (Typical Operation)

Pollutant	% Reduction
NOx	
CO	
VOC	
Formaldehyde	

C. Operational Parameters (if any):

14. Compliance Status:

Is this engine in compliance with all applicable air pollution rules and regulations? (•) Yes ( ) No (If "No", must attach ADEM Form 437)

15. Clarifying/Supplemental Information (Optional):

For additional information, see Technical Support Document.

Please provide the following for the person preparing this application:

Name (Print or Type): Nikia Howard Company/Affiliation: _____

Signature: Nikia Howard Date: 2/18/2020

PERMIT APPLICATION
FOR
INDIRECT HEATING EQUIPMENT
(FUEL BURNING EQUIPMENT)

☐☐☐ - ☐☐☐☐ - ☐☐☐☐
Do not write in this space

1. **Name of firm or organization:** Alabama Power Company - Barry Steam Electric Generating Plant

2. **Unit Description (i.e. No. 1 Power Boiler):** Unit 8 Duct Burner

Equipment manufacturer's information

Name of manufacturer: TBD

Model number: _____

Rated capacity-input: 917 million (Btu/hr.)

Boiler type: ☐ Fire tube ☐ Water tube ☐ other(specify): _____

Manufactured date: _____

Proposed installation date: _____

Original installation date (if existing): _____

Reconstruction or Modification date (if applicable): _____

3. **Type of fuel used:**

Primary:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas	1020	Btu/ft^3	0.6 gr/100 scf			
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

Standby:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas		Btu/ft^3				
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

4. Purpose (if multipurpose, note percent in each use category):

☐Space heat _____ % ☑Power generation 100 % ☐Process heat %

Other (specify): _____

5. Normal schedule of operation:

Hours per day: 24 Days per week: 7 Weeks per year: 52

6. For each regulated pollutant, describe any limitations on source operation which affects emissions or any work practice standard (attach additional page if necessary):

N/A

7. Fugitive Emissions (attach calculation worksheets):

POLLUTANT	POTENTIAL EMISSIONS lb/hr	POTENTIAL EMISSIONS t/yr	BASIS OF CALCULATION	REGULATORY EMISSION LIMIT (lb/hr)	REGULATORY EMISSION LIMIT (in units of standard)
Particulate					
Sulfur dioxide					
Nitrogen oxides					
Carbon monoxide					
VOC's					
Other					

8. Is there any emission control equipment on this emission source?

☑Yes ☐No (If "yes", complete ADEM Form 110)

9. Point Emissions (attach calculation worksheets):

POLLUTANT	POTENTIAL EMISSIONS lb/hr	POTENTIAL EMISSIONS t/yr	BASIS OF CALCULATION	REGULATORY EMISSION LIMIT (lb/hr)	REGULATORY EMISSION LIMIT (in units of standard)
Particulate				See Emissions Calculations	in Appendix D.
Sulfur dioxide				See Emissions Calculations	in Appendix D.
Nitrogen oxides				See Emissions Calculations	in Appendix D.
Carbon monoxide				See Emissions Calculations	in Appendix D.
VOC's				See Emissions Calculations	in Appendix D.
Other					

10. Stack data:

UTM Coordinate (E-W) 402.497 (km) UTM Coordinate (N-S) 3,429.759 (km)

Height above grade 180 (feet) Gas temperature at exit 179 (°F)

Inside diameter at exit 23.0 (feet) Volume of gas discharged 1,724,815 (ACFM)

Base Elevation ~25 (feet)

Are sampling ports available? ◉ Yes ○ No (If "yes", describe. Draw on separate sheet if necessary):

11. Is this item in compliance with all applicable air pollution rules and regulations?

◉ Yes ○ No (if "no", a compliance schedule, ADEM Form 437, must be attached.)

Name of person preparing application: Nikia Howard

Signature: Nikia Howard Date: 2/18/2020

ADEM

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

PERMIT APPLICATION

FOR

AIR POLLUTION CONTROL DEVICE

☐☐☐ - ☐☐☐☐ - ☐☐☐☐
(ADEM Use Only)

1. **Name of firm or organization** Alabama Power Company - Barry Steam Electric Generating Plant

2. **Type of pollution control device: (if more than one, check each; however, separate forms are to be submitted for each specific device.)**

   ☐ Settling chamber ☐ Electrostatic precipitator
   ☐ Afterburner ☐ Baghouse
   ☐ Cyclone ☐ Multiclone
   ☐ Absorber ☐ Adsorber
   ☐ Condenser ☐ Wet Suppression

   Wet scrubber (kind): _____

   Stage 1 - Vapor balance (type): _____

   Other (describe): Selective Catalytic Reduction (SCR)

3. **Control device manufacturer's information:**

   Name of manufacturer TBD Model No. _____

4. **Emission source to which device is installed or is to be installed:**

   Unit 8

5. **Emission parameters:**

	Pollutants Removed		
	Pollutant #1	Pollutant #2	Pollutant #3
	NOx		
Mass emission rate (#/hr)			
Uncontrolled	See Emissions Calculations	in Appendix D.	
Designed			
Manufacturer's guaranteed			
Mass emission rate (Expressed as units of standard)			
Required by regulation			
Manufacturer's guaranteed			
Removal efficiency (%)			
Designed			
Manufacturer's guaranteed			

6. Gas conditions:

	Inlet	Intermediate Locations	Outlet
Volume (SDCFM, 68°f, 29.92" hg)			
(ACFM, existing conditions)			1,724,815
Temperature (°F)			179
Velocity (ft/sec)			69.19
Percent moisture			9.70

Pressure drop across device: _____ (inches H_20)

7. Stack dimensions:

UTM Coordinates (E-W)..... 402.497 (km)

UTM Coordinates (N-S)..... 3,429.759 (km)

Height above grade ..... 180 (feet)

Inside diameter at exit (if opening is round)..... 23 (feet)

Inside area at exit (if opening is not round) ..... _____ (sq. feet)

Base Elevation..... ~25 (feet)

GEP Stack Height ..... 213 (feet)

8. Provide a flow diagram which includes gas exit from process, each control device, location of by-pass, fan or blower, each emission point, exits for collected pollutants, and location of sampling ports.

See Attached.

9. Enclosed are:

☐ Blueprints ☐ Particle size distribution report

☐ Manufacturer's literature ☐ Size-efficiency curves

☐ Emissions test of existing installation ☐ Fan curves

☒ Other Enclosed emissions calculations provide further details.

10. If the pollution control device is of unusual design, please provide a sketch of the device.

11. List below the important operating parameters for the device. (For example: air/cloth ratio and fabric type, weight, and weave for baghouse; throat velocity and water use rate for a venturi scrubber; etc.)

Ammonia injection is controlled to maintain the desired NOx emission rate.

12. By-pass (if any) is to be used when:

N/A

13. Disposal of collected air pollutants:

	Solid waste	Solid waste	Liquid waste	Liquid waste
Volume				
Composition				
Is waste hazardous?				
Method of disposal				
Final destination				

If collected air pollutants are recycled, describe:

Name of person preparing application Nikia Howard

Signature Nikia Howard Date 2/18/2020

ADEM

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

PERMIT APPLICATION

FOR

AIR POLLUTION CONTROL DEVICE

☐☐☐ - ☐☐☐☐ - ☐☐☐☐
(ADEM Use Only)

1. Name of firm or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. Type of pollution control device: (if more than one, check each; however, separate forms are to be submitted for each specific device.)

   ☐ Settling chamber ☐ Electrostatic precipitator
   ☐ Afterburner ☐ Baghouse
   ☐ Cyclone ☐ Multiclone
   ☐ Absorber ☐ Adsorber
   ☐ Condenser ☐ Wet Suppression

   Wet scrubber (kind): _____

   Stage 1 - Vapor balance (type): _____

   Other (describe): Oxidation Catalyst System

3. Control device manufacturer's information:

   Name of manufacturer: TBD Model No. _____

4. Emission source to which device is installed or is to be installed:

   Unit 8

5. Emission parameters:

	Pollutants Removed		
	Pollutant #1	Pollutant #2	Pollutant #3
	CO	VOC	
Mass emission rate (#/hr)			
Uncontrolled	See Emissions Calculations	in Appendix D.	
Designed			
Manufacturer's guaranteed			
Mass emission rate (Expressed as units of standard)			
Required by regulation			
Manufacturer's guaranteed			
Removal efficiency (%)			
Designed			
Manufacturer's guaranteed			

6. Gas conditions:

	Inlet	Intermediate Locations	Outlet
Volume (SDCFM, 68°f, 29.92" hg)			
(ACFM, existing conditions)			1,724,815
Temperature (°F)			179
Velocity (ft/sec)			69.19
Percent moisture			9.70

Pressure drop across device: _____ (inches H_20)

7. Stack dimensions:

UTM Coordinates (E-W)..... 402.497 (km)

UTM Coordinates (N-S)..... 3,429.759 (km)

Height above grade ..... 180 (feet)

Inside diameter at exit (if opening is round)..... 23 (feet)

Inside area at exit (if opening is not round) ..... _____ (sq. feet)

Base Elevation..... ~25 (feet)

GEP Stack Height ..... 213 (feet)

8. Provide a flow diagram which includes gas exit from process, each control device, location of by-pass, fan or blower, each emission point, exits for collected pollutants, and location of sampling ports.

See Attached.

9. Enclosed are:

☐ Blueprints ☐ Particle size distribution report

☐ Manufacturer's literature ☐ Size-efficiency curves

☐ Emissions test of existing installation ☐ Fan curves

☒ Other Enclosed emissions calculations provide further details.

10. If the pollution control device is of unusual design, please provide a sketch of the device.

11. List below the important operating parameters for the device. (For example: air/cloth ratio and fabric type, weight, and weave for baghouse; throat velocity and water use rate for a venturi scrubber; etc.)

12. By-pass (if any) is to be used when:

N/A

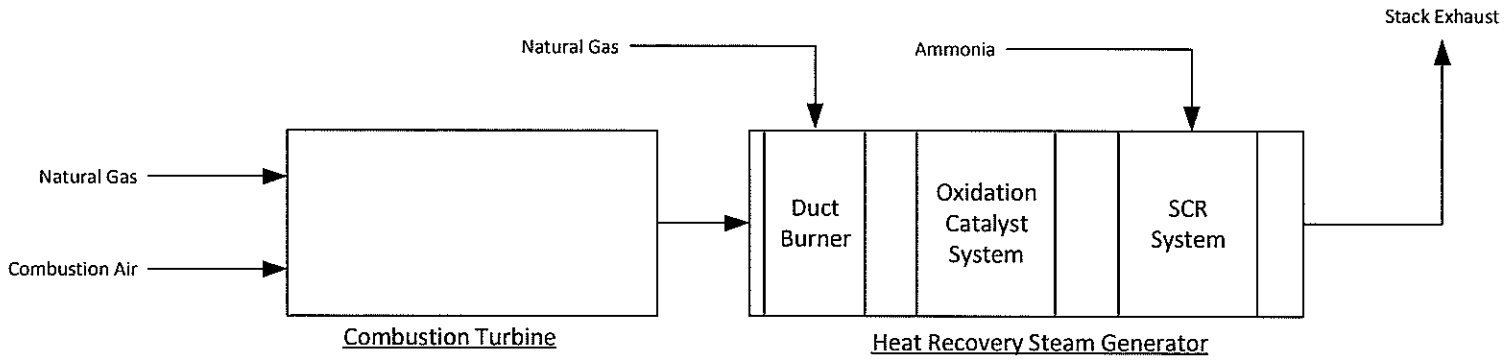
13. Disposal of collected air pollutants:

	Solid waste	Solid waste	Liquid waste	Liquid waste
Volume				
Composition				
Is waste hazardous?				
Method of disposal				
Final destination				

If collected air pollutants are recycled, describe:

Name of person preparing application Nikia Howard

Signature Nikia Howard Date 2/18/2020



COMBUSTION TURBINE/HRSG FLOW DIAGRAM

PERMIT APPLICATION
FOR
CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

[ ][ ][ ] - [ ][ ][ ][ ] - [ ][ ][ ][ ]
Do not write in this space

1. Name of firm or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. List pollutant or parameter the continuous emission monitoring system is measuring:

- ☐ Sulfur dioxide
- ☑ Nitrogen oxides
- ☐ PM10
- ☐ Oxygen
- ☐ Pressure
- ☐ Carbon dioxide
- ☐ Carbon monoxide
- ☐ Particulates
- ☐ Exhaust temperature
- ☐ Hydrogen chloride
- ☐ Opacity
- ☐ Temperature
  - ☐ Exhaust gas
  - ☐ Primary Chamber
  - ☐ Secondary chamber
- ☐ Total reduced sulfides
- ☐ Hydrogen sulfide
- ☐ Flow rate
- ☐ VOCs
- ☐ Other (explain): _____

3. CEMS Manufacturer's information:

Name of manufacturer: TBD

Model number: _____

Serial number: _____

4. Data acquisition system to be used (data logger, strip chart, etc.):

Name of manufacturer: TBD

Model number: _____

Serial number: _____

5. Indicate emission source to be monitored and the location of the specific CEM:

Unit 8

Monitor to be located in the CEMS building, probe to be located in the stack.

6. **Briefly describe the calibration and operational procedures to be used in operating the CEM: (indicate estimate of time lost in calibrating, maintaining, repairing, etc.)**

The computer system will provide automated daily zero/span checks. No lost time to occur due to the daily zero/span checks. We expect between 2-5% lost time due to repairs and maintenance.

7. **Indicate CEM calibration/maintenance schedule:** Calibration/maintenance schedules performed will be described in the Quality Assurance Plan. This will provide for daily, weekly, quarterly, and annual maintenance. CEMS audits will be conducted semi-annually or annually. Other maintenance repairs will be performed as necessary.

8. **Check which program(s) apply to the unit with the monitor:**

☑ NSPS ☑ SIP ☑ PSD ☐ BIF

☐ NESHAPS ☑ Acid Rain ☐ RCRA ☑ Enhanced Monitoring

9. **Monitor span: From:** _____ **To:** _____

10. **Performance protocol (from Appendix B in 40 CFR Part 60):** Performance Specification 2

11. **Insitu/dilution extractive/extractive? (type):** Dilution Extractive

12. **If dilution extractive, give approximate dilution rate:** _____

13. **Conditioning system?** ☑ yes ☐ no

If yes, what type? Dilution Air Conditioning System

14. **Does Appendix F in 40 CFR Part 60 apply?** ☑ yes ☐ no

Name of person preparing application: Nikia Howard

Signature: Nikia Howard **Date:** 2/18/2020

PERMIT APPLICATION
FOR
CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

☐☐☐ - ☐☐☐☐ - ☐☐☐☐
Do not write in this space

1. Name of firm or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. List pollutant or parameter the continuous emission monitoring system is measuring:

- ☐ Sulfur dioxide
- ☐ Nitrogen oxides
- ☐ PM10
- ☐ Oxygen
- ☐ Pressure
- ☑ Carbon dioxide
- ☐ Carbon monoxide
- ☐ Particulates
- ☐ Exhaust temperature
- ☐ Hydrogen chloride
- ☐ Opacity
- ☐ Temperature
  - ☐ Exhaust gas
  - ☐ Primary Chamber
  - ☐ Secondary chamber
- ☐ Total reduced sulfides
- ☐ Hydrogen sulfide
- ☐ Flow rate
- ☐ VOCs
- ☐ Other (explain): _____

3. CEMS Manufacturer's information:

Name of manufacturer: TBD

Model number: _____

Serial number: _____

4. Data acquisition system to be used (data logger, strip chart, etc.):

Name of manufacturer: TBD

Model number: _____

Serial number: _____

5. Indicate emission source to be monitored and the location of the specific CEM:

Unit 8

Monitor to be located in the CEMS building, probe to be located in the stack.

6. **Briefly describe the calibration and operational procedures to be used in operating the CEM: (indicate estimate of time lost in calibrating, maintaining, repairing, etc.)**

The computer system will provide automated daily zero/span checks. No lost time to occur due to the daily zero/span checks. We expect between 2-5% lost time due to repairs and maintenance.

7. **Indicate CEM calibration/maintenance schedule:** Calibration/maintenance schedules performed will be described in the Quality Assurance Plan. This will provide for daily, weekly, quarterly, and annual maintenance. CEMS audits will be conducted semi-annually or annually. Other maintenance repairs will be performed as necessary.

8. **Check which program(s) apply to the unit with the monitor:**

☑ NSPS ☑ SIP ☑ PSD ☐ BIF

☐ NESHAPS ☑ Acid Rain ☐ RCRA ☑ Enhanced Monitoring

9. **Monitor span: From:** _____ **To:** _____

10. **Performance protocol (from Appendix B in 40 CFR Part 60):** Performance Specification 3

11. **Insitu/dilution extractive/extractive? (type):** Dilution Extractive

12. **If dilution extractive, give approximate dilution rate:** _____

13. **Conditioning system?** ☑ yes ☐ no

If yes, what type? Dilution Air Conditioning System

14. **Does Appendix F in 40 CFR Part 60 apply?** ☑ yes ☐ no

Name of person preparing application: Nikia Howard

Signature: Nikia Howard **Date:** 2/18/2020

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
PERMIT APPLICATION FOR
STATIONARY INTERNAL COMBUSTION ENGINES

___ — ____ — ____

Permit Number (ADEM Use Only)

1. Facility Name: Alabama Power Company - Barry Steam Electric Generating Plant **Location:** Bucks, Mobile County, Alabama

2. Purpose of Application:

- [x] Initial installation of a new engine (i.e. engine that has never been in service at any location)
- [ ] Initial installation of a used engine (i.e. an engine that has been in service at another location)
- [ ] Modification/Reconstruction of an engine currently installed at the facility
- [ ] Update information for an engine currently installed at the facility
- [ ] Title V Application
- [ ] Other, please describe: _____

If this application is for the installation, modification, or reconstruction of an engine, please provide the date construction is scheduled to begin: First Quarter 2021

If this application is for an engine currently installed at this facility, please provide the date that the engine was initially installed at this facility: _____

3. Engine Identification:

A. Manufacturer's Name: Mitsubishi Hitachi Power Systems Americas Inc. B. Model Number: M501JAC C. Model Year: TBD

D. Facility's Identification Number or Description: Unit 9 Combustion Turbine E. Serial Number: _____

4. Engine Applicability Dates:

A. For a new engine, Date Ordered: _____ B. Date Manufactured: TBD C. Date Modified/Reconstructed: _____

D. For a used engine, approximate date engine was first placed into service at any location: _____

Engine Function: [ ] Compression [x] Electrical Generation (Maximum Electrical Output: 457 MW) [ ] Fire Pump Driver [ ] Other Pump Driver [ ] Research & Development [ ] Test Cell/Stand [ ] Other, please describe: _____

6. Engine Operation: [ ] Emergency Only [x] Non-emergency, please provide typical operating schedule in Items A-D below:

[ ] Limited Use (<100 hr/yr) A. Hours Per Day: 24 B. Days Per Week: 7 C. Weeks per Year: 52

D. Peak Season (if any): _____

7. Engine Specifications:

A. Maximum Brake Horsepower (bhp): _____ B. Maximum Engine Power (kW_m): _____ C. Maximum Heat Input (MMBtu/hr): 3,987

D. Type: [ ] Simple Cycle Turbine [x] Combined Cycle Turbine [ ] Regenerative Cycle Turbine [ ] Reciprocating Engine

E. Piston Movement: [ ] 2-Stroke RICE [ ] 4-Stroke RICE [x] N/A [ ] Other: _____

F. Air/Fuel Mix: [ ] Rich Burn RICE [ ] Lean Burn RICE [ ] Diffusion Flame Turbine [x] Lean Premix Turbine [ ] Other: _____

G. Ignition Type: [ ] Spark [ ] Compression [x] N/A H. Cylinder Displacement (Liters per cylinder): _____

8. Fuel Information:

	Fuel Type/Description	Sulfur Content (indicate % by weight OR ppm)	Fuel-bound Nitrogen Content (indicate % by weight OR ppm)	Percent (%) of Gross Heat Input on Annual Basis
Primary Fuel	Natural Gas	0.6 gr/100 scf		100
Secondary/Backup				

9. Stack Parameters (if a control device is installed, the information should be for the control device's stack exit):

A. Height above grade (feet): 180 B. Inside Diameter at Exit (feet): 23.0 C. Exhaust Gas Volume (ACFM): 1,724,815

D. Base Elevation (feet): ~25 E. Exhaust Gas Temperature°F): 179 F. Are sampling ports available? (•) Yes ( ) No

G. UTM Coordinate (E-W) (km): 402.623 H. UTM Coordinate (N-S) (km): 3,429.631

10. Point Source Emissions (You must attach calculations and, if used as the basis for emission estimates, manufacturer specification sheets):

Pollutant	Uncontrolled[1] Potential Emission Rate		Controlled[1,2] Potential Emission Rate		Basis for Potential Emissions Calculation/Estimate (e.g. AP-42, Manufacturer Data)	Comment (Optional)
	lb/hr	ton/yr	lb/hr	ton/yr		
NOx						See Emissions Calculations in Appendix D.
CO						See Emissions Calculations in Appendix D.
VOC						See Emissions Calculations in Appendix D.
PM						See Emissions Calculations in Appendix D.
SO_2						See Emissions Calculations in Appendix D.
Formaldehyde						See Emission Calculations in Appendix D
Total HAP						See Emission Calculations in Appendix D

[1]Potential emissions should be calculated based on 8,760 hr/yr and maximum operation unless an enforceable limit will be applicable.

[2]If the pollutant is uncontrolled, leave blank.

11. Applicable Regulations (Mark all that apply):

- ☐ 40 CFR 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines
- ☐ 40 CFR 60, Subpart GG, NSPS for Stationary Gas Turbines
- ☒ 40 CFR 60, Subpart KKKK, NSPS for Stationary Combustion Turbines
- ☐ Other: _____
- ☐ 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE
- ☐ 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition ICE
- ☐ 40 CFR 60, Subpart JJJJ, NSPS for Stationary Spark Ignition ICE
- ☐ Other: _____

12. Regulatory Standards, Limitations, and Requirements:

A.

Pollutant/Parameter	Rate/Value	Units of Standard	Regulatory Basis[3]	Engine Potential Emission Rate (in units of standard)
Example: NOx + NMHC	*6.4*	*g/kW-hr*	*NSPS, Subpart IIII*	*4.95 g/kW-hr*
Example: Annual Operation	*6,000*	*hr/yr*	*SMS-PSD*	*NA*
NOx	4	ppmvd @15% O2	ADEMAdmin.Code335-3-8.06(3)	See Calculations in Appendix D
NOx	15	ppmvd @15% O2	40 CFR Part 60, Subpart KKKK	See Calculations in Appendix D
SO2	0.060	lb/MMBtu	40 CFR Part 60, Subpart KKKK	See Calculations in Appendix D

[3]For federal regulations, specify which NSPS or NESHAP is the basis. If a synthetic minor limit is being requested or is already applicable, specify either SMS-PSD or SMS-Title V

B. For engines subject to emission standards under NSPS, Subpart IIII or NSPS, Subpart JJJJ, is this engine certified by the manufacturer pursuant to the applicable regulation to meet the applicable emission standards ? ◉ N/A ○ No ○ Yes (If yes, attach a copy of the certification)

C. For emergency or limited use engines, is this engine equipped with a non-resettable hour meter? ◉ N/A ○ No ○ Yes

13. Pollution Control Information:

A. Device/Technology Type(s):

- [ ] No Controls
- [ ] Air-to-Fuel Ratio Controller
- [ ] Water or Steam Injection
- [x] Low NO_X Burners
- [x] Oxidation Catalyst
- [ ] Selective Non-catalytic Reduction (SNCR)
- [ ] Non-selective Catalytic Reduction (NSCR/3-way Catalyst)
- [x] Selective Catalytic Reduction (SCR)
- [ ] Other: _____
- [ ] Other: _____
- [ ] Other: _____

B. Control Efficiencies (Typical Operation)

Pollutant	% Reduction
NOx	
CO	
VOC	
Formaldehyde	

C. Operational Parameters (if any):

14. Compliance Status:

Is this engine in compliance with all applicable air pollution rules and regulations? (•) Yes ( ) No (If "No", must attach ADEM Form 437)

15. Clarifying/Supplemental Information (Optional):

For additional information, see Technical Support Document.

Please provide the following for the person preparing this application:

Name (Print or Type): Nikia Howard Company/Affiliation: _____

Signature: Nikia Howard Date: 2/18/2020

PERMIT APPLICATION
FOR
INDIRECT HEATING EQUIPMENT
(FUEL BURNING EQUIPMENT)

[ ][ ][ ] - [ ][ ][ ][ ] - [ ][ ][ ][ ]
Do not write in this space

1. **Name of firm or organization:** Alabama Power Company - Barry Steam Electric Generating Plant

2. **Unit Description (i.e. No. 1 Power Boiler):** Unit 9 Duct Burner

Equipment manufacturer's information

Name of manufacturer: TBD

Model number: _____

Rated capacity-input: 917 million (Btu/hr.)

Boiler type: ☐ Fire tube ☐ Water tube ☐ other(specify): _____

Manufactured date: _____

Proposed installation date: _____

Original installation date (if existing): _____

Reconstruction or Modification date (if applicable): _____

3. **Type of fuel used:**

Primary:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas	1020	Btu/ft^3	0.6 gr/100 scf			
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

Standby:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas		Btu/ft^3				
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

4. Purpose (if multipurpose, note percent in each use category):

☐Space heat _____ % ☑Power generation 100 % ☐Process heat _____ %

Other (specify): _____

5. Normal schedule of operation:

Hours per day: 24 Days per week: 7 Weeks per year: 52

6. For each regulated pollutant, describe any limitations on source operation which affects emissions or any work practice standard (attach additional page if necessary):

N/A

7. Fugitive Emissions (attach calculation worksheets):

POLLUTANT	POTENTIAL EMISSIONS lb/hr	POTENTIAL EMISSIONS t/yr	BASIS OF CALCULATION	REGULATORY EMISSION LIMIT (lb/hr)	REGULATORY EMISSION LIMIT (in units of standard)
Particulate					
Sulfur dioxide					
Nitrogen oxides					
Carbon monoxide					
VOC's					
Other					

8. Is there any emission control equipment on this emission source?

☑Yes ☐No (If "yes", complete ADEM Form 110)

9. Point Emissions (attach calculation worksheets):

POLLUTANT	POTENTIAL EMISSIONS lb/hr	POTENTIAL EMISSIONS t/yr	BASIS OF CALCULATION	REGULATORY EMISSION LIMIT (lb/hr)	REGULATORY EMISSION LIMIT (in units of standard)
Particulate				See, Emissions Calculations	in Appendix D.
Sulfur dioxide				See, Emissions Calculations	in Appendix D.
Nitrogen oxides				See, Emissions Calculations	in Appendix D.
Carbon monoxide				See, Emissions Calculations	in Appendix D.
VOC's				See, Emissions Calculations	in Appendix D.
Other					

10. Stack data:

UTM Coordinate (E-W) 402.623 (km) UTM Coordinate (N-S) 3,429.631 (km)

Height above grade 180 (feet) Gas temperature at exit 179 (°F)

Inside diameter at exit 23.0 (feet) Volume of gas discharged 1,724,815 (ACFM)

Base Elevation ~25 (feet)

Are sampling ports available? ◉ Yes ○ No (If "yes", describe. Draw on separate sheet if necessary):

11. Is this item in compliance with all applicable air pollution rules and regulations?

◉ Yes ○ No (if "no", a compliance schedule, ADEM Form 437, must be attached.)

Name of person preparing application: Nikia Howard

Signature: Nikia Howard Date: 2/18/2020

ADEM

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

PERMIT APPLICATION

FOR

AIR POLLUTION CONTROL DEVICE

☐☐☐ - ☐☐☐☐ - ☐☐☐☐
(ADEM Use Only)

1. **Name of firm or organization** Alabama Power Company - Barry Steam Electric Generating Plant

2. **Type of pollution control device: (if more than one, check each; however, separate forms are to be submitted for each specific device.)**

   ☐ Settling chamber ☐ Electrostatic precipitator
   ☐ Afterburner ☐ Baghouse
   ☐ Cyclone ☐ Multiclone
   ☐ Absorber ☐ Adsorber
   ☐ Condenser ☐ Wet Suppression

   Wet scrubber (kind): _____

   Stage 1 - Vapor balance (type): _____

   Other (describe): Selective Catalytic Reduction (SCR)

3. **Control device manufacturer's information:**

   Name of manufacturer TBD Model No. _____

4. **Emission source to which device is installed or is to be installed:**

   Unit 9

5. **Emission parameters:**

	Pollutants Removed		
	Pollutant #1	Pollutant #2	Pollutant #3
	NOx		
Mass emission rate (#/hr)			
Uncontrolled	See Emissions Calculations	in Appendix D.	
Designed			
Manufacturer's guaranteed			
Mass emission rate (Expressed as units of standard)			
Required by regulation			
Manufacturer's guaranteed			
Removal efficiency (%)			
Designed			
Manufacturer's guaranteed			

6. Gas conditions:

	Inlet	Intermediate Locations	Outlet
Volume (SDCFM, 68°f, 29.92" hg)			
(ACFM, existing conditions)			1,724,815
Temperature (°F)			179
Velocity (ft/sec)			69.19
Percent moisture			9.70

Pressure drop across device: _____ (inches H_20)

7. Stack dimensions:

UTM Coordinates (E-W)..... 402.623 (km)

UTM Coordinates (N-S)..... 3,429.631 (km)

Height above grade ..... 180 (feet)

Inside diameter at exit (if opening is round)..... 23 (feet)

Inside area at exit (if opening is not round) ..... _____ (sq. feet)

Base Elevation..... ~25 (feet)

GEP Stack Height ..... 213 (feet)

8. Provide a flow diagram which includes gas exit from process, each control device, location of by-pass, fan or blower, each emission point, exits for collected pollutants, and location of sampling ports.

See Attached.

9. Enclosed are:

☐ Blueprints ☐ Particle size distribution report

☐ Manufacturer's literature ☐ Size-efficiency curves

☐ Emissions test of existing installation ☐ Fan curves

☒ Other Enclosed emissions calculations provide further details.

10. If the pollution control device is of unusual design, please provide a sketch of the device.

11. List below the important operating parameters for the device. (For example: air/cloth ratio and fabric type, weight, and weave for baghouse; throat velocity and water use rate for a venturi scrubber; etc.)

Ammonia injection is controlled to maintain the desired NOx emission rate.

12. By-pass (if any) is to be used when:

N/A

13. Disposal of collected air pollutants:

	Solid waste	Solid waste	Liquid waste	Liquid waste
Volume				
Composition				
Is waste hazardous?				
Method of disposal				
Final destination				

If collected air pollutants are recycled, describe:

Name of person preparing application Nikia Howard

Signature Nikia Howard Date 2/18/2020

ADEM

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

PERMIT APPLICATION

FOR

AIR POLLUTION CONTROL DEVICE

___ - ____ - ____
(ADEM Use Only)

1. **Name of firm or organization** Alabama Power Company - Barry Steam Electric Generating Plant

2. **Type of pollution control device: (if more than one, check each; however, separate forms are to be submitted for each specific device.)**

   ☐ Settling chamber ☐ Electrostatic precipitator
   ☐ Afterburner ☐ Baghouse
   ☐ Cyclone ☐ Multiclone
   ☐ Absorber ☐ Adsorber
   ☐ Condenser ☐ Wet Suppression

   Wet scrubber (kind): _____

   Stage 1 - Vapor balance (type): _____

   Other (describe): Oxidation Catalyst System

3. **Control device manufacturer's information:**

   Name of manufacturer TBD Model No. _____

4. **Emission source to which device is installed or is to be installed:**

   Unit 9

5. **Emission parameters:**

	Pollutants Removed		
	Pollutant #1	Pollutant #2	Pollutant #3
	CO	VOC	
Mass emission rate (#/hr)			
Uncontrolled	See Emissions Calculations	in Appendix D.	
Designed			
Manufacturer's guaranteed			
Mass emission rate (Expressed as units of standard)			
Required by regulation			
Manufacturer's guaranteed			
Removal efficiency (%)			
Designed			
Manufacturer's guaranteed			

6. Gas conditions:

	Inlet	Intermediate Locations	Outlet
Volume (SDCFM, 68°f, 29.92" hg)			
(ACFM, existing conditions)			1,724,815
Temperature (°F)			179
Velocity (ft/sec)			69.19
Percent moisture			9.70

Pressure drop across device: _____ (inches H_20)

7. Stack dimensions:

UTM Coordinates (E-W)..... 402.623 (km)

UTM Coordinates (N-S)..... 3,429.631 (km)

Height above grade ..... 180 (feet)

Inside diameter at exit (if opening is round)..... 23 (feet)

Inside area at exit (if opening is not round) ..... _____ (sq. feet)

Base Elevation..... ~25 (feet)

GEP Stack Height ..... 213 (feet)

8. Provide a flow diagram which includes gas exit from process, each control device, location of by-pass, fan or blower, each emission point, exits for collected pollutants, and location of sampling ports.

See Attached.

9. Enclosed are:

☐ Blueprints ☐ Particle size distribution report

☐ Manufacturer's literature ☐ Size-efficiency curves

☐ Emissions test of existing installation ☐ Fan curves

☒ Other Enclosed emissions calculations provide further details.

10. If the pollution control device is of unusual design, please provide a sketch of the device.

11. List below the important operating parameters for the device. (For example: air/cloth ratio and fabric type, weight, and weave for baghouse; throat velocity and water use rate for a venturi scrubber; etc.)

12. By-pass (if any) is to be used when:

N/A

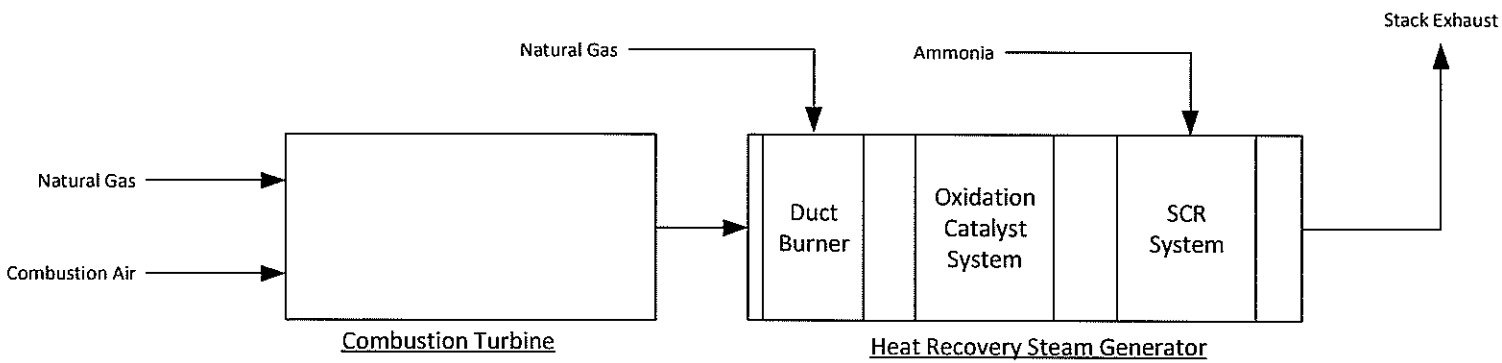
13. Disposal of collected air pollutants:

	Solid waste	Solid waste	Liquid waste	Liquid waste
Volume				
Composition				
Is waste hazardous?				
Method of disposal				
Final destination				

If collected air pollutants are recycled, describe:

Name of person preparing application Nikia Howard

Signature Nikia Howard Date 2/18/2020



COMBUSTION TURBINE/HRSG FLOW DIAGRAM

PERMIT APPLICATION
FOR
CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

[ ][ ][ ] - [ ][ ][ ][ ] - [ ][ ][ ][ ]
Do not write in this space

1. **Name of firm or organization:** Alabama Power Company - Barry Steam Electric Generating Plant

2. **List pollutant or parameter the continuous emission monitoring system is measuring:**

- ☐ Sulfur dioxide
- ☑ Nitrogen oxides
- ☐ PM10
- ☐ Oxygen
- ☐ Pressure
- ☐ Carbon dioxide
- ☐ Carbon monoxide
- ☐ Particulates
- ☐ Exhaust temperature
- ☐ Hydrogen chloride
- ☐ Opacity
- ☐ Temperature
  - ☐ Exhaust gas
  - ☐ Primary Chamber
  - ☐ Secondary chamber
- ☐ Total reduced sulfides
- ☐ Hydrogen sulfide
- ☐ Flow rate
- ☐ VOCs
- ☐ Other (explain): _____

3. **CEMS Manufacturer's information:**

Name of manufacturer: TBD

Model number: _____

Serial number: _____

4. **Data acquisition system to be used (data logger, strip chart, etc.):**

Name of manufacturer: TBD

Model number: _____

Serial number: _____

5. **Indicate emission source to be monitored and the location of the specific CEM:**

Unit 9

Monitor to be located in the CEMS building, probe to be located in the stack.

6. **Briefly describe the calibration and operational procedures to be used in operating the CEM: (indicate estimate of time lost in calibrating, maintaining, repairing, etc.)**

The computer system will provide automated daily zero/span checks. No lost time to occur due to the daily zero/span checks. We expect between 2-5% lost time due to repairs and maintenance.

7. **Indicate CEM calibration/maintenance schedule:** Calibration/maintenance schedules performed will be described in the Quality Assurance Plan. This will provide for daily, weekly, quarterly, and annual maintenance. CEMS audits will be conducted semi-annually or annually. Other maintenance repairs will be performed as necessary.

8. **Check which program(s) apply to the unit with the monitor:**

☑ NSPS ☑ SIP ☑ PSD ☐ BIF

☐ NESHAPS ☑ Acid Rain ☐ RCRA ☑ Enhanced Monitoring

9. **Monitor span: From:** _____ **To:** _____

10. **Performance protocol (from Appendix B in 40 CFR Part 60):** Performance Specification 2

11. **Insitu/dilution extractive/extractive? (type):** Dilution Extractive

12. **If dilution extractive, give approximate dilution rate:** _____

13. **Conditioning system?** ☑ yes ☐ no

If yes, what type? Dilution Air Conditioning System

14. **Does Appendix F in 40 CFR Part 60 apply?** ☑ yes ☐ no

Name of person preparing application: Nikia Howard

Signature: Nikia Howard **Date:** 2/18/2020

PERMIT APPLICATION
FOR
CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

[ ][ ][ ] - [ ][ ][ ][ ] - [ ][ ][ ][ ]
Do not write in this space

1. Name of firm or organization: Alabama Power Company - Barry Steam Electric Generating Plant

2. List pollutant or parameter the continuous emission monitoring system is measuring:

- ☐ Sulfur dioxide
- ☐ Nitrogen oxides
- ☐ PM10
- ☐ Oxygen
- ☐ Pressure
- ☑ Carbon dioxide
- ☐ Carbon monoxide
- ☐ Particulates
- ☐ Exhaust temperature
- ☐ Hydrogen chloride
- ☐ Opacity
- ☐ Temperature
  - ☐ Exhaust gas
  - ☐ Primary Chamber
  - ☐ Secondary chamber
- ☐ Total reduced sulfides
- ☐ Hydrogen sulfide
- ☐ Flow rate
- ☐ VOCs
- ☐ Other (explain): _____

3. CEMS Manufacturer's information:

Name of manufacturer: TBD

Model number: _____

Serial number: _____

4. Data acquisition system to be used (data logger, strip chart, etc.):

Name of manufacturer: TBD

Model number: _____

Serial number: _____

5. Indicate emission source to be monitored and the location of the specific CEM:

Unit 9

Monitor to be located in the CEMS building, probe to be located in the stack.

6. **Briefly describe the calibration and operational procedures to be used in operating the CEM: (indicate estimate of time lost in calibrating, maintaining, repairing, etc.)**

The computer system will provide automated daily zero/span checks. No lost time to occur due to the daily zero/span checks. We expect between 2-5% lost time due to repairs and maintenance.

7. **Indicate CEM calibration/maintenance schedule:** Calibration/maintenance schedules performed will be described in the Quality Assurance Plan. This will provide for daily, weekly, quarterly, and annual maintenance. CEMS audits will be conducted semi-annually or annually. Other maintenance repairs will be performed as necessary.

8. **Check which program(s) apply to the unit with the monitor:**

☑ NSPS ☑ SIP ☑ PSD ☐ BIF

☐ NESHAPS ☑ Acid Rain ☐ RCRA ☑ Enhanced Monitoring

9. **Monitor span: From:** _____ **To:** _____

10. **Performance protocol (from Appendix B in 40 CFR Part 60):** Performance Specification 3

11. **Insitu/dilution extractive/extractive? (type):** Dilution Extractive

12. **If dilution extractive, give approximate dilution rate:** _____

13. **Conditioning system?** ☑ yes ☐ no

If yes, what type? Dilution Air Conditioning System

14. **Does Appendix F in 40 CFR Part 60 apply?** ☑ yes ☐ no

Name of person preparing application: Nikia Howard

Signature: Nikia Howard **Date:** 2/18/2020

PERMIT APPLICATION
FOR
INDIRECT HEATING EQUIPMENT
(FUEL BURNING EQUIPMENT)

[ ][ ][ ] - [ ][ ][ ][ ] - [ ][ ][ ][ ]
Do not write in this space

1. **Name of firm or organization:** Alabama Power Company - Barry Steam Electric Generating Plant

2. **Unit Description (i.e. No. 1 Power Boiler):** Auxiliary Boiler

Equipment manufacturer's information

Name of manufacturer: TBD

Model number: _____

Rated capacity-input: 90.5 million (Btu/hr.)

Boiler type: ☐ Fire tube ☑ Water tube ☐ other(specify): _____

Manufactured date: _____

Proposed installation date: _____

Original installation date (if existing): _____

Reconstruction or Modification date (if applicable): _____

3. **Type of fuel used:**

Primary:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas	1020	Btu/ft^3	0.6 gr/100 scf			
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

Standby:

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas		Btu/ft^3				
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

4. Purpose (if multipurpose, note percent in each use category):

☐Space heat _____ % ☐Power generation _____ % ☑Process heat 100 %

Other (specify): _____

5. Normal schedule of operation:

Hours per day: 24 _____ Days per week: 7 _____ Weeks per year: 52 _____

6. For each regulated pollutant, describe any limitations on source operation which affects emissions or any work practice standard (attach additional page if necessary):

_____

_____

7. Fugitive Emissions (attach calculation worksheets):

POLLUTANT	POTENTIAL EMISSIONS lb/hr	POTENTIAL EMISSIONS t/yr	BASIS OF CALCULATION	REGULATORY EMISSION LIMIT (lb/hr)	REGULATORY EMISSION LIMIT (in units of standard)
Particulate					
Sulfur dioxide					
Nitrogen oxides					
Carbon monoxide					
VOC's					
Other					

8. Is there any emission control equipment on this emission source?

☐Yes ☑No (If "yes", complete ADEM Form 110)

9. Point Emissions (attach calculation worksheets):

POLLUTANT	POTENTIAL EMISSIONS lb/hr	POTENTIAL EMISSIONS t/yr	BASIS OF CALCULATION	REGULATORY EMISSION LIMIT (lb/hr)	REGULATORY EMISSION LIMIT (in units of standard)
Particulate				See Emissions Calculations	in Appendix D.
Sulfur dioxide				See Emissions Calculations	in Appendix D.
Nitrogen oxides				See Emissions Calculations	in Appendix D.
Carbon monoxide				See Emissions Calculations	in Appendix D.
VOC's				See Emissions Calculations	in Appendix D.
Other					

10. Stack data:

UTM Coordinate (E-W) 402488.69 (km) UTM Coordinate (N-S) 3429770.04 (km)

Height above grade 70 (feet) Gas temperature at exit 309 (°F)

Inside diameter at exit 3.5 (feet) Volume of gas discharged 37,522 (ACFM)

Base Elevation ~25 (feet)

Are sampling ports available? ◉ Yes ○ No (If "yes", describe. Draw on separate sheet if necessary):

11. Is this item in compliance with all applicable air pollution rules and regulations?

◉ Yes ○ No (if "no", a compliance schedule, ADEM Form 437, must be attached.)

Name of person preparing application: Nikia Howard

Signature: Nikia Howard Date: 2/18/2020

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
PERMIT APPLICATION FOR
STATIONARY INTERNAL COMBUSTION ENGINES

___ — ____ — ____

Permit Number (ADEM Use Only)

1. Facility Name: Alabama Power Company - Barry Steam Electric Generating Plant **Location:** Bucks, Mobile County, Alabama

2. Purpose of Application:

- [x] Initial installation of a new engine (i.e. engine that has never been in service at any location)
- [ ] Initial installation of a used engine (i.e. an engine that has been in service at another location)
- [ ] Modification/Reconstruction of an engine currently installed at the facility
- [ ] Update information for an engine currently installed at the facility
- [ ] Title V Application
- [ ] Other, please describe: _____

If this application is for the installation, modification, or reconstruction of an engine, please provide the date construction is scheduled to begin: First Quarter 2021

If this application is for an engine currently installed at this facility, please provide the date that the engine was initially installed at this facility: _____

3. Engine Identification:

A. Manufacturer's Name: TBD B. Model Number: _____ C. Model Year: TBD

D. Facility's Identification Number or Description: Unit 8 Emergency Generator E. Serial Number: _____

4. Engine Applicability Dates:

A. For a new engine, Date Ordered: _____ B. Date Manufactured: TBD C. Date Modified/Reconstructed: _____

D. For a used engine, approximate date engine was first placed into service at any location: _____

Engine Function: [ ] Compression [ ] Electrical Generation (Maximum Electrical Output: _____) [ ] Fire Pump Driver [ ] Other Pump Driver [ ] Research & Development [ ] Test Cell/Stand [x] Other, please describe: back-up power

6. Engine Operation: [x] Emergency Only [ ] Non-emergency, please provide typical operating schedule in Items A-D below:

[ ] Limited Use (<100 hr/yr) A. Hours Per Day: _____ B. Days Per Week: _____ C. Weeks per Year: _____

D. Peak Season (if any): _____

7. Engine Specifications:

A. Maximum Brake Horsepower (bhp): 2010.7 B. Maximum Engine Power (kW_m): 1,500 C. Maximum Heat Input (MMBtu/hr): 17.471

D. Type: [ ] Simple Cycle Turbine [ ] Combined Cycle Turbine [ ] Regenerative Cycle Turbine [x] Reciprocating Engine

E. Piston Movement: [ ] 2-Stroke RICE [x] 4-Stroke RICE [ ] N/A [ ] Other: _____

F. Air/Fuel Mix: [ ] Rich Burn RICE [x] Lean Burn RICE [ ] Diffusion Flame Turbine [ ] Lean Premix Turbine [ ] Other: _____

G. Ignition Type: [ ] Spark [x] Compression [ ] N/A H. Cylinder Displacement (Liters per cylinder): _____

8. Fuel Information:

	Fuel Type/Description	Sulfur Content (indicate % by weight OR ppm)	Fuel-bound Nitrogen Content (indicate % by weight OR ppm)	Percent (%) of Gross Heat Input on Annual Basis
Primary Fuel	Diesel	0.0015%		100
Secondary/Backup				

9. Stack Parameters (if a control device is installed, the information should be for the control device's stack exit):

A. Height above grade (feet): 17.75 B. Inside Diameter at Exit (feet): 1.0 C. Exhaust Gas Volume (ACFM): 4,524

D. Base Elevation (feet): ~25 E. Exhaust Gas Temperature°F): 800 F. Are sampling ports available? (•) Yes ( ) No

G. UTM Coordinate (E-W) (km): 402.537 H. UTM Coordinate (N-S) (km): 3,429.706

10. Point Source Emissions (You must attach calculations and, if used as the basis for emission estimates, manufacturer specification sheets):

Pollutant	Uncontrolled[1] Potential Emission Rate		Controlled[1,2] Potential Emission Rate		Basis for Potential Emissions Calculation/Estimate (e.g. AP-42, Manufacturer Data)	Comment (Optional)
	lb/hr	ton/yr	lb/hr	ton/yr		
NOx						See Emissions Calculations in Appendix D.
CO						See Emissions Calculations in Appendix D.
VOC						See Emissions Calculations in Appendix D.
PM						See Emissions Calculations in Appendix D.
SO_2						See Emissions Calculations in Appendix D.
Formaldehyde						See Emission Calculations in Appendix D
Total HAP						See Emission Calculations in Appendix D

[1]Potential emissions should be calculated based on 8,760 hr/yr and maximum operation unless an enforceable limit will be applicable.

[2]If the pollutant is uncontrolled, leave blank.

11. Applicable Regulations (Mark all that apply):

- ☐ 40 CFR 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines
- ☐ 40 CFR 60, Subpart GG, NSPS for Stationary Gas Turbines
- ☐ 40 CFR 60, Subpart KKKK, NSPS for Stationary Combustion Turbines
- ☐ Other: _____
- ☒ 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE
- ☒ 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition ICE
- ☐ 40 CFR 60, Subpart JJJJ, NSPS for Stationary Spark Ignition ICE
- ☐ Other: _____

12. Regulatory Standards, Limitations, and Requirements:

A.

Pollutant/Parameter	Rate/Value	Units of Standard	Regulatory Basis[3]	Engine Potential Emission Rate (in units of standard)
Example: NOx + NMHC	*6.4*	*g/kW-hr*	*NSPS, Subpart IIII*	*4.95 g/kW-hr*
Example: Annual Operation	*6,000*	*hr/yr*	*SMS-PSD*	*NA*
See, Technical Support Document.				

[3]For federal regulations, specify which NSPS or NESHAP is the basis. If a synthetic minor limit is being requested or is already applicable, specify either SMS-PSD or SMS-Title V

B. For engines subject to emission standards under NSPS, Subpart IIII or NSPS, Subpart JJJJ, is this engine certified by the manufacturer pursuant to the applicable regulation to meet the applicable emission standards ? ○ N/A ○ No ◉ Yes (If yes, attach a copy of the certification)

C. For emergency or limited use engines, is this engine equipped with a non-resettable hour meter? ○ N/A ○ No ◉ Yes

13. Pollution Control Information:

A. Device/Technology Type(s):

- [x] No Controls
- [ ] Air-to-Fuel Ratio Controller
- [ ] Water or Steam Injection
- [ ] Low NO_X Burners
- [ ] Oxidation Catalyst
- [ ] Selective Non-catalytic Reduction (SNCR)
- [ ] Non-selective Catalytic Reduction (NSCR/3-way Catalyst)
- [ ] Selective Catalytic Reduction (SCR)
- [ ] Other: _____
- [ ] Other: _____
- [ ] Other: _____

B. Control Efficiencies (Typical Operation)

Pollutant	% Reduction
NOx	
CO	
VOC	
Formaldehyde	

C. Operational Parameters (if any):

14. Compliance Status:

Is this engine in compliance with all applicable air pollution rules and regulations? (●) Yes ( ) No (If "No", must attach ADEM Form 437)

15. Clarifying/Supplemental Information (Optional):

For additional information, see Technical Support Document.

Please provide the following for the person preparing this application:

Name (Print or Type): Nikia Howard Company/Affiliation: _____

Signature: Nikia Howard Date: 2/18/2020

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
PERMIT APPLICATION FOR
STATIONARY INTERNAL COMBUSTION ENGINES

___ — ____ — ____

Permit Number (ADEM Use Only)

1. Facility Name: Alabama Power Company - Barry Steam Electric Generating Plant **Location:** Bucks, Mobile County, Alabama

2. Purpose of Application:

- [x] Initial installation of a new engine (i.e. engine that has never been in service at any location)
- [ ] Initial installation of a used engine (i.e. an engine that has been in service at another location)
- [ ] Modification/Reconstruction of an engine currently installed at the facility
- [ ] Update information for an engine currently installed at the facility
- [ ] Title V Application
- [ ] Other, please describe: _____

If this application is for the installation, modification, or reconstruction of an engine, please provide the date construction is scheduled to begin: First Quarter 2021

If this application is for an engine currently installed at this facility, please provide the date that the engine was initially installed at this facility: _____

3. Engine Identification:

A. Manufacturer's Name: TBD B. Model Number: _____ C. Model Year: TBD

D. Facility's Identification Number or Description: Unit 9 Emergency Generator E. Serial Number: _____

4. Engine Applicability Dates:

A. For a new engine, Date Ordered: _____ B. Date Manufactured: TBD C. Date Modified/Reconstructed: _____

D. For a used engine, approximate date engine was first placed into service at any location: _____

Engine Function: [ ] Compression [ ] Electrical Generation (Maximum Electrical Output: _____) [ ] Fire Pump Driver [ ] Other Pump Driver [ ] Research & Development [ ] Test Cell/Stand [x] Other, please describe: back-up power

6. Engine Operation: [x] Emergency Only [ ] Non-emergency, please provide typical operating schedule in Items A-D below:

[ ] Limited Use (<100 hr/yr) A. Hours Per Day: _____ B. Days Per Week: _____ C. Weeks per Year: _____

D. Peak Season (if any): _____

7. Engine Specifications:

A. Maximum Brake Horsepower (bhp): 2010.7 B. Maximum Engine Power (kW_m): 1,500 C. Maximum Heat Input (MMBtu/hr): 17.471

D. Type: [ ] Simple Cycle Turbine [ ] Combined Cycle Turbine [ ] Regenerative Cycle Turbine [x] Reciprocating Engine

E. Piston Movement: [ ] 2-Stroke RICE [x] 4-Stroke RICE [ ] N/A [ ] Other: _____

F. Air/Fuel Mix: [ ] Rich Burn RICE [x] Lean Burn RICE [ ] Diffusion Flame Turbine [ ] Lean Premix Turbine [ ] Other: _____

G. Ignition Type: [ ] Spark [x] Compression [ ] N/A H. Cylinder Displacement (Liters per cylinder): _____

8. Fuel Information:

	Fuel Type/Description	Sulfur Content (indicate % by weight OR ppm)	Fuel-bound Nitrogen Content (indicate % by weight OR ppm)	Percent (%) of Gross Heat Input on Annual Basis
Primary Fuel	Diesel	0.0015%		100
Secondary/Backup				

9. Stack Parameters (if a control device is installed, the information should be for the control device's stack exit):

A. Height above grade (feet): 17.75 B. Inside Diameter at Exit (feet): 1.0 C. Exhaust Gas Volume (ACFM): 4,524

D. Base Elevation (feet): ~25 E. Exhaust Gas Temperature°F): 800 F. Are sampling ports available? (•) Yes ( ) No

G. UTM Coordinate (E-W) (km): 402.663 H. UTM Coordinate (N-S) (km): 3,429.578

10. Point Source Emissions (You must attach calculations and, if used as the basis for emission estimates, manufacturer specification sheets):

Pollutant	Uncontrolled[1] Potential Emission Rate		Controlled[1,2] Potential Emission Rate		Basis for Potential Emissions Calculation/Estimate (e.g. AP-42, Manufacturer Data)	Comment (Optional)
	lb/hr	ton/yr	lb/hr	ton/yr		
NOx						See Emissions Calculations in Appendix D.
CO						See Emissions Calculations in Appendix D.
VOC						See Emissions Calculations in Appendix D.
PM						See Emissions Calculations in Appendix D.
SO_2						See Emissions Calculations in Appendix D.
Formaldehyde						See Emission Calculations in Appendix D
Total HAP						See Emission Calculations in Appendix D

[1]Potential emissions should be calculated based on 8,760 hr/yr and maximum operation unless an enforceable limit will be applicable.

[2]If the pollutant is uncontrolled, leave blank.

11. Applicable Regulations (Mark all that apply):

- ☐ 40 CFR 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines
- ☐ 40 CFR 60, Subpart GG, NSPS for Stationary Gas Turbines
- ☐ 40 CFR 60, Subpart KKKK, NSPS for Stationary Combustion Turbines
- ☐ Other: _____
- ☒ 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE
- ☒ 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition ICE
- ☐ 40 CFR 60, Subpart JJJJ, NSPS for Stationary Spark Ignition ICE
- ☐ Other: _____

12. Regulatory Standards, Limitations, and Requirements:

A.

Pollutant/Parameter	Rate/Value	Units of Standard	Regulatory Basis[3]	Engine Potential Emission Rate (in units of standard)
Example: NOx + NMHC	*6.4*	*g/kW-hr*	*NSPS, Subpart IIII*	*4.95 g/kW-hr*
Example: Annual Operation	*6,000*	*hr/yr*	*SMS-PSD*	*NA*
See, Technical Support Document.				

[3]For federal regulations, specify which NSPS or NESHAP is the basis. If a synthetic minor limit is being requested or is already applicable, specify either SMS-PSD or SMS-Title V

B. For engines subject to emission standards under NSPS, Subpart IIII or NSPS, Subpart JJJJ, is this engine certified by the manufacturer pursuant to the applicable regulation to meet the applicable emission standards ? ○ N/A ○ No ◉ Yes (If yes, attach a copy of the certification)

C. For emergency or limited use engines, is this engine equipped with a non-resettable hour meter? ○ N/A ○ No ◉ Yes

13. Pollution Control Information:

A. Device/Technology Type(s):

- [x] No Controls
- [ ] Air-to-Fuel Ratio Controller
- [ ] Water or Steam Injection
- [ ] Low NO_X Burners
- [ ] Oxidation Catalyst
- [ ] Selective Non-catalytic Reduction (SNCR)
- [ ] Non-selective Catalytic Reduction (NSCR/3-way Catalyst)
- [ ] Selective Catalytic Reduction (SCR)
- [ ] Other: _____
- [ ] Other: _____
- [ ] Other: _____

B. Control Efficiencies (Typical Operation)

Pollutant	% Reduction
NOx	
CO	
VOC	
Formaldehyde	

C. Operational Parameters (if any):

14. Compliance Status:

Is this engine in compliance with all applicable air pollution rules and regulations? (●) Yes ( ) No (If "No", must attach ADEM Form 437)

15. Clarifying/Supplemental Information (Optional):

For additional information, see Technical Support Document.

Please provide the following for the person preparing this application:

Name (Print or Type): Nikia Howard Company/Affiliation: _____

Signature: Nikia Howard Date: 2/18/2020

PERMIT APPLICATION
FOR
MANUFACTURING OR PROCESSING OPERATION

[ ][ ][ ] - [ ][ ][ ][ ] - [ ][ ][ ][ ]
Do not write in this space

1. **Name of firm or organization:** Alabama Power Company - Barry Steam Electric Generating Plant

2. **Briefly describe the operation of this unit or process in your facility: (separate forms are to be submitted for each type of process or for multiple units of one process type. If the unit or process receives input material from, or provides input material to, another operation, please indicate the relationship between the operations.) An application should be completed for each alternative operating scenario.**

   Operating scenario number 1

3. **Type of unit or process (e.g., calcining kiln, cupola furnace):** Cooling Tower

   Make: TBD **Model:**

   Rated process capacity (manufacturer's or designer's guaranteed maximum) in pounds/hour:

   Manufactured date: **Proposed installation date:** 2021

   Original installation date (if existing):

   Reconstruction or Modification date (if applicable):

4. **Normal operating schedule:**

   Hours per day: 24 **Days per week:** 7 **Weeks per year:** 52

   Peak production season (if any):

5. Materials (feed input) used in unit or process (include solid fuel materials used, if any):

Material	Process Rate Average (lb/hr)	Maximum (lb/hr)	Quantity tons/year
Water Circulation	182,650 gallons per minute	219,180 gallons per minute	

6. Total heat input capacity of process heating equipment (exclude fuel used by indirect heating equipment previously described on ADEM Form 104):_____MMBtu/hr

Fuel	Heat Content	Units	Max. % Sulfur	Max. % Ash	Grade No. [fuel oil only]	Supplier [used oil only]
Coal		Btu/lb				
Fuel Oil		Btu/gal				
Natural Gas		Btu/ft^3				
L. P. Gas		Btu/ft^3				
Wood		Btu/lb				
Other (specify)						

7. Products of process or unit:

Products	Quantity/year	Units of production
N/A		

8. For each regulated pollutant, describe any limitations on source operation which affects emissions or any work practice standard (attach additional page if necessary):

See Technical Support Document.

9. Is there any emission control equipment on this emission source?

☐ Yes ☑ No (Where a control device exists, ADEM Form 110 must be completed and attached).

10. Air contaminant emission points: (Each point of emission should be listed separately and numbered so that it can be located on the attached flow diagram):

Emission Point	Stack							
	UTM Coordinates		Height Above Grade (Feet)	Base Elevation (Feet)	Diameter (Feet)	Gas Exit Velocity (Feet/Sec)	Volume of Gas Discharged (ACFM)	Exit Temperature (°F)
	E-W (km)	N-S (km)						
Unit 8 Cooling Tower	402.593	3,429.754	30	~25	34	40.7	15,536,768	90
Unit 9 Cooling Tower	402.741	3,429.604	30	~25	34	40.7	15,536,768	90

* Std temperature is 68°F - Std pressure is 29.92" in Hg.

11. Air contaminants emitted: Basis of estimate (material balance, stack test, emission factor, etc.) must be clearly indicated on calculations appended to this form. Fugitive emissions must be included and calculations must be appended.

Emission Point	Pollutants	Potential Emissions			Regulatory Emission Limit	
		(lb/hr)	(Tons/yr)	Basis of Calculation	(lb/hr)	(units of standard)
Unit 8 Cooling Tower	See Emissions Calculations in Appendix D.					
Unit 9 Cooling Tower	See Emissions Calculations in Appendix D.					

12. Using a flow diagram:

(1) Illustrate input of raw materials,

(2) Label production processes, process fuel combustion, process equipment and air pollution control equipment,

(3) Illustrate locations of air contaminant release so that emission points under item 10 can be identified.

☐ (Check box if extra pages are attached)
Process flow diagram

13. Is this unit or process in compliance with all applicable air pollution rules and regulations?

☑ Yes ☐ No

(if "no", a compliance schedule, ADEM Form 437 must be completed and attached.)

14. Does the input material or product from this process or unit contain finely divided materials which could become airborne?

☑ Yes ☐ No

15. If "yes", is this material stored in piles or in some other facility as to make possible the creation of fugitive dust problems?

☐ Yes ☑ No

List storage piles or other facility (if any):

Type of material	Particle size (diameter or screen size)	Pile size or facility (average tons)	Methods utilized to control fugitive emissions (wetted, covered, etc.)

Name of person preparing application: Nikia Howard

Signature: Nikia Howard Date: 2/18/2020

ALABAMA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
PERMIT APPLICATION FOR
STATIONARY INTERNAL COMBUSTION ENGINES

___ — ____ — ____

Permit Number (ADEM Use Only)

1. Facility Name: Alabama Power Company - Barry Steam Electric Generating Plant **Location:** Bucks, Mobile County, Alabama

2. Purpose of Application:

- [x] Initial installation of a new engine (i.e. engine that has never been in service at any location)
- [ ] Initial installation of a used engine (i.e. an engine that has been in service at another location)
- [ ] Modification/Reconstruction of an engine currently installed at the facility
- [ ] Update information for an engine currently installed at the facility
- [ ] Title V Application
- [ ] Other, please describe: _____

If this application is for the installation, modification, or reconstruction of an engine, please provide the date construction is scheduled to begin: First Quarter 2021

If this application is for an engine currently installed at this facility, please provide the date that the engine was initially installed at this facility: _____

3. Engine Identification:

A. Manufacturer's Name: TBD B. Model Number: _____ C. Model Year: TBD

D. Facility's Identification Number or Description: Fire Water Pump Engine E. Serial Number: _____

4. Engine Applicability Dates:

A. For a new engine, Date Ordered: _____ B. Date Manufactured: TBD C. Date Modified/Reconstructed: _____

D. For a used engine, approximate date engine was first placed into service at any location: _____

Engine Function: [ ] Compression [ ] Electrical Generation (Maximum Electrical Output: _____) [x] Fire Pump Driver [ ] Other Pump Driver [ ] Research & Development [ ] Test Cell/Stand [ ] Other, please describe: _____

6. Engine Operation: [x] Emergency Only [ ] Non-emergency, please provide typical operating schedule in Items A-D below:

[ ] Limited Use (<100 hr/yr) A. Hours Per Day: _____ B. Days Per Week: _____ C. Weeks per Year: _____

D. Peak Season (if any): _____

7. Engine Specifications:

A. Maximum Brake Horsepower (bhp): 316 B. Maximum Engine Power (kW_m): 236 C. Maximum Heat Input (MMBtu/hr): 2.070

D. Type: [ ] Simple Cycle Turbine [ ] Combined Cycle Turbine [ ] Regenerative Cycle Turbine [x] Reciprocating Engine

E. Piston Movement: [ ] 2-Stroke RICE [x] 4-Stroke RICE [ ] N/A [ ] Other: _____

F. Air/Fuel Mix: [ ] Rich Burn RICE [x] Lean Burn RICE [ ] Diffusion Flame Turbine [ ] Lean Premix Turbine [ ] Other: _____

G. Ignition Type: [ ] Spark [x] Compression [ ] N/A H. Cylinder Displacement (Liters per cylinder): _____

8. Fuel Information:

	Fuel Type/Description	Sulfur Content (indicate % by weight OR ppm)	Fuel-bound Nitrogen Content (indicate % by weight OR ppm)	Percent (%) of Gross Heat Input on Annual Basis
Primary Fuel	Diesel	0.0015%		100
Secondary/Backup				

9. Stack Parameters (if a control device is installed, the information should be for the control device's stack exit):

A. Height above grade (feet): 10.00 B. Inside Diameter at Exit (feet): 0.5 C. Exhaust Gas Volume (ACFM): 1,060

D. Base Elevation (feet): ~25 E. Exhaust Gas Temperature°F): 900 F. Are sampling ports available? (•) Yes ( ) No

G. UTM Coordinate (E-W) (km): 402.496 H. UTM Coordinate (N-S) (km): 3,429.809

10. Point Source Emissions (You must attach calculations and, if used as the basis for emission estimates, manufacturer specification sheets):

Pollutant	Uncontrolled[1] Potential Emission Rate		Controlled[1,2] Potential Emission Rate		Basis for Potential Emissions Calculation/Estimate (e.g. AP-42, Manufacturer Data)	Comment (Optional)
	lb/hr	ton/yr	lb/hr	ton/yr		
NOx						See Emissions Calculations in Appendix D.
CO						See Emissions Calculations in Appendix D.
VOC						See Emissions Calculations in Appendix D.
PM						See Emissions Calculations in Appendix D.
SO_2						See Emissions Calculations in Appendix D.
Formaldehyde						See Emission Calculations in Appendix D
Total HAP						See Emission Calculations in Appendix D

[1]Potential emissions should be calculated based on 8,760 hr/yr and maximum operation unless an enforceable limit will be applicable.

[2]If the pollutant is uncontrolled, leave blank.

11. Applicable Regulations (Mark all that apply):

- ☐ 40 CFR 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines
- ☐ 40 CFR 60, Subpart GG, NSPS for Stationary Gas Turbines
- ☐ 40 CFR 60, Subpart KKKK, NSPS for Stationary Combustion Turbines
- ☐ Other: _____
- ☒ 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE
- ☒ 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition ICE
- ☐ 40 CFR 60, Subpart JJJJ, NSPS for Stationary Spark Ignition ICE
- ☐ Other: _____

12. Regulatory Standards, Limitations, and Requirements:

A.

Pollutant/Parameter	Rate/Value	Units of Standard	Regulatory Basis[3]	Engine Potential Emission Rate (in units of standard)
Example: NOx + NMHC	*6.4*	*g/kW-hr*	*NSPS, Subpart IIII*	*4.95 g/kW-hr*
Example: Annual Operation	*6,000*	*hr/yr*	*SMS-PSD*	*NA*
See, Technical Support Document.				

[3]For federal regulations, specify which NSPS or NESHAP is the basis. If a synthetic minor limit is being requested or is already applicable, specify either SMS-PSD or SMS-Title V

B. For engines subject to emission standards under NSPS, Subpart IIII or NSPS, Subpart JJJJ, is this engine certified by the manufacturer pursuant to the applicable regulation to meet the applicable emission standards ? ○ N/A ○ No ● Yes (If yes, attach a copy of the certification)

C. For emergency or limited use engines, is this engine equipped with a non-resettable hour meter? ○ N/A ○ No ● Yes

13. Pollution Control Information:

A. Device/Technology Type(s):

- [x] No Controls
- [ ] Air-to-Fuel Ratio Controller
- [ ] Water or Steam Injection
- [ ] Low NO_X Burners
- [ ] Oxidation Catalyst
- [ ] Selective Non-catalytic Reduction (SNCR)
- [ ] Non-selective Catalytic Reduction (NSCR/3-way Catalyst)
- [ ] Selective Catalytic Reduction (SCR)
- [ ] Other: _____
- [ ] Other: _____
- [ ] Other: _____

B. Control Efficiencies (Typical Operation)

Pollutant	% Reduction
NOx	
CO	
VOC	
Formaldehyde	

C. Operational Parameters (if any):

14. Compliance Status:

Is this engine in compliance with all applicable air pollution rules and regulations? (●) Yes ( ) No (If "No", must attach ADEM Form 437)

15. Clarifying/Supplemental Information (Optional):

For additional information, see Technical Support Document.

Please provide the following for the person preparing this application:

Name (Print or Type): Nikia Howard Company/Affiliation: _____

Signature: Nikia Howard Date: 2/18/2020

Appendix B

Project Construction Schedule

Project Construction Schedule
Confidential Business Information

Appendix C

Plot Plan

EMISSIONS SOURCES – 2 UNIT OPTION

	EMISSIONS SOURCE	EASTING (FT)	NORTHING (FT)	ELEVATION (FT)	TIEDOWN
1	STACK - UNIT 8	1805168.91	363120.52	180.00	CL STACK
2	STACK - UNIT 9	1805586.10	362703.33	180.00	CL STACK
3	COOLING TOWER - UNIT 8	1805485.59	363104.64	30.00	CL TOWER
4	COOLING TOWER - UNIT 9	1805973.50	362616.74	30.00	CL TOWER
5	STANDBY DIESEL GENERATOR - UNIT 8	1805301.08	362946.60	17.75	CL SKID
6	STANDBY DIESEL GENERATOR - UNIT 9	1805718.28	362529.41	17.75	CL SKID
7	EMERGENCY DIESEL FIREWATER PUMP ENGINE	1805164.98	363284.89	10.00	CL PUMP HOUSE
8	AUXILIARY BOILER - UNIT 8	1805142.97	363157.75	70.00	CL STACK

NOTES:
1. LOCATIONS INDICATED ARE PRELIMINARY AND ARE SUBJECT TO CHANGE.
2. ELEVATIONS ARE MINIMUM HEIGHTS RELATIVE TO FINISHED GRADE EL 27'-6".
3. COORDINATE SYSTEM IS NAD83 ALABAMA WEST ZONE.

NOTES

1. THIS DRAWING IS THE BASIS FOR THE SITE ARRANGEMENT AND IS SUBJECT TO REVISIONS AS A RESULT OF DETAILED DESIGN AND DUE TO VARIATIONS IN SUPPLIERS OF MAJOR EQUIPMENT.
2. COORDINATE SYSTEM IS IN NAD83 ALABAMA WEST ZONE.

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
D	14/JAN/20	REVISED AUX BOILER STACK HEIGHT	M/W	DDO			
C	06/DEC/19	REMOVED U9 AUXILIARY BOILER	M/W	DDO			
B	03/OCT/19	REVISED U9 COOLING TOWER LOCATION	M/W	DDO			
A	25/SEP/19	INITIAL ISSUE	M/W	DDO			
E	04/FEB/20	UPDATED PROJECT TITLE	NSC	LM			

N

60' 30' 0 60' 120'
1"=60'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ALABAMA

SIGNED _____

DATE _____ REG NO. _____

BLACK & VEATCH

DESIGNER | DRAWN
CHECKED | DATE

ALABAMA POWER COMPANY
BARRY 8 COMBINED CYCLE PROJECT

PERMITTING SUPPORT SKETCH
EMMISSION POINTS - TWO UNIT

PROJECT | DRAWING NUMBER | REV
285100-DS-0002 | E

CODE
AREA

MicroStation v8.11.9.578
Full Size 1:1
car88101
AMERCAN
02/04/2020 07:11 PM

Appendix D

Emission Calculations

Table D-1

Emissions Calculations - Combined Cycle Units - Pre Upgrade Configuration

Maximum Heat Input (HHV)	4,771	MMBtu/hr (Pre-Upgrade Case 99, including DB firing rate)
Annual Average Heat Input (HHV)	4,596	MMBtu/hr (Pre-Upgrade Case 102, including DB firing rate)

	Summary of Short Term Emission Rates (lb/hr)												
	TSP[5/6/]	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Maximum hourly operating emission rates [1/2/3/]	6.45	21.08	21.08	38.0	23.1	13.2	8.02	0.00	0.00234	558,140	11	1	558,716
Annual average hourly operating emission rates [2/4/]	6.29	20.41	20.41	36.6	22.3	12.7	7.72	0.00	0.00225	537,622	10	1	538,177
Maximum Hourly Startup Emission Rates	6.09	12.38	12.38	102.0	1,673.6		4.27						
Maximum Hourly Shutdown Emission Rates	4.27	8.67	8.67	13.1	512.3		2.35						

	Summary of Worst-Case Annual Emission Totals (tons/yr)												
	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Worst-Case Annual Emissions [7/]	27.5	89.4	89.4	160.3	239.0	173.9	33.8	0.089	0.0099				2,357,217

	Assessment of worst-case annual emission totals (ton/yr)												
	TSP	PM10	PM2.5	NOx	CO	VOC	SO2	H2SO4	Lead	CO2	CH4	N2O	CO2e
1. Full Load Operation @ 8760 hrs/yr	**27.53**	**89.41**	**89.41**	**160.31**	97.67	55.63	**33.83**	0	**0.00987**	2,354,785	44	4	**2,357,217**
2. Accounting for SU/SD hours													
a. Startup Emissions	0.95	1.92	1.92	6.75	138.08	113.28	0.60	0.08	0.00018	41,977	0.8	0.08	42,021
b. Shutdown Emissions	0.07	0.14	0.14	0.22	8.52	8.00	0.04	0.005	0.00001	2,680	0.05	0.01	2,683
c. Operating Emissions	26.05	84.58	84.58	151.65	92.40	52.62	32.01	0	0.00934	2,227,625	41.98	4.20	2,229,925
Total Emissions	**27.06**	**86.65**	**86.65**	**158.62**	**239.00**	**173.90**	**32.65**	**0.09**	**0.00952**				**2,274,629**

Annual hours breakdown					
startup:	440	shutdown:	33	operating:	8,287

Startup and Shutdown Emission Input Summary

	Emissions (lbs/event)												
Type of Start / Events per Year / Duration (minutes)	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Cold Start / 25 / 233	15.77	32.07	32.07	172.26	2954.46	2056.02	10.46	1.46	0.00305	727,677	13.71	1.37	728,429
Warm Start / 34 / 200	13.48	27.40	27.40	148.78	2270.59	1875.65	8.87	1.24	0.00259	617,126	11.63	1.16	617,764
Hot Start / 111 / 124	9.36	19.03	19.03	37.30	1127.01	1003.55	5.80	0.81	0.00169	403,426	7.60	0.76	403,843
Shutdown / 170 / 12	0.84	1.70	1.70	2.57	100.29	94.10	0.45	0.06	0.00013	31,535	0.59	0.06	31,568

1/ Maximum short term NOx, CO and VOC emission rates are from Pre Upgrade Case 99

2/ Emission rates for SO2, lead, CO2, CH4 and N2O are calculated using emission factors from AP-42 Table 1.4-2 and 40 CFR Part 98 Tables C-1, C-2 and C-3

3/ Emission rate for H2SO4 calculated using EPRI methdology (see Table B-2)

4/ Annual average PM, NOx, CO, and VOC emission rates are from Pre Upgrade Case 102

5/ All FPM assumed to be < 10 microns; PM2.5 = PM10

6/ Short term and annual average TSP and PM10 emission rates are estimated by Alabama Power at the expected maximum gas sulfur content

7/ Worst-case emissions determined during normal operation for 8,760 hours per year or operations with expected startup/shutdown times.

Table D-2
H2SO4 Emissions Summary for Combined Cycle Units - Pre Upgrade Condition
Operating modes: normal operation, startup & shutdown

EPRI Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (3002012398); 2018 Update

Estimation of Sulfuric Acid Emissions from Combined Cycle Units

Combined Cycle, equipped with SCR and Ox Catalyst

Formation of sulfuric acid from the combustion of natural gas in a combined cycle unit is the result of three potential mechanisms (1) formation from sulfur contained in the fuel, (2) oxidation of SO_2 to SO_3 across the SCR catalyst, and (3) oxidation of SO_2 to SO_3 across the CO oxidation catalyst.

(1) Formation from the combustion of sulfur-containing fuels: (Equation 6-4)

$$EM_{CCcom} = K * F1 * E2_{NG}$$

Where:

EM_{CCcom} is sulfuric acid emissions from combustion (lb/yr)
K is a molecular weight and conversion constant
F1 is a fuel impact factor
$E2_{NG}$ is calculated or measured emissions of SO_2 (ton/yr)

The F1 factor for combined cycle combustion units is a function of stack temperature, as sulfuric acid vapor is related to the temperature of the exhaust. The following table combines the temperature-based SO_3 to H_2SO_4 conversion with the SO_2 to SO_3 conversion to yield the Fuel Impact Factor, F1.

Stack Temperature (^oF)	F1 Factor	
300	**0.055**	*Average Stack Temperature for CT's*
400	0.055	
500	0.047	
600	0.022	
700	0.0055	
750	0.0027	
800	0.0013	
850	0.00071	
900	0.00039	
950	0.00022	
1000	0.00013	
1050	0.00008	
1100	0.00005	
1150	0.00003	
1200	0.00002	

3,063	K, Molecular Weight and Conversion Constant
98.07	Molecular Weight of Sulfuric Acid
64.04	Molecular Weight of Sulfur Dioxide
2000	lb/ton, Conversion Factor

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
8.02	2.69	2.66	2.81	2.31	lb/hr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Maximum Hourly)**
0.68	0.23	0.22	0.24	0.19	lb/hr, Emissions of Sulfuric Acid from Natural Gas Combustion **(Maximum Hourly)**
33.83	0.13	0.15	0.32	0.04	tons/yr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Annual Average)**
5,699.21	22.01	25.39	54.19	6.49	lb/yr, Emissions of Sulfuric Acid from Natural Gas Combustion **(Annual Average)**

(2) Oxidation of SO_2 to SO_3 Across the SCR Catalyst (Equation 6-5)

$$EM_{CCSCR} = K * S3 * f_{Sops} * E2$$

Where:
EM_{CCSCR} is the total Sulfuric Acid from the SCR Catalyst
K is a molecular weight and conversion constant
S3 is the Catalyst Conversion Rate (Default is 0.03)
f_{Sops} is the operating factor of the SCR Catalyst System
E2 is calculated or measured emissions of SO_2 (ton/yr)

3,063	K, Molecular Weight and Conversion Constant
0.03	SCR Catalyst Conversion Rate
1	Operating Factor if the SCR Catalyst System (0 means not installed)

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
8.02	2.69	2.66	2.81	2.31	lb/hr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Maximum Hourly)**
33.83	0.13	0.15	0.32	0.04	tons/yr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Annual Average)**
0.37	0.12	0.12	0.13	0.11	lb/hr, Emissions of Sulfuric Acid from SCR Catalyst (**Maximum Hourly**)
3,108.66	12.01	13.85	29.56	3.54	lb/yr, Emissions of Sulfuric Acid from SCR Catalyst **(Annual Average)**

(3) Oxidation of SO_2 to SO_3 Across the CO Oxidation Catalyst

$$EM_{CC_CO} = [(K * E2) - EM_{CCSCR}] * F_{COops} * S2 * F3_{CO}$$ (Equation 6-6)

Where:
EM_{CC_CO} is the total Sulfuric Acid from the CO Oxidation Catalyst
K is a molecular weight and conversion constant
E2 is calculated or measured emissions of SO_2 (ton/yr)
EM_{CCSCR} is the total Sulfuric Acid from the SCR Catalyst
S2 is the Catalyst Conversion Rate (Default is 0.1)
f_{COops} is the operating factor of the SCR Catalyst System
$F3_{CO}$ Technology Impact Factor fo CO Catalyst

3,063	K, Molecular Weight and Conversion Constant
1	Operating Factor if the CO Catalyst System (0 means not installed)
0.10	CO Catalyst Conversion Rate
1	CO Catalyst Technology Impact Factor

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
8.02	2.69	2.66	2.81	2.31	lb/hr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Maximum Hourly)**
33.83	0.13	0.15	0.32	0.04	tons/yr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Annual Average)**
0.37	0.12	0.12	0.13	0.11	lb/hr, Emissions of Sulfuric Acid from SCR Catalyst (**Maximum Hourly**)
3,108.66	12.01	13.85	29.56	3.54	lb/yr, Emissions of Sulfuric Acid from SCR Oxidation Catalyst **(Annual Average)**
1.19	0.40	0.39	0.42	0.34	lb/hr, Emissions of Sulfuric Acid from CO Oxidation (**Maximum Hourly**)
10,051.33	38.83	44.78	95.57	11.44	lb/yr, Emissions of Sulfuric Acid from CO Oxidation Catalyst **(Annual Average)**

(4) The total amount of Sulfuric Acid generated may be summarized by the following equation.

18,859.21	72.85	84.02	179.32	21.47	lb/yr, Sulfuric Acid Generated **(Annual Average)**

(5) Emissions of Sulfuric Acid are reduced by the reducing effect of ammonia slip in the unit:

$$TSAR_{CC} = \left[TSAM_{CC} - \left(K_S * B * f_{sreagent} * S_{NH_3}\right)\right] * F2_{CC}$$ (Equation 6-8)

Where:

$TSAR_{CC}$ is the final emission rate of sulfuric acid

$TSAM_{CC}$ is the sulfuric acid generated

K_s is a conversion constant

B is the total fuel burn in TBtu/yr

$f_{sreagent}$ is the fraction of SCR operation with reagent

S_{NH3} actual NH_3 slip at 6% O_2, wet

$F2_{CC}$ is the technology impact factor for CC heat exchangers

3,799.00	K, Conversion Constant
0.50	CC Heat Exchanger Technology Impact Factor

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
5.00	5.00	5.00	5.00	5.00	ppmd, Measured Ammonia Slip
8.24	11.70	11.70	11.70	11.70	Estimated Annual Average O_2 Concentration in Exhaust Stream
12.39	9.13	9.13	9.13	9.13	Estimated Annual Average Moisture Concentration in Exhaust Stream
6.72	8.91	8.91	8.91	8.91	ppmw @ 6% O_2, Ammonia Slip
4,596.00	1,600.46	1,581.04	1,670.66	1,377.00	Mode Fuel Firing Rate (MMBtu/hr, annual average)
8,760	97.17	113.45	229.14	33.28	Mode Operating Schedule (hrs/yr)
40.26	0.16	0.18	0.38	0.05	TBtu/yr, Mode Fuel Throughput **(Annual Average)**
1	0	0	0	0	Fraction of Time the SCR is in Service
2.24	0.75	0.74	0.78	0.65	lb/hr, Sulfuric Acid Generated **(Maximum Hourly)**
18,859.21	72.85	84.02	179.32	21.47	lb/yr, Sulfuric Acid Generated **(Annual Average)**
0.00	0.37	0.37	0.39	0.32	lb/hr, Sulfuric Acid Emissions **(Maximum Hourly)**
0.00	36.42	42.01	89.66	10.73	lb/yr, Sulfuric Acid Emissions **(Annual Average)**

Table D-3
CT and HRSG Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates - Pre Upgrade Configuration

Pollutant	CTG Emission Factor AP-42 Section 3.1-3 04/00 - Combustion Turbine Natural Gas			Duct Burner Emission Factor AP-42 Section 1.4 07/98 - Natural Gas Combustion			Total Emissions: Emission Rate, (1 CT/HRSG)			Total Emissions: Emission Rate, (2 CT/HRSGs)		
	(lb/10^{6}scf)	(lb/MMBtu) [a]	Rating	(lb/10^{6}scf)	(lb/MMBtu) [a]	Rating	Max Hourly [d] (lb/hr)	Daily [h] (lb/day)	Annual [e] (tpy)	Max Hourly [d] (lb/hr)	Daily [h] (lb/day)	Annual [e] (tpy)
Metal Compounds:												
Arsenic [g]	2.00E-04	1.96E-07	(i)	2.00E-04	1.96E-07	E	9.36E-04	2.25E-02	4.10E-03	1.87E-03	4.49E-02	8.20E-03
Beryllium [g]	1.20E-05	1.18E-08	(i)	1.20E-05	1.18E-08	E	5.62E-05	1.35E-03	2.46E-04	1.12E-04	2.70E-03	4.92E-04
Cadmium [g]	1.10E-03	1.08E-06	(i)	1.10E-03	1.08E-06	D	5.15E-03	1.24E-01	2.25E-02	1.03E-02	2.47E-01	4.51E-02
Chromium (total) [g]	1.40E-03	1.37E-06	(i)	1.40E-03	1.37E-06	D	6.55E-03	1.57E-01	2.87E-02	1.31E-02	3.14E-01	5.74E-02
Cobalt [g]	8.40E-05	8.24E-08	(i)	8.40E-05	8.24E-08	D	3.93E-04	9.43E-03	1.72E-03	7.86E-04	1.89E-02	3.44E-03
Lead [g]	5.00E-04	4.90E-07	(i)	5.00E-04	4.90E-07	D	2.34E-03	5.62E-02	1.02E-02	4.68E-03	1.12E-01	2.05E-02
Manganese [g]	3.80E-04	3.73E-07	(i)	3.80E-04	3.73E-07	D	1.78E-03	4.27E-02	7.79E-03	3.56E-03	8.54E-02	1.56E-02
Mercury [g]	2.60E-04	2.55E-07	(i)	2.60E-04	2.55E-07	D	1.22E-03	2.92E-02	5.33E-03	2.43E-03	5.84E-02	1.07E-02
Nickel [g]	2.10E-03	2.06E-06	(i)	2.10E-03	2.06E-06	C	9.83E-03	2.36E-01	4.30E-02	1.97E-02	4.72E-01	8.61E-02
Selenium [g]	2.40E-05	2.35E-08	(i)	2.40E-05	2.35E-08	E	1.12E-04	2.70E-03	4.92E-04	2.25E-04	5.39E-03	9.84E-04
Organic Compounds:												
Acetaldehyde		4.00E-05	C		4.00E-05	(j)	1.91E-01	4.58E+00	8.36E-01	3.82E-01	9.16E+00	1.67E+00
Acrolein		6.40E-06	C		6.40E-06	(j)	3.05E-02	7.33E-01	1.34E-01	6.11E-02	1.47E+00	2.68E-01
Benzene		1.20E-05	A		1.20E-05	(j)	5.73E-02	1.37E+00	2.51E-01	1.15E-01	2.75E+00	5.02E-01
Ethylbenzene		3.20E-05	C		3.20E-05	(j)	1.53E-01	3.67E+00	6.69E-01	3.05E-01	7.33E+00	1.34E+00
Formaldehyde		(f)					1.09E+00	2.62E+01	4.74E+00	2.18E+00	5.24E+01	9.48E+00
Naphthalene		1.30E-06	C	6.10E-04	1.30E-06	(j)	6.21E-03	1.49E-01	2.72E-02	1.24E-02	2.98E-01	5.44E-02
PAHs		2.20E-06	C		2.20E-06	(j)	1.05E-02	2.52E-01	4.60E-02	2.10E-02	5.04E-01	9.20E-02
Toluene		1.30E-04		3.40E-03	1.30E-04	(j)	6.21E-01	1.49E+01	2.72E+00	1.24E+00	2.98E+01	5.44E+00
Xylene		6.40E-05	C		6.40E-05	(j)	3.05E-01	7.33E+00	1.34E+00	6.11E-01	1.47E+01	2.68E+00

	CTG	Duct Burner
Max Heat Input per Turbine(MMBtu/hr)	3,831	942
Max Operating hours per year	**8,760**	**8,760**
Total Heat Input per Turbine(MMBtu/yr)	33,559,560	8,255,424

CC Unit Total (tpy)	**10.88**	Per Turbine
Max single HAP (tpy)	**4.74**	Per Turbine

Operation (hr/day) 24.00
Natural Gas Heating Value 1,020 Btu/SCF (HHV)

Notes:
(a) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf) if lb/10^6 scf is given.
(b) Max Hourly Emission Rate (lb/hr) = [Max Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)]
(c) Annual Emission Rate (ton/yr) = [Heat Input (MMBtu/yr) * Emission Factor (lb/MMBtu) / 2000 lb/ton]
(d) Total Max Hourly Emissions (lb/hr) = CTG Gas Emissions (lb/hr) + Duct Burner Emissions (lb/hr), if fuel oil operating hours = 0
Total Max Hourly Emissions (lb/hr) = Maximum[CTG Oil Emissions (lb/hr) or [CTG Gas Emissions (lb/hr) + Duct Burner Emissions (lb/hr)]], if fuel oil operating hours > 0
(e) Total Annual Emissions (ton/yr) = [CTG Oil Emissions (ton/yr) + CTG Gas Emissions (ton/yr) + Duct Burner Emissions (ton/yr)]
(f) Vendor-supplied emission estimate
(g) Emission Factor for natural gas from AP-42 Section 1.4 07/98 - Natural Gas Combustion.
(h) Daily emission rate (lb/day) = maximum hourly emission rate (lb/hr) * (maximum operating hours per year (hr/yr) / 365 days/year)
(i) Toxic emissions are reported on a combined unit basis (CT plus HRSG). Emission factor for HRSG is greater than emission factor for CT and used for both units for conservatism
(j) Toxic emissions are reported on a combined unit basis (CT plus HRSG). Emission factor for CT is greater than emission factor for HRSG and used for both units for conservatism

Table D-4
Combustion Turbine Performance Data - Pre Upgrade Condition

Confidential Business Information

Table D-5
Emissions Calculations - Combined Cycle Units - Post Upgrade Configuration

Maximum Heat Input (HHV)	4,883	MMBtu/hr (Post-Upgrade Case 43, including DB firing rate)
Annual Average Heat Input (HHV)	4,767	MMBtu/hr (Post-Upgrade Case 47, including DB firing rate)

	Summary of Short Term Emission Rates (lb/hr)												
	TSP[5/6/]	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Maximum hourly operating emission rates [1/2/3/]	6.77	21.51	21.51	39.1	23.8	13.6	8.21	0.00	0.00239	571,218	11	1	571,808
Annual average hourly operating emission rates [2/4/]	6.55	20.59	20.59	38.2	23.2	13.3	8.01	0.00	0.00234	557,648	11	1	558,224
Maximum Hourly Startup Emission Rates	6.5	13.3	13.30	109.4	1,676.7		4.57						
Maximum Hourly Shutdown Emission Rates	4.58	9.35	9.35	14.3	551.1		2.52						

	Summary of Worst-Case Annual Emission Totals (tons/yr)												
	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Worst-Case Annual Emissions [7/]	28.7	90.2	90.2	167.3	249.9	185.3	35.1	0.096	0.0102				2,445,022

	Assment of Worst-Case Annual Emission Totals (ton/yr)												
	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
1. Full Load Operation @ 8760 hrs/yr	**28.69**	**90.20**	**90.20**	**167.32**	**101.62**	**58.25**	**35.09**	**0**	**0.01024**	**2,442,500**	**46**	**5**	**2,445,022**
2. Accounting for SU/SD hours				Annual hours breakdown									
				startup:	440	shutdown:	33	operating:	8,287				
a. Startup Emissions	1.03	2.09	2.09	7.13	144.63	121.85	0.65	0.09	0.00019	44,967	0.8	0.08	45,013
b. Shutdown Emissions	0.08	0.16	0.16	0.24	9.17	8.38	0.04	0.006	0.00001	2,873	0.05	0.01	2,876
c. Operating Emissions	27.14	85.33	85.33	158.28	96.13	55.11	33.20	0	0.00968	2,310,603	43.55	4.35	2,312,989
Total Emissions	**28.25**	**87.58**	**87.58**	**165.65**	**249.93**	**185.34**	**33.89**	**0.10**	**0.00988**				**2,360,878**

Startup and Shutdown Emission Input Summary													
	Emissions (lbs/event)												
Type of Start / Events per Year / Duration (minutes)	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Cold Start / 25 / 233	16.99	34.65	34.65	183.00	3017.01	2207.65	11.20	1.56	0.00327	779,875	14.70	1.47	780,680
Warm Start / 34 / 200	15.07	30.74	30.74	150.31	2348.17	2024.68	9.50	1.32	0.00277	661,353	12.46	1.25	662,036
Hot Start / 111 / 124	10.05	20.49	20.49	41.20	1207.20	1078.14	6.21	0.86	0.00181	431,983	8.14	0.81	432,430
Shutdown / 170 / 12	0.90	1.83	1.83	2.79	107.90	98.60	0.49	0.07	0.00014	33,796	0.64	0.06	33,831

1/ Maximum short term NO_X, CO and VOC emission rates are from Post Upgrade Case 43

2/ Emission rates for SO_2, lead, CO_2, CH_4 and N_2O are calculated using emission factors from AP-42 Table 1.4-2 and 40 CFR Part 98 Tables C-1, C-2, and C-3.

3/ Emission rate for H_2SO_4 calculated using EPRI methdology (see CC H_2SO_4 tab)

4/ Annual average PM, NO_X, CO, and VOC emission rates are from Post Upgrade Case 47

5/ All FPM assumed to be < 10 microns; $PM_{2.5} = PM_{10}$

6/ Short term and annual average TSP and PM_{10} emission rates are estimated to correspond to the expected maximum pipeline gas sulfur content

7/ Worst-case emissions determined during normal operation for 8,760 hours per year or operations with expected startup/shutdown times.

Table D-6
H2SO4 Emissions Summary for Combined Cycle Units - Post Upgrade Condition
Operating modes: normal operation, startup & shutdown

EPRI Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (3002012398); 2018 Update

Estimation of Sulfuric Acid Emissions from Combined Cycle Units

Combined Cycle, equipped with SCR and Ox Catalyst

Formation of sulfuric acid from the combustion of natural gas in a combined cycle unit is the result of three potential mechanisms (1) formation from sulfur contained in the fuel, (2) oxidation of SO_2 to SO_3 across the SCR catalyst, and (3) oxidation of SO_2 to SO_3 across the CO oxidation catalyst.

(1) Formation from the combustion of sulfur-containing fuels: (Equation 6-4)

$$EM_{CCcom} = K * F1 * E2_{NG}$$

Where:
EM_{CCcom} is sulfuric acid emissions from combustion (lb/yr)
K is a molecular weight and conversion constant
F1 is a fuel impact factor
$E2_{NG}$ is calculated or measured emissions of SO_2 (ton/yr)

The F1 factor for combined cycle combustion units is a function of stack temperature, as sulfuric acid vapor is related to the temperature of the exhaust. The following table combines the temperature-based SO_3 to H_2SO_4 conversion with the SO_2 to SO_3 conversion to yield the Fuel Impact Factor, F1.

Stack Temperature (^oF)	F1 Factor	
300	**0.055**	*Average Stack Temperature for CT's*
400	0.055	
500	0.047	
600	0.022	
700	0.0055	
750	0.0027	
800	0.0013	
850	0.00071	
900	0.00039	
950	0.00022	
1000	0.00013	
1050	0.00008	
1100	0.00005	
1150	0.00003	
1200	0.00002	

3,063	K, Molecular Weight and Conversion Constant
98.07	Molecular Weight of Sulfuric Acid
64.04	Molecular Weight of Sulfur Dioxide
2000	lb/ton, Conversion Factor

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
8.21	2.88	2.85	3.01	2.48	lb/hr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Maximum Hourly)**
0.69	0.24	0.24	0.25	0.21	lb/hr, Emissions of Sulfuric Acid from Natural Gas Combustion **(Maximum Hourly)**
35.09	0.14	0.16	0.34	0.04	tons/yr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Annual Average)**
5,911.50	23.59	27.21	58.03	6.95	lb/yr, Emissions of Sulfuric Acid from Natural Gas Combustion **(Annual Average)**

(2) Oxidation of SO_2 to SO_3 Across the SCR Catalyst (Equation 6-5)

$$EM_{CCSCR} = K * S3 * f_{Sops} * E2$$

Where: EM_{CCSCR} is the total Sulfuric Acid from the SCR Catalyst
K is a molecular weight and conversion constant
S3 is the Catalyst Conversion Rate (Default is 0.03)
f_{Sops} is the operating factor of the SCR Catalyst System
E2 is calculated or measured emissions of SO_2 (ton/yr)

3,063 K, Molecular Weight and Conversion Constant
0.03 SCR Catalyst Conversion Rate
1 Operating Factor if the SCR Catalyst System (0 means not installed)

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
8.21	2.88	2.85	3.01	2.48	lb/hr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Maximum Hourly)**
35.09	0.14	0.16	0.34	0.04	tons/yr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Annual Average)**
0.38	0.13	0.13	0.14	0.11	lb/hr, Emissions of Sulfuric Acid from SCR Catalyst (**Maximum Hourly**)
3,224.46	12.87	14.84	31.65	3.79	lb/yr, Emissions of Sulfuric Acid from SCR Catalyst **(Annual Average)**

(3) Oxidation of SO_2 to SO_3 Across the CO Oxidation Catalyst

$$EM_{CC_CO} = [(K * E2) - EM_{CCSCR}] * F_{COops} * S2 * F3_{CO}$$

(Equation 6-6)

Where: EM_{CC_CO} is the total Sulfuric Acid from the CO Oxidation Catalyst
K is a molecular weight and conversion constant
E2 is calculated or measured emissions of SO_2 (ton/yr)
EM_{CCSCR} is the total Sulfuric Acid from the SCR Catalyst
S2 is the Catalyst Conversion Rate (Default is 0.1)
f_{COops} is the operating factor of the SCR Catalyst System
$F3_{CO}$ Technology Impact Factor fo CO Catalyst

3,063 K, Molecular Weight and Conversion Constant
1 Operating Factor if the CO Catalyst System (0 means not installed)
0.10 CO Catalyst Conversion Rate
1 CO Catalyst Technology Impact Factor

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
8.21	2.88	2.85	3.01	2.48	lb/hr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Maximum Hourly)**
35.09	0.14	0.16	0.34	0.04	tons/yr, Estimated Sulfur Dioxide CT/HRSG Emissions **(Annual Average)**
0.38	0.13	0.13	0.14	0.11	lb/hr, Emissions of Sulfuric Acid from SCR Catalyst (**Maximum Hourly**)
3,224.46	12.87	14.84	31.65	3.79	lb/yr, Emissions of Sulfuric Acid from SCR Oxidation Catalyst **(Annual Average)**
1.22	0.43	0.42	0.45	0.37	lb/hr, Emissions of Sulfuric Acid from CO Oxidation (**Maximum Hourly**)
10,425.75	41.61	47.99	102.34	12.26	lb/yr, Emissions of Sulfuric Acid from CO Oxidation Catalyst **(Annual Average)**

(4) The total amount of Sulfuric Acid generated may be summarized by the following equation.

19,561.71	78.07	90.04	192.01	23.01	lb/yr, Sulfuric Acid Generated **(Annual Average)**

(5) Emissions of Sulfuric Acid are reduced by the reducing effect of ammonia slip in the unit:

$$TSAR_{CC} = \left[TSAM_{CC} - \left(K_S * B * f_{sreagent} * S_{NH_3}\right)\right] * F2_{CC}$$ (Equation 6-8)

Where: $TSAR_{CC}$ is the final emission rate of sulfuric acid

$TSAM_{CC}$ is the sulfuric acid generated

K_S is a conversion constant

B is the total fuel burn in TBtu/yr

$f_{sreagent}$ is the fraction of SCR operation with reagent

S_{NH3} actual NH_3 slip at 6% O_2, wet

$F2_{CC}$ is the technology impact factor for CC heat exchangers

3,799.00 K, Conversion Constant

0.50 CC Heat Exchanger Technology Impact Factor

Mode of Operation					
Operating	**Cold Start**	**Warm Start**	**Hot Start**	**Shut Down**	
5.00	5.00	5.00	5.00	5.00	ppmd, Measured Ammonia Slip
8.24	11.59	11.59	11.59	11.59	Estimated Annual Average O_2 Concentration in Exhaust Stream
12.40	9.22	9.22	9.22	9.22	Estimated Annual Average Moisture Concentration in Exhaust Stream
6.72	8.81	8.81	8.81	8.81	ppmw @ 6% O_2, Ammonia Slip
4,767.20	1,715.27	1,694.34	1,788.92	1,475.71	Mode Fuel Firing Rate (MMBtu/hr, annual average)
8,760	97.17	113.45	229.14	33.28	Mode Operating Schedule (hrs/yr)
41.76	0.17	0.19	0.41	0.05	TBtu/yr, Mode Fuel Throughput **(Annual Average)**
1	0	0	0	0	Fraction of Time the SCR is in Service
2.29	0.80	0.79	0.84	0.69	lb/hr, Sulfuric Acid Generated **(Maximum Hourly)**
19,561.71	78.07	90.04	192.01	23.01	lb/yr, Sulfuric Acid Generated **(Annual Average)**
0.00	0.40	0.40	0.42	0.35	lb/hr, Sulfuric Acid Emissions **(Maximum Hourly)**
0.00	39.04	45.02	96.01	11.50	lb/yr, Sulfuric Acid Emissions **(Annual Average)**

Table D-7
CT and HRSG Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates - Post Upgrade Configuration

Pollutant	CTG Emission Factor AP-42 Section 3.1-3 04/00 - Combustion Turbine Natural Gas			Duct Burner Emission Factor AP-42 Section 1.4 07/98 - Natural Gas Combustion			Total Emissions: Emission Rates 1 CT/HRSG			Total Emissions: Emission Rates 2 CT/HRSGs		
	(lb/10^{6}scf)	(lb/MMBtu) [a]	Rating	(lb/10^{6}scf)	(lb/MMBtu) [a]	Rating	Max Hourly [d] (lb/hr)	Daily [h] (lb/day)	Annual [e] (tpy)	Max Hourly [d] (lb/hr)	Daily [h] (lb/day)	Annual [e] (tpy)
Metal Compounds:												
Arsenic [g]	2.00E-04	1.96E-07	(i)	2.00E-04	1.96E-07	E	9.62E-04	2.31E-02	4.21E-03	1.92E-03	4.62E-02	8.42E-03
Beryllium [g]	1.20E-05	1.18E-08	(i)	1.20E-05	1.18E-08	E	5.77E-05	1.38E-03	2.53E-04	1.15E-04	2.77E-03	5.05E-04
Cadmium [g]	1.10E-03	1.08E-06	(i)	1.10E-03	1.08E-06	D	5.29E-03	1.27E-01	2.32E-02	1.06E-02	2.54E-01	4.63E-02
Chromium (total) [g]	1.40E-03	1.37E-06	(i)	1.40E-03	1.37E-06	D	6.73E-03	1.62E-01	2.95E-02	1.35E-02	3.23E-01	5.90E-02
Cobalt [g]	8.40E-05	8.24E-08	(i)	8.40E-05	8.24E-08	D	4.04E-04	9.69E-03	1.77E-03	8.08E-04	1.94E-02	3.54E-03
Lead [g]	5.00E-04	4.90E-07	(i)	5.00E-04	4.90E-07	D	2.40E-03	5.77E-02	1.05E-02	4.81E-03	1.15E-01	2.11E-02
Manganese [g]	3.80E-04	3.73E-07	(i)	3.80E-04	3.73E-07	D	1.83E-03	4.38E-02	8.00E-03	3.65E-03	8.77E-02	1.60E-02
Mercury [g]	2.60E-04	2.55E-07	(i)	2.60E-04	2.55E-07	D	1.25E-03	3.00E-02	5.48E-03	2.50E-03	6.00E-02	1.10E-02
Nickel [g]	2.10E-03	2.06E-06	(i)	2.10E-03	2.06E-06	C	1.01E-02	2.42E-01	4.42E-02	2.02E-02	4.85E-01	8.84E-02
Selenium [g]	2.40E-05	2.35E-08	(i)	2.40E-05	2.35E-08	E	1.15E-04	2.77E-03	5.05E-04	2.31E-04	5.54E-03	1.01E-03
Organic Compounds:												
Acetaldehyde		4.00E-05	C		4.00E-05	(j)	1.96E-01	4.71E+00	8.59E-01	3.92E-01	9.42E+00	1.72E+00
Acrolein		6.40E-06	C		6.40E-06	(j)	3.14E-02	7.53E-01	1.37E-01	6.28E-02	1.51E+00	2.75E-01
Benzene		1.20E-05	A		1.20E-05	(j)	5.89E-02	1.41E+00	2.58E-01	1.18E-01	2.82E+00	5.16E-01
Ethylbenzene		3.20E-05	C		3.20E-05	(j)	1.57E-01	3.77E+00	6.87E-01	3.14E-01	7.53E+00	1.37E+00
Formaldehyde		(f)					1.15E+00	2.76E+01	4.95E+00	2.30E+00	5.52E+01	9.89E+00
Naphthalene		1.30E-06	C		1.30E-06	(j)	6.38E-03	1.53E-01	2.79E-02	1.28E-02	3.06E-01	5.58E-02
PAHs		2.20E-06	C		2.20E-06	(j)	1.08E-02	2.59E-01	4.73E-02	2.16E-02	5.18E-01	9.45E-02
Toluene		1.30E-04	C		1.30E-04	(j)	6.38E-01	1.53E+01	2.79E+00	1.28E+00	3.06E+01	5.58E+00
Xylene		6.40E-05	C		6.40E-05	(j)	3.14E-01	7.53E+00	1.37E+00	6.28E-01	1.51E+01	2.75E+00

	CTG	Duct Burner
Max Heat Input per Turbine(MMBtu/hr)	3,987	917
Max Operating hours per year	**8,760**	**8,760**
Total Heat Input per Turbine(MMBtu/yr)	34,926,120	8,034,672

CC Unit Total (tpy)	**11.26**	Per Turbine
Max single HAP (tpy)	**4.95**	Per Turbine

Operation (hr/day) 24.00
Natural Gas Heating Value 1,020 Btu/SCF (HHV)

Notes:
(a) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf) if lb/10^6 scf is given.
(b) Max Hourly Emission Rate (lb/hr) = [Max Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)]
(c) Annual Emission Rate (ton/yr) = [Heat Input (MMBtu/yr) * Emission Factor (lb/MMBtu) / 2000 lb/ton]
(d) Total Max Hourly Emissions (lb/hr) = CTG Gas Emissions (lb/hr) + Duct Burner Emissions (lb/hr), if fuel oil operating hours = 0
Total Max Hourly Emissions (lb/hr) = Maximum[CTG Oil Emissions (lb/hr) or [CTG Gas Emissions (lb/hr) + Duct Burner Emissions (lb/hr)]], if fuel oil operating hours > 0
(e) Total Annual Emissions (ton/yr) = [CTG Oil Emissions (ton/yr) + CTG Gas Emissions (ton/yr) + Duct Burner Emissions (ton/yr)]
(f) Vendor-supplied emission estimate
(g) Emission Factor for natural gas from AP-42 Section 1.4 07/98 - Natural Gas Combustion.
(h) Daily emission rate (lb/day) = maximum hourly emission rate (lb/hr) * (maximum operating hours per year (hr/yr) / 365 days/year)
(i) Toxic emissions are reported on a combined unit basis (CT plus HRSG). Emission factor for HRSG is greater than emission factor for CT and used for both units for conservatism
(j) Toxic emissions are reported on a combined unit basis (CT plus HRSG). Emission factor for CT is greater than emission factor for HRSG and used for both units for conservatism

Table D-8
Combustion Turbine Performance Data - Post Upgrade Condition

Confidential Business Information

Table D-9

Auxiliary Boiler Criteria Pollutant Emissions

Annual and Maximum Hourly Emission Rates

Emission Source	Auxiliary Boiler
Source Type	Natural Gas-Fired Boiler
Heat Input (MMBtu/hr)	90.5
Maximum Fuel Usage (MMcf/hr)	0.0887
Number of Units	1
Natural Gas Heating Value (Btu/scf)	1,020
Sulfur Content of Natural Gas (gr S /100 scf)	0.60
Annual Capacity Factor (%)	100

	Emission Factor (lb/MMBtu)	**Hourly (g) (Lbs/Hr) Dominion 2**	**Annual (h) (ton/year) Dominion 2**
TSP (a)	0.0019	0.17	0.75
PM_{10} (a)	0.0075	0.679	2.97
$PM_{2.5}$ (a)	0.0075	0.679	2.97
Nitrogen Oxides (a)	0.011	1.00	4.36
Carbon Monoxide (a)	0.037	3.35	14.67
VOC (a)	0.0040	0.36	1.59
Sulfur Oxides (b)	1.68E-03	0.152	0.67
H_2SO_4 (c)	2.57E-05	2.3E-03	1.0E-02
Lead (d)	4.9E-07	4.4E-05	1.9E-04
CO_2 (e)	116.98	10,586	46,368
CH_4 (e)	0.00220	2.0E-01	8.7E-01
N_2O (e)	0.00022	2.0E-02	8.7E-02
CO_2e (f)			46,416

Notes:

(a) Emission factors from vendor data provided by Alabama Power 4/15/19. NOx emission factor assumes use of Low NOx burner

(b) SO_2 emission factor assumes 100% conversion of sulfur in gas to SO_2

(c) H_2SO_4 emissions assume 1% conversion of SO_2 to SO_3 (Basis: EPRI "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (3002012398)"; 2018 Update, Table 4-1).

(d) Emission factor for lead is from USEPA AP-42, Section 1.4, Table 1.4-2, dated July 1998

(e) Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2 (amended 12/9/2016)

(f) Global Warming Potentials for GHGs are from Federal Register Vol. 78, No. 230, November

(g) Hourly Emission Rate (lb/hr) = Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)

(h) Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Annual Operating Hours (hr/

Table D-10
Auxiliary Boiler Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates

Compound Categories	Emission Factor		Emission Est. Method	Emission Rate		
	Value	Units		Max Hourly (lb/hr)	Max Daily (lb/day)	Annual (tpy)
Metal Compounds:						
Arsenic	2.00E-04	lb/MMcf	1	1.77E-05	4.26E-04	7.77E-05
Beryllium	1.20E-05	lb/MMcf	1	1.06E-06	2.56E-05	4.66E-06
Cadmium	1.10E-03	lb/MMcf	1	9.76E-05	2.34E-03	4.27E-04
Chromium (Total)	1.40E-03	lb/MMcf	1	1.24E-04	2.98E-03	5.44E-04
Cobalt	8.40E-05	lb/MMcf	1	7.45E-06	1.79E-04	3.26E-05
Lead	5.00E-04	lb/MMcf	1	4.44E-05	1.06E-03	1.94E-04
Manganese	3.80E-04	lb/MMcf	1	3.37E-05	8.09E-04	1.48E-04
Mercury	2.60E-04	lb/MMcf	1	2.31E-05	5.54E-04	1.01E-04
Nickel	2.10E-03	lb/MMcf	1	1.86E-04	4.47E-03	8.16E-04
Selenium	2.40E-05	lb/MMcf	1	2.13E-06	5.11E-05	9.33E-06
Organic Compounds:						
Benzene	2.10E-03	lb/MMcf	2	1.86E-04	4.47E-03	8.16E-04
Dichlorobenzene	1.20E-03	lb/MMcf	2	1.06E-04	2.56E-03	4.66E-04
Formaldehyde	0.075	lb/MMcf	2	6.65E-03	1.60E-01	2.91E-02
Hexane	1.80	lb/MMcf	2	1.60E-01	3.83E+00	7.00E-01
Naphthalene	6.10E-04	lb/MMcf	2	5.41E-05	1.30E-03	2.37E-04
Toluene	3.40E-03	lb/MMcf	2	3.02E-04	7.24E-03	1.32E-03
Polycyclic Organic Matter:						
Acenaphthene	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Acenaphthylene	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Anthracene	2.40E-06	lb/MMcf	2	2.13E-07	5.11E-06	9.33E-07
Benz(a)anthracene	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Benzo(a)pyrene	1.20E-06	lb/MMcf	2	1.06E-07	2.56E-06	4.66E-07
Benzo(b)fluoranthene	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Benzo(g,h,i)perylene	1.20E-06	lb/MMcf	2	1.06E-07	2.56E-06	4.66E-07
Benzo(k)fluoranthene	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Chrysene	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Dibenzo(a,h)anthracene	1.20E-06	lb/MMcf	2	1.06E-07	2.56E-06	4.66E-07
Dimethylbenz(a)Anthracene, 7,12-	1.60E-05	lb/MMcf	2	1.42E-06	3.41E-05	6.22E-06
Fluoranthene	3.00E-06	lb/MMcf	2	2.66E-07	6.39E-06	1.17E-06
Fluorene	2.80E-06	lb/MMcf	2	2.48E-07	5.96E-06	1.09E-06
Indo(1,2,3-cd)pyrene	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Methylchloanthrene, 3-	1.80E-06	lb/MMcf	2	1.60E-07	3.83E-06	7.00E-07
Methylnaphthalene, 2-	2.40E-05	lb/MMcf	2	2.13E-06	5.11E-05	9.33E-06
Phenanthrene	1.70E-05	lb/MMcf	2	1.51E-06	3.62E-05	6.61E-06
Pyrene	5.00E-06	lb/MMcf	2	4.44E-07	1.06E-05	1.94E-06

1 - AP-42 Table 1.4-4 (7/98) Emission Factors for Metals from Natural Gas Combustion

2 - AP-42 Table 1.4-3 (7/98) Emission Factors For Speciated Organic Compounds from Natural Gas Combustion

Table D-11
Cooling Tower Emissions
Annual and Maximum Hourly Emission Rates

Operating Water Circulation Rate (all cells)	(GPM)	182,650
Design Water Circulation Rate (a) all cells	(GPM)	219,180
No of Cells		14
Total Liquid Drift (b)	(%)	0.0005
Expected TDS/TSS of Circulated Water (c)	(ppmw)	5,000
Weight % PM_{10} in Particulate Emissions (e)		49.8%
Weight % $PM_{2.5}$ in Particulate Emissions (e)		0.196%
Emission Rate - Total Cooling Tower		
Total Suspended Particulate (d)	(Lbs/Hr)	2.74
	(Tons/Yr)	12.02
PM-10 (e)	(Lbs/Hr)	1.37
	(Tons/Yr)	5.99
PM2.5 (e)	(Lbs/Hr)	0.005
	(Tons/Yr)	0.024
Emission Rate - Per Cell		
Total Suspended Particulate	(Lbs/Hr)	0.20
	(Tons/Yr)	0.86
PM-10	(Lbs/Hr)	0.0976
	(Tons/Yr)	0.428
PM2.5	(Lbs/Hr)	0.00038
	(Tons/Yr)	0.0017

Notes:
(a) Design Water Circulation Rate, Gallons/Minute (GPM)
(b) Design Total Liquid Drift, Percent (%) [vendor guarantee]
(c) Estimated 5000 ppmw TDS in circulating water [from Alabama Power, based on previous projects]
(d) Based on USEPA AP-42 Section 13.4 Wet Cooling Towers,
Table 13.4-1 dated 1/95. Modified to Cooling Tower Design
Lbs/Hr = (Water Circulation Rate,GPM)*60*(Drift,%) / 100 *
(8.3453 Lbs/Gal) * (TDS, Lbs PM/1,000,000 Lbs Water)
Tons/Yr = (Lbs/Hr) * (8,760 Hrs/Yr) / (2,000 Lbs/Ton)
(e) Droplet size distribution from "Calculating TSP, PM-10, and PM-2.5 from Cooling Towers", New Mexico Environment Department Air Quality Bureau, September 2013

Table D-12
Emergency Diesel Generator Emissions
Annual and Maximum Hourly Criteria Pollutant Emission Rates

Emission Source:		Emergency Generators
Source Type:		Diesel Generator
Engine Power	bhp:	2010.7
	kw:	1,500
Maximum Fuel Usage (gal/hr)		126.6
Heat Input (mmBtu/hr):		17.471
Fuel consumption (Btu/hphr)		8,689
Number of Units:		2
Fuel Oil Heating Value (BTU/gal)		138,000
Sulfur Content of Fuel (wt. %) (a):		0.0015
Operating Hours per Year:		500

	Emission Factor		
		Hourly (g)	**Annual (h)**
	(g/hp-hr)	**(Lbs/Hr)**	**(Tons/Year)**
Nitrogen Oxides (a)	4.8	21.28	10.64
Carbon Monoxide (a)	2.6	11.53	5.76
TOC (a)	4.8	21.28	10.64
Sulfur Oxides (b)	0.0055	0.024	0.012
H_2SO_4 (c)	0.0004	0.002	0.001
TSP (a)	0.15	0.66	0.33
PM-10 (d)	0.14	0.61	0.31
PM2.5 (d)	0.13	0.60	0.30
CO_2e (e,f)	645	2,858	1,429

Notes:
(a) Emission factors (g/hp-hr) are the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines
(b) SO_2 emission factor from USEPA AP-42, Section 3.4, Table 3.4-1, dated October 1996, 100% conversion of fuel sulfur to SO_2
(c) Assumes 5% conversion of SO_2 to SO_3 (per AP-42 Section 1.3.3.2, September 1998)
(d) Emission factors for PM10 and PM2.5 are based on speciation in AP-42 Table 3.4-2, adjusted to conform to 40 CFR 60 Subpart IIII TSP limit
(e) Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2 (amended 12/9/2016)
(f) Global Warming Potentials for GHGs are from Federal Register Vol. 78, No. 230, November 29, 2013.
(g) Hourly Emission Rate (Lbs/Hr) = (Emission Factor, g/hp-hr) * (Engine Power, hp) * (1 lb / 453.6 g)
(h) Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

Table D-13
Emergency Generator Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates

Compound Categories	Emission Factor		Emission Est. Method	Emission Rate (2 generators)		
	Value	Units		Max Hourly (lb/hr)	Max Daily (lb/day)	Annual (tpy)
Organic Compounds:						
Acetaldehyde	2.52E-05	lb/MMBtu	1	8.81E-04	2.11E-02	2.20E-04
Acrolein	7.88E-06	lb/MMBtu	1	2.75E-04	6.61E-03	6.88E-05
Benzene	7.76E-04	lb/MMBtu	1	2.71E-02	6.51E-01	6.78E-03
Formaldehyde	7.89E-05	lb/MMBtu	1	2.76E-03	6.62E-02	6.89E-04
Toluene	2.81E-04	lb/MMBtu	1	9.82E-03	2.36E-01	2.45E-03
Xylenes	1.93E-04	lb/MMBtu	1	6.74E-03	1.62E-01	1.69E-03
Polycyclic Organic Matter:						
Acenaphthene	4.68E-06	lb/MMBtu	2	1.64E-04	3.92E-03	4.09E-05
Acenaphthylene	9.23E-06	lb/MMBtu	2	3.23E-04	7.74E-03	8.06E-05
Anthracene	1.26E-06	lb/MMBtu	2	4.40E-05	1.06E-03	1.10E-05
Benz(a)anthracene	6.22E-07	lb/MMBtu	2	2.17E-05	5.22E-04	5.43E-06
Benzo(b)fluoranthene	1.11E-06	lb/MMBtu	2	3.88E-05	9.31E-04	9.70E-06
Benzo(k)fluoranthene	2.18E-07	lb/MMBtu	2	7.62E-06	1.83E-04	1.90E-06
Benzo(g,h,i)perylene	5.56E-07	lb/MMBtu	2	1.94E-05	4.66E-04	4.86E-06
Benzo(a)pyrene	2.57E-07	lb/MMBtu	2	8.98E-06	2.16E-04	2.24E-06
Chrysene	1.53E-06	lb/MMBtu	2	5.35E-05	1.28E-03	1.34E-05
Dibenzo(a,h)anthracene	3.46E-07	lb/MMBtu	2	1.21E-05	2.90E-04	3.02E-06
Fluoranthene	4.03E-06	lb/MMBtu	2	1.41E-04	3.38E-03	3.52E-05
Fluorene	1.28E-05	lb/MMBtu	2	4.47E-04	1.07E-02	1.12E-04
Indo(1,2,3-cd)pyrene	4.14E-07	lb/MMBtu	2	1.45E-05	3.47E-04	3.62E-06
Naphthalene	1.30E-04	lb/MMBtu	2	4.54E-03	1.09E-01	1.14E-03
Phenanthrene	4.08E-05	lb/MMBtu	2	1.43E-03	3.42E-02	3.56E-04
Pyrene	3.71E-06	lb/MMBtu	2	1.30E-04	3.11E-03	3.24E-05

1 - AP-42 Table 3.4-3 (10/96) Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines

2 - AP-42 Table 3.4-4 (10/96) PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines

Table D-14
Diesel Fire-Water Pump Engine Emissions
Annual and Maximum Hourly Emission Rates

Emission Source:		Emergency Fire-Water Pump Engine
Source Type:		Diesel Fueled IC Reciprocating Engines
Engine Power	bhp:	316
	kw:	236
Maximum Fuel Usage (gal/hr)		15.0
Heat Input (mmBtu/hr):		2.070
Fuel consumption (Btu/hphr)		6,543
Number of Units:		1
Fuel Oil Heating Value (BTU/gal)		138,000
Sulfur Content of Fuel (wt. %) (a):		0.0015
Operating Hours per Year:		500

Compound	Emission Rates (total of units)		
	(g/hp-hr)	(Lbs/Hr/unit)	(Tons/Year total)
Nitrogen Oxides (a)	3.00	2.09	0.52
Carbon Monoxide (a)	2.60	1.81	0.45
TOC (a)	3.00	2.09	0.52
Sulfur Oxides (b)		0.004	0.0010
H2SO4 (c)		0.000	0.00
TSP (a)		0.10	0.026
PM-10 (d)		0.10	0.024
PM2.5 (d)		0.09	0.023
CO_2e (e,f)		339	85

Notes:

(a) Emission factors (g/hp-hr) are the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Fire Pump Engines

(b) SO_2 emission factor from USEPA AP-42, Section 3.4, Table 3.4-1, dated October 1996, 100% conversion of fuel sulfur to SO2

(c) Assumes 5% conversion of SO_2 to SO_3 (per AP-42 Section 1.3.3.2, September 1998)

(d) Emission factors for PM10 and PM2.5 are based on speciation in AP-42 Table 3.4-2, adjusted to conform to 40 CFR 60 Subpart IIII TSP limit

(e) Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting", Tables C-1 and C-2 (amended 12/9/2016)

(f) Global Warming Potentials for GHGs are from Federal Register Vol.

(g) Hourly Emission Rate (Lbs/Hr) = (Emission Factor, g/hp-hr) * (Engine Power, hp) * (1 lb / 453.6 g)

(h) Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

Table D-15
Diesel Firewater Pump Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates

Compound Categories	Emission Factor		Emission Est. Method	Emission Rate		
	Value	Units		Max Hourly (lb/hr)	Max Daily (lb/day)	Annual (tpy)
Organic Compounds:						
Acetaldehyde	7.67E-04	lb/MMBtu	1	1.59E-03	3.81E-02	3.97E-04
Acrolein	9.25E-05	lb/MMBtu	1	1.91E-04	4.60E-03	4.79E-05
Benzene	9.33E-04	lb/MMBtu	1	1.93E-03	4.64E-02	4.83E-04
Butadiene, 1,3-	3.91E-05	lb/MMBtu	1	8.09E-05	1.94E-03	2.02E-05
Formaldehyde	1.18E-03	lb/MMBtu	1	2.44E-03	5.86E-02	6.11E-04
Toluene	4.09E-04	lb/MMBtu	1	8.47E-04	2.03E-02	2.12E-04
Xylenes	2.85E-04	lb/MMBtu	1	5.90E-04	1.42E-02	1.47E-04
Polycyclic Organic Matter:						
Acenaphthene	1.42E-06	lb/MMBtu	1	2.94E-06	7.05E-05	7.35E-07
Acenaphthylene	5.06E-06	lb/MMBtu	1	1.05E-05	2.51E-04	2.62E-06
Anthracene	1.87E-06	lb/MMBtu	1	3.87E-06	9.29E-05	9.68E-07
Benz(a)anthracene	1.68E-06	lb/MMBtu	1	3.48E-06	8.35E-05	8.69E-07
Benzo(b)fluoranthene	9.91E-08	lb/MMBtu	1	2.05E-07	4.92E-06	5.13E-08
Benzo(k)fluoranthene	1.55E-07	lb/MMBtu	1	3.21E-07	7.70E-06	8.02E-08
Benzo(g,h,i)perylene	4.89E-07	lb/MMBtu	1	1.01E-06	2.43E-05	2.53E-07
Benzo(a)pyrene	1.88E-07	lb/MMBtu	1	3.89E-07	9.34E-06	9.73E-08
Chrysene	3.53E-07	lb/MMBtu	1	7.31E-07	1.75E-05	1.83E-07
Dibenzo(a,h)anthracene	5.83E-07	lb/MMBtu	1	1.21E-06	2.90E-05	3.02E-07
Fluoranthene	7.61E-06	lb/MMBtu	1	1.58E-05	3.78E-04	3.94E-06
Fluorene	2.92E-05	lb/MMBtu	1	6.04E-05	1.45E-03	1.51E-05
Indo(1,2,3-cd)pyrene	3.75E-07	lb/MMBtu	1	7.76E-07	1.86E-05	1.94E-07
Naphthalene	8.48E-05	lb/MMBtu	1	1.76E-04	4.21E-03	4.39E-05
Phenanthrene	2.94E-05	lb/MMBtu	1	6.09E-05	1.46E-03	1.52E-05
Pyrene	4.78E-06	lb/MMBtu	1	9.89E-06	2.37E-04	2.47E-06

1 - AP-42 Table 3.3-2 (10/96) Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines

Table D-16

Annual HAP Emissions (ton/yr) - All Units - Pre Upgrade Configuration

Pollutant	Aux Boiler ton/yr	FWP ton/yr	Emergency Generator ton/yr	CTG/HRSG ton/yr	Total All Units ton/yr
Metal Compounds:					
Arsenic	7.77E-05			4.10E-03	8.28E-03
Beryllium	4.66E-06			2.46E-04	4.97E-04
Cadmium	4.27E-04			2.25E-02	4.55E-02
Chromium (total)	5.44E-04			2.87E-02	5.79E-02
Cobalt	3.26E-05			1.72E-03	3.48E-03
Lead	1.94E-04			1.02E-02	2.07E-02
Manganese	1.48E-04			7.79E-03	1.57E-02
Mercury	1.01E-04			5.33E-03	1.08E-02
Nickel	8.16E-04			4.30E-02	8.69E-02
Selenium	9.33E-06			4.92E-04	9.93E-04
Organic Compounds:					
Acetaldehyde		3.97E-04	1.10E-04	8.36E-01	1.67E+00
Acrolein		4.79E-05	3.44E-05	1.34E-01	2.68E-01
Benzene	8.16E-04	4.83E-04	3.39E-03	2.51E-01	5.10E-01
1,3-Butadiene		2.02E-05			2.02E-05
Dichlorobenzene	4.66E-04				4.66E-04
Ethylbenzene				6.69E-01	1.34E+00
Formaldehyde	2.91E-02	6.11E-04	3.45E-04	4.74E+00	9.51E+00
Hexane	7.00E-01				7.00E-01
Toluene	1.32E-03	2.12E-04	1.23E-03	2.72E+00	5.44E+00
Xylene		1.47E-04	8.43E-04	1.34E+00	2.68E+00
Polycyclic Organic Matter:					
Acenaphthene	7.00E-07	7.35E-07	2.04E-05		4.23E-05
Acenaphthylene	7.00E-07	2.62E-06	4.03E-05		8.39E-05
Anthracene	9.33E-07	9.68E-07	5.37E-06		1.26E-05
Benz(a)anthracene	7.00E-07	8.69E-07	2.72E-06		7.00E-06
Benzo(a)pyrene	4.66E-07	9.73E-08	1.12E-06		2.81E-06
Benzo(b)flouoranthene	7.00E-07	5.13E-08	4.85E-06		1.04E-05
Benzo(g,h,I)perylene	4.66E-07	2.53E-07	2.43E-06		5.58E-06
Benzo(k)fluoranthene	7.00E-07	8.02E-08	9.52E-07		2.68E-06
Chrysene	7.00E-07	1.83E-07	6.68E-06		1.42E-05
Dibenzo(a,h)anthracene	4.66E-07	3.02E-07	1.51E-06		3.79E-06
Dimethylbenz(a)Anthracene, 7,12-	6.22E-06				6.22E-06
Fluoranthene	1.17E-06	3.94E-06	1.76E-05		4.03E-05
Fluorene	1.09E-06	1.51E-05	5.59E-05		1.28E-04
Indeno(1,2,3-cd)pyrene	7.00E-07	1.94E-07	1.81E-06		4.51E-06
Methylchloanthrene, 3-	7.00E-07				7.00E-07
Methylnaphthalene, 2-	9.33E-06				9.33E-06
Naphthalene	2.37E-04	4.39E-05	5.68E-04	2.72E-02	5.58E-02
PAHs				4.60E-02	9.20E-02
Phenanathrene	6.61E-06	1.52E-05	1.78E-04		3.78E-04
Pyrene	1.94E-06	2.47E-06	1.62E-05		3.68E-05

Total Project §112 HAPs (tpy)	**22.52**
Maximum Single §112 HAP (tpy)	**9.51**

Table D-17

Annual HAP Emissions (tons/yr) - All Units - Post Upgrade Configuration

Pollutant	Aux Boiler ton/yr	FWP ton/yr	Emergency Generator ton/yr	CTG/HRSG ton/yr	Total - All Units ton/yr
Metal Compounds:					
Arsenic	7.77E-05			4.21E-03	8.50E-03
Beryllium	4.66E-06			2.53E-04	5.10E-04
Cadmium	4.27E-04			2.32E-02	4.68E-02
Chromium (total)	5.44E-04			2.95E-02	5.95E-02
Cobalt	3.26E-05			1.77E-03	3.57E-03
Lead	1.94E-04			1.05E-02	2.13E-02
Manganese	1.48E-04			8.00E-03	1.62E-02
Mercury	1.01E-04			5.48E-03	1.11E-02
Nickel	8.16E-04			4.42E-02	8.93E-02
Selenium	9.33E-06			5.05E-04	1.02E-03
Organic Compounds:					
Acetaldehyde		3.97E-04	1.10E-04	8.59E-01	1.72E+00
Acrolein		4.79E-05	3.44E-05	1.37E-01	2.75E-01
Benzene	8.16E-04	4.83E-04	3.39E-03	2.58E-01	5.24E-01
1,3-Butadiene		2.02E-05			2.02E-05
Dichlorobenzene	4.66E-04				4.66E-04
Ethylbenzene				6.87E-01	1.37E+00
Formaldehyde	2.91E-02	6.11E-04	3.45E-04	4.95E+00	9.92E+00
Hexane	7.00E-01				7.00E-01
Toluene	1.32E-03	2.12E-04	1.23E-03	2.79E+00	5.59E+00
Xylene		1.47E-04	8.43E-04	1.37E+00	2.75E+00
Polycyclic Organic Matter:					
Acenaphthene	7.00E-07	7.35E-07	2.04E-05		4.23E-05
Acenaphthylene	7.00E-07	2.62E-06	4.03E-05		8.39E-05
Anthracene	9.33E-07	9.68E-07	5.50E-06		1.29E-05
Benz(a)anthracene	7.00E-07	8.69E-07	2.72E-06		7.00E-06
Benzo(a)pyrene	4.66E-07	9.73E-08	1.12E-06		2.81E-06
Benzo(b)flouoranthene	7.00E-07	5.13E-08	4.85E-06		1.04E-05
Benzo(g,h,I)perylene	4.66E-07	2.53E-07	2.43E-06		5.58E-06
Benzo(k)fluoranthene	7.00E-07	8.02E-08	9.52E-07		2.68E-06
Chrysene	7.00E-07	1.83E-07	6.68E-06		1.42E-05
Dibenzo(a,h)anthracene	4.66E-07	3.02E-07	1.51E-06		3.79E-06
Dimethylbenz(a)Anthracene, 7,12-	6.22E-06				6.22E-06
Fluoranthene	1.17E-06	3.94E-06	1.76E-05		4.03E-05
Fluorene	1.09E-06	1.51E-05	5.59E-05		1.28E-04
Indeno(1,2,3-cd)pyrene	7.00E-07	1.94E-07	1.81E-06		4.51E-06
Methylchloanthrene, 3-	7.00E-07				7.00E-07
Methylnaphthalene, 2-	9.33E-06				9.33E-06
Naphthalene	2.37E-04	4.39E-05	5.68E-04	2.79E-02	5.73E-02
PAHs				4.73E-02	9.45E-02
Phenanathrene	6.61E-06	1.52E-05	1.78E-04		3.78E-04
Pyrene	1.94E-06	2.47E-06	1.62E-05		3.68E-05

Total Project §112 HAPs (tpy)	**23.27**
Maximum Single §112 HAP (tpy)	**9.92**

Appendix E

Search Results from EPA's RACT/BACT/LAER Clearinghouse

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Combined-Cycle Combustion Turbine	3864	mmBtu/hr	Selective Catalytic Reduction (SCR) and low-NOx technology (dry low-NOx combustion technology)	2	PPMV
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Dry-Low NOx Burners, SCR	2	PPM
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr	SCR	2	PPM
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Combined Cycle Combustion Turbines	3474	mmBtu/hr	Selective catalytic reduction (SCR) and low-NOx combustion technology (dry low-NOx combustion technology for natural gas; water injection for ULSD)	2	PPM
*MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Good combustion practices, DLN burners and SCR.	2	PPM
*FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1-on-1 combined cycle unit (GE 7HA)	3266.9	MMBtu/hour	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPM
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPM
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPM
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	SCR with DLNB (Selective catalytic reduction with Dry Low NOx burners).	2	PPM
*MI-0431	INDECK NILES LLC	MI	6/26/2018	FGCTGHRSG (2 Combined Cycle CTG with HRSGs)	3421	MMBTU/H	SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners)	2	PPM
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	SCR and Dry Low NOx burners	2	PPM
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Dry-Low NOx Burners, SCR	2	PPM
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	SCR	2	PPM
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	SCR	2	PPM
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Selective Catalytic Reduction (SCR) and Dry Low NOx burners	2	PPM
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Dry Low NOx combustion technology, SCR at all steady state operating loads, good combustion and operating practices	2	PPM
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX	2	PPM
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Selective Catalytic Reduction System and Dry Low NOx	2	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	SCR	2	PPM
TN-0162	JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339	MMBtu/hr	Good combustion design and practices, selective catalytic reduction (SCR)	2	PPM
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	Selective Catalytic Reduction	2	PPM
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbine	Selective catalytic reduction; dry low-NOx; and wet injection	2	PPM
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	Selective Catalytic Reduction	2	PPM
*PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large combustion turbine	0		SCR, DLN, and good combustion practice	2	PPM
*PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Dry low-NOx burners, SCR, exclusive natural gas	2	PPM
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	SCR	2	PPM
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	SCR	2	PPM
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPM
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Selective Catalytic Reduction	2	PPM
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	Selective Catalytic Reduction	2	PPM
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	DLN burner, SCR, good engineering practice	2	PPM
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine without Duct Burner	0		DLN burners, SCR, good engineering practice	2	PPM
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) â€“ natural gas	210	MW	Selective Catalytic Reduction	2	PPM
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	SCR, Dry Lo-NOx combustor, good combustion practices and low sulfur fuels	2	PPM
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	SCR and oxidation catalyst	2	PPM
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	Selective Catalytic Reduction	2	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	Selective Catalytic Reduction	2	PPM
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	SCR & Dry Low-NOx Burners	2	PPM
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	Selective Catalytic Reduction	2	PPM
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION	2	PPM
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	Combined cycle natural gas turbines	225	MW	DLN, SCR	2	PPM
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Selective Catalytic Reduction System (SCR) and use of natural gas a clean burning fuel	2	PPM
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Selective Catalytic reduction (SCR) and use of natural gas a clean burning fuel	2	PPM
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	Selective Catalytic Reduction	2	PPM
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPM
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	Low-NOx burners and SCR	2	PPM
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr	SCR, Low-NOx burner	2	PPM
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN , USE OF PIPELINE QUALITY NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2	PPM
*TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Selective catalytic reduction	2	PPM
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine -Siemens turbine without Duct Burner	33691	MMCF/YR	Selective Catalytic Reduction and Dry Low NOx	2	PPM
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Selective Catalytic Reduction System (SCR)	2	PPM
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction Systems(SCR) and Dry Low NOx	2	PPM
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction System (SCR) and Dry Low NOx	2	PPM
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Utilize dry low-NOx burners when combusting natural gas; Utilize water injection when combusting ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	SCR	2	PPM
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Dry Low NOx Combustors & Selective Catalytic Reduction	2	PPM
*TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	selective catalytic reduction	2	PPM
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Dry Low NOx burners (DLN) and Selective Catalytic Reduction (SCR) system.	2	PPM
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Dry low NOx burner (DLN) and selective catalytic reduction system (SCR).	2	PPM
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW	SCR	2	PPM
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG	0		Dry low NOx combustion technology and selective catalytic reduction.	2	PPM
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	Dry Low-NOx burners with SCR.	2	PPM
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	DRY LOW-NOx BURNER WITH SCR.	2	PPM
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Dry low NOx (DLN) burner and selective catalytic reduction (SCR) system.	2	PPM
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Dry low NOx (DLN) burners and selective catalytic reduction (SCR) system.	2	PPM
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	SCR	2	PPM
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	SCR	2	PPM
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Selective catalytic reduction and ultra low NOx burners.	2	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	Selective Catalytic Reduction	2	PPM
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0		SCR	2	PPM
DE-0024	GARRISON ENERGY CENTER	DE	1/30/2013	Unit 1	2260	million BTUs	Low NOx Combustors, Selective Catalytic Reduction	2	PPM
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX BURNERS	2	PPM
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Selelctive catalytic reduction (SCR) system	2	PPM
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Selective Catalytic Reduction (SCR) System and use of natural gas a clean burning fuel	2	PPM
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Selective catalytic reduction	2	PPM
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	SCR/DLN	2	PPM
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Dry low-NOx (DLN) combustor and selective catalytic reduction (SCR)	2	PPM
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	Selective Catalytic Reduction	2	PPM
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	Selective catalytic reduction	2	PPM
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	Low NOx burners and Selective Catalytic Reduction System	2	PPM
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	DLN combustion system with SCR on each of the two combustion turbines and use of only natural gas as fuel.	2	PPM
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	154	MW	DRY LOW NOX (DLN) COMBUSTORS, SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPM
TX-0600	THOMAS C. FERGUSON POWER PLANT	TX	9/1/2011	Natural gas-fired turbines	390	MW	Dry low NOx burners and Selective Catalytic Reduction	2	PPM
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	180	MW	SCR, DRY LOW NOX COMBUSTORS	2	PPM
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, WITH DUCT BURNING)	180	MW	SCR, DRY LOW NOX COMBUSTORS	2	PPM
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	180	MW	SCR, DRY LOW NOX COMBUSTORS	2	PPM
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, WITH DUCT BURNING)	180	MW	SCR, DRY LOW NOX COMBUSTORS	2	PPM
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (NORMAL OPERATION)	172	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OR-0048	CARTY PLANT	OR	12/29/2010	COMBINED CYCLE NATURAL GAS-FIRED ELECTRIC GENERATING UNIT	2866	MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPM
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VA	12/17/2010	COMBINED CYCLE TURBINE & DUCT BURNER, 3	2996	MMBTU/H	Two-stage, lean pre-mix dry low-NOx combustor and a selective catalytic reduction (SCR) control system using ammonia injection.	2	PPM
TX-0590	KING POWER STATION	TX	8/5/2010	Turbine	1350	MW	DLN burners and SCR	2	PPM
ID-0018	LANGLEY GULCH POWER PLANT	ID	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2375.28	MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR), DRY LOW NOX (DLN), GOOD COMBUSTION PRACTICES (GCP)	2	PPM
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	154	MW	SCR	2	PPM
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NORMAL OPERATION, WITH DUCT BURNING)	154	MW	SCR	2	PPM
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	154	MW	SCR	2	PPM
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NORMAL OPERATION, WITH DUCT BURNING)	154	MW	SCR	2	PPM
TX-0548	MADISON BELL ENERGY CENTER	TX	8/18/2009	ELECTRICITY GENERATION	275	MW	SELECTIVE CATALYTIC REDUCTION	2	PPM
CA-1177	OTAY MESA ENERGY CENTER LLC	CA	7/22/2009	Gas turbine combined cycle	171.7	MW	SCR	2	PPM
TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	TX	6/22/2009	ELECTRICITY GENERATION	250	MW	SELECTIVE CATALYTIC REDUCTION	2	PPM
TX-0546	PATTILLO BRANCH POWER PLANT	TX	6/17/2009	ELECTRICITY GENERATION	350	MW	SELECTIVE CATALYTIC REDUCTION	2	PPM
NJ-0074	WEST DEPTFORD ENERGY	NJ	5/6/2009	TURBINE, COMBINED CYCLE	17298	MMFT3/YR	SELECTIVE CATALYTIC REDUCTION (SCR) AND WATER INJECTION	2	PPM
CA-1178	APPLIED ENERGY LLC	CA	3/20/2009	Gas turbine combined cycle	0		SCR	2	PPM
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1882	MMBTU/H	SCR AND DRY LOW-NOX	2	PPM
FL-0304	CANE ISLAND POWER PARK	FL	9/8/2008	300 MW COMBINED CYCLE COMBUSTION TURBINE	1860	MMBTU/H	SCR	2	PPM
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	2333	MMBTU/H	DRY LOW NOX SELECTIVE CATALYST REDUCTION	2	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CT-0151	KLEEN ENERGY SYSTEMS, LLC	CT	2/25/2008	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	2.1	MMCF/H	LOW NOX BURNER AND SELECTIVE CATALYTIC REDUCTION	2	PPM
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations; Good Combustion Practices during Startup/Shutdown operations.	2	PPM
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations, and good combustion practices during startup/shutdown operations.	2	PPM
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Low NOx Burners, SCR, and Good Combustion Practices	2.5	PPM
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H	Selective Catalytic Reduction	2.5	PPM
GA-0138	LIVE OAKS POWER PLANT	GA	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	600	MW	DRY LOW NOx BURNERS, SELECTIVE CATALYTIC REDUCTION	2.5	PPM
CA-1209	HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATORS (NORMAL OPERATION)	190	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)	2.5	PPM
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCCT (Combined cycle CTG with unfired HRSG)	1934.7	MMBTU/H	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	3	PPM
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	3	PPM
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	SCR with DLNB (selective catalytic reduction with dry low NOx burners).	3	PPM
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat input, each CTG	Low NOx burners and selective catalytic reduction.	3	PPM
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Dry Low NOx burners and Selective Catalytic Reduction	3	PPM
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Dry Low NOx burners and Selective Catalytic Reduction	3	PPM
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	SCR	3	PPM
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	SCR	3	PPM
CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	7/22/2010	Four combined cycle combution turbines	373	MMBTU/H	Dry Low NOx (DLN) Combustor and Selective Catalytic Reduction (SCR)	3	PPM
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	TWO COMBINED CYCLE GAS TURBINES	2110	MMBTU/H	LOW NOX TURBINES, DUCT BURNERS COMBINED WITH SCR	4	PPM
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	SCR with DLNB (selective catalytic reduction with dry low NOx burners)	4	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IL-0112	NELSON ENERGY CENTER	IL	12/28/2010	Electric Generation Facility	220	MW each	SCR and Low-NOx Combustors	4.5	PPM
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	Combustion Turbine with SCR/HRSG	607.1	MMBTU/hr	Selective Catalytic Reduction (SCR) and Water/Steam Injection	5	PPM
TX-0698	BAYPORT COMPLEX	TX	9/5/2013	(4) cogeneration turbines	90	MW	DLN and Closed Loop Emissions Controls (CLEC)	5	PPM
AK-0071	INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	GE LM6000PF-25 Turbines (4)	59900	hp ISO	Selective Catalytic Reduction and Dry Low NOx Combustion	5	PPM
AK-0073	INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	Fuel Combustion	59900	HP	Turbines EU IDs 5 through 8 shall be equipped with Selective Catalytic Reduction and Dry Low NOx (SCR and DLN) combustors. SCR is a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen dioxide (NO2) in the turbine exhaust stream to molecular nitrogen, water, and oxygen. This process is accomplished by using ammonia (NH3) as a reducing agent, and is injected into the flue gas upstream of the catalyst bed. By lowering the activation energy of the NOx decomposition removal efficiency of 80 to 90 percent are achievable. DLN combustors utilize multistage premix combustors where the air and fuel is mixed at a lean fuel to air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture, both resulting in greatly reduced NOx formation rates. DLN can reduce emissions by about 60%	5	PPM
LA-0136	PLAQUEMINE COGENERATION FACILITY	LA	7/23/2008	(4) GAS TURBINES/DUCT BURNERS	2876	MMBTU/H	DRY LOW NOX BURNERS, SELECTIVE CATALYTIC REDUCTION	5	PPM
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB: 4 nat gas fired CTG with DB for HRSG: Startup/shutdown events	2587	MMBTU/H design heat input, each	Low NOx burners and selective catalytic reduction.	7	PPM
MI-0402	SUMPTER POWER PLANT	MI	11/17/2011	Combined cycle combustion turbine w/ HRSG	130	MW electrical output	Low NOx burners	9	PPM
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H	SCR	9	PPM
CO-0076	PUEBLO AIRPORT GENERATING STATION	CO	12/11/2014	Four combined cycle combution turbines	373	MMBTU/H each	SCR and dry low NOx burners	21	PPM
MI-0439	JACKSON GENERATING STATION	MI	4/2/2019	FGLMDB1-6 (6 combined cycle natural gas fired CTG each equipped with a HRSG)	420	MW	Steam injection, good combustion practices and only combust natural gas.	25	PPM

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG--Startup/Shutdown (2 combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H; EACH	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	76	PPM
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG--Startup/Shutdown	2237	MMBTU/H each	Dry low NOx (DLN) burner and selective catalytic reduction (SCR)	80	PPM
OK-0169	PSO COMANCHE POWER STATION	OK	10/8/2015	COMBINED CYCLE COMBUSTION TURBINE	1250	MMBTUH	Use of Dry Low NOx Burners	144	PPM
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	SCN-4 HOT STARTUP CTG-1 SCN-8 HOT STARTUP CTG-2	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURER'S RECOMMENDED PROCEDURES.	182	PPM
*MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3--Startup/Shutdown Operations	1230	MW	Good combustion practices, DLN burners and SCR.		
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)--Startup & Shutdown	0		SCR with DLNB (Selective catalytic reduction with dry low NOx burners).		
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	COMBINED CYCLE TURBINE MSS REDUCED LOAD	0		minimizing duration of startup / shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limits on the MAERT		
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCCT (Startup/Shutdown)	1934.7	MMBTU/H	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).		
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner - firing NG blend with ethane	0				
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner - firing NG blend with ethane	0				
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	286	MW	DRY LOW-NOX COMBUSTOR DESIGN, GOOD COMBUSTION PRACTICES AND SELECTIVE CATALYTIC REDUCTION (SCR)		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)		

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	235	MW	DRY LOW-NOX COMBUSTOR DESIGN, GOOD COMBUSTION PRACTICES AND SELECTIVE CATALYTIC REDUCTION		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: Startup & Shutdown	647	MMBTU/H for each CTGHRSG	SCR with DLNB (selective catalytic reduction with dry low NOx burners).		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Startup/Shutdown	2147	MMBTU/H	Dry low NOx burners (DLN) and selective catalytic reduction (SCR) system.		
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	VA	4/30/2013	Large combustion turbines (25MW) CCT1 and CCT2	2.23	MMBTU/H	Selective Catalytic Reduction (SCR), with ammonia injection and dry low NOx combusion.		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES - START UP/SHUTDOWN CYCLE	2300	MMBTU/H			
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (STARTUP PERIODS)	154	MW	DRY LOW NOX (DLN) COMBUSTORS, SELECTIVE CATALYTIC REDUCTION (SCR)		
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (SHUTDOWN PERIODS)	110	MMBTU/H	DRY LOW NOX (DLN) COMBUSTORS, SELECTIVE CATALYTIC REDUCTION (SCR)		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (STARTUP & SHUTDOWN PERIODS)	180	MW	SCR, DRY LOW NOX COMBUSTORS		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (STARTUP & SHUTDOWN PERIODS)	180	MW	SCR, DRY LOW NOX COMBUSTORS		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (WARM STARTUP PERIODS)	172	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (HOT STARTUP PERIODS)	172	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (SHUTDOWN PERIODS)	172	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (COLD STARTUP PERIODS)	172	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (COLD STARTUP PERIODS)	154	MW	SCR		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (WARM & HOT STARTUP PERIODS)	154	MW	SCR		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (SHUTDOWN PERIODS)	154	MW	SCR		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (COLD STARTUP PERIODS)	154	MW	SCR		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (WARM & HOT STARTUP PERIODS)	154	MW	SCR		

TABLE E-1
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (SHUTDOWN PERIODS)	154	MW	SCR		
CA-1209	HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATOR (STARTUP PERIODS)	190	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)		
CA-1209	HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATOR (SHUTDOWN PERIODS)	190	MW	DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR)		
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1882	MMBTU/H	DRY LOW-NOX		

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Oxidation Catalyst	0.9	PPMV
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	0.9	PPMV
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	0.9	PPMV
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation Catalyst and Use of Natural gas a clean burning fuel	0.9	PPMV
CT-0151	KLEEN ENERGY SYSTEMS, LLC	CT	2/25/2008	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	2.1	MMCF/H	CO CATLYST	0.9	PPMV
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1.5	PPMV
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITHOUT DUCT FIRING	270	MW	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, USE OF AN OXIDATION CATALYST AND EFFICIENT CT DESIGN	1.5	PPMV
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Oxidation catalyst; good combustion practices.	1.5	PPMV
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	Three Mitsubishi M501 GAC Turbines (3,442 mmBtu/hr each)	0	s	Oxidation catalyst and good combustion practices including the minimization of startup and shutdown emissions	1.5	PPMV
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	154	MW	OXIDATION CATALYST SYSTEM	1.5	PPMV
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	180	MW	OXIDATION CATALYST SYSTEM	1.5	PPMV
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	180	MW	OXIDATION CATALYST SYSTEM	1.5	PPMV
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Oxidation Catalyst	1.6	PPMV
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	GA	1/7/2008	COMBINED CYCLE COMBUSTION TURBINE	254	MW	OXIDATION CATALYST	1.8	PPMV
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Combined-Cycle Combustion Turbine	3864	mmBtu/hr	Oxidation catalyst	2	PPMV
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	2	PPMV
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr	Oxidation Catalyst	2	PPMV
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Combined Cycle Combustion Turbines	3474	mmBtu/hr	Oxidation catalyst	2	PPMV
*MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Oxidation catalyst technology and good combustion practices.	2	PPMV
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	OXIDATION CATALYST	2	PPMV
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	2	PPMV

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Selective Catalytic Reduction (SCR) and Dry Low NOx burners	2	PPMV
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Oxidation catalyst operated at all steady state operating loads and good combustion practices	2	PPMV
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Catalytic Oxidation and good combustion practices during normal operations, and good combustion practices during startup/shutdown operations.	2	PPMV
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Catalytic oxidation and good combustion practices during normal operations, and good combustion practices during startup/shutdown operations.	2	PPMV
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	Oxidation Catalyst and good combustion practices	2	PPMV
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	2	PPMV
TN-0162	JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339	MMBtu/hr	Good combustion design and practices, oxidation catalyst	2	PPMV
*PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Oxidation catalyst, combustion controls, exclusive natural gas	2	PPMV
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	2	PPMV
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Oxidation Catalyst	2	PPMV
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	Oxidation Catalyst	2	PPMV
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine without Duct Burner	0		Oxidation catalyst, good engineering practice	2	PPMV
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) â€“ natural gas	210	MW	Oxidation catalyst	2	PPMV
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	Oxidation catalyst and good combustion practices	2	PPMV
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Oxidation Catalyst + Combustion Controls	2	PPMV
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	2	PPMV
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	Combined cycle natural gas turbines	225	MW	OC	2	PPMV
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	oxidation catalyst	2	PPMV
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	2	PPMV

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	catalytic oxidizer	2	PPMV
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr	CO catalyst	2	PPMV
*TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Oxidation catalyst	2	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine -Siemens turbine without Duct Burner	33691	MMCF/YR	CO Oxidation Catalyst and Good Combustion Practices and use of Natural gas as a clean burning fuel	2	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Oxidation catalyst and use of only natural gas a clean burning fuel	2	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	CO Oxidation catalyst and good combustion practices and use of natural gas only as a clean burning fuel	2	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	CO Oxidation Catalyst and Good Combustion Practices and use of Natural gas as a clean burning fuel	2	PPMV
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	oxidation catalyst	2	PPMV
*TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	oxidation catalyst	2	PPMV
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW	OC	2	PPMV
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG	0		Good combustion practice and oxidation catalyst.	2	PPMV
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	Oxidation catalyst and good combustion practice.	2	PPMV
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES.	2	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	oxidation catalyst	2	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	oxidation catalyst	2	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	2	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	2	PPMV
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	CO catalyst	2	PPMV
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	Oxidation Catalyst	2	PPMV
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	oxidation catalyst	2	PPMV
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0		CO Catalyst	2	PPMV
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	OXIDATION CATALYST	2	PPMV

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Oxidation catalyst	2	PPMV
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel	2	PPMV
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Oxidation Catalyst	2	PPMV
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	Oxidation Catalyst; Good Combustion Practices	2	PPMV
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	Oxidation Catalyst, good combustion practices and use only natural gas a clean burning fuel	2	PPMV
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, WITH DUCT BURNING)	180	MW	OXIDATION CATALYST SYSTEM	2	PPMV
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, WITH DUCT BURNING)	180	MW	OXIDATION CATALYST SYSTEM	2	PPMV
TX-0590	KING POWER STATION	TX	8/5/2010	Turbine	1350	MW	good combustion practices with an oxidation catalyst	2	PPMV
ID-0018	LANGLEY GULCH POWER PLANT	ID	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2375.28	MMBTU/H	CATALYTIC OXIDATION (CATOX), DRY LOW NOX (DLN), GOOD COMBUSTION PRACTICES (GCP)	2	PPMV
GA-0138	LIVE OAKS POWER PLANT	GA	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	600	MW	GOOD COMBUSTION PRACTICES AND CATALYTIC OXIDATION	2	PPMV
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	154	MW	OXIDATION CATALYST SYSTEM	2	PPMV
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	154	MW	OXIDATION CATALYST SYSTEM	2	PPMV
TX-0546	PATTILLO BRANCH POWER PLANT	TX	6/17/2009	ELECTRICITY GENERATION	350	MW	OXIDATION CATALYST	2	PPMV
NJ-0074	WEST DEPTFORD ENERGY	NJ	5/6/2009	TURBINE, COMBINED CYCLE	17298	MMFT3/YR	CO OXIDATION CATALYST	2	PPMV
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VA	12/17/2010	COMBINED CYCLE TURBINE & DUCT BURNER, 3	2996	MMBTU/H	Oxidation catalyst and good combustion practices.	2.4	PPMV
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	CO Catalyst	3	PPMV
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B)	7146	MMBTU/H	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	3	PPMV
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (NORMAL OPERATION)	172	MW	CATALYTIC OXIDATION SYSTEM	3	PPMV
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NORMAL OPERATION, WITH DUCT BURNING)	154	MW	OXIDATION CATALYST SYSTEM	3	PPMV
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NORMAL OPERATION, WITH DUCT BURNING)	154	MW	OXIDATION CATALYST SYSTEM	3	PPMV
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.	3.3	PPMV

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMV
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMV
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCCT (Combined cycle CTG with unfired HRSG)	1934.7	MMBTU/H	Oxidation catalyst technology and good combustion practices.	4	PPMV
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Oxidation catalyst technology and good combustion practices.	4	PPMV
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	4	PPMV
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	4	PPMV
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	SCR and oxidation catalyst	4	PPMV
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	oxidation catalyst	4	PPMV
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	oxidation catalyst	4	PPMV
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	oxidation catalyst	4	PPMV
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.	4	PPMV
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat input, each CTG	Efficient combustion control plus catalytic oxidation system.	4	PPMV
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Good combustion	4	PPMV
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	good combustion	4	PPMV
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	good combustion	4	PPMV
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	Oxidation Catalyst	4	PPMV
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	Oxidation Catalyst	4	PPMV
TX-0600	THOMAS C. FERGUSON POWER PLANT	TX	9/1/2011	Natural gas-fired turbines	390	MW	Good combustion practices and oxidation catalyst	4	PPMV
CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	7/22/2010	Four combined cycle combution turbines	373	MMBTU/H	Good combustion control and catalytic oxidation	4	PPMV
CA-1209	HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATORS (NORMAL OPERATION)	190	MW	OXIDATION CATALYST SYSTEM	4	PPMV
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	2-on-1 combined cycle unit (GE 7HA)	4000	MMBtu/hr	Clean burning fuel with lean pre-mix turbines	4.3	PPMV
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbine	Clean burners that prevent CO formation	4.3	PPMV

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Oxidation Catalyst, Proper Design, Good Combustion Practices.	5	PPMV
*IL-0112	NELSON ENERGY CENTER	IL	12/28/2010	Electric Generation Facility	220	MW each		5	PPMV
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Good combustion practices burning natural gas	6	PPMV
FL-0304	CANE ISLAND POWER PARK	FL	9/8/2008	300 MW COMBINED CYCLE COMBUSTION TURBINE	1860	MMBTU/H	GOOD COMBUSTION PRACTICES	6	PPMV
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	2333	MMBTU/H	GOOD COMBUSTION	6	PPMV
*FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1-on-1 combined cycle unit (GE 7HA)	3266.9	MMBtu/hour	Clean burning fuel with good combustion practices	6.5	PPMV
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		Oxidation catalyst technology and good combustion practices.	7	PPMV
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Good combustion practices burning natural gas	8	PPMV
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1882	MMBTU/H	GOOD COMBUSTION	8	PPMV
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Catalytic oxidation system (COS)	8	PPMV
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Catalytic oxidation system	8	PPMV
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices	9	PPMV
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	TWO COMBINED CYCLE GAS TURBINES	2110	MMBTU/H	PROPER OPERATING PRACTICES	10	PPMV
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices	10.5	PPMV
TX-0727	CEDAR BAYOU ELECTRIC GENERATING STATION	TX	3/31/2015	Combined cycle turbines	187	MW/turbine	Oxidation catalysts	15	PPMV
TX-0698	BAYPORT COMPLEX	TX	9/5/2013	(4) cogeneration turbines	90	MW	DLN and Closed Loop Emissions Controls (CLEC)	15	PPMV
TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	TX	6/22/2009	ELECTRICITY GENERATION	250	MW	GOOD COMBUSTION PRATICES	15	PPMV
TX-0548	MADISON BELL ENERGY CENTER	TX	8/18/2009	ELECTRICITY GENERATION	275	MW	GOOD COMBUSTION PRACTICES	17.5	PPMV
LA-0136	PLAQUEMINE COGENERATION FACILITY	LA	7/23/2008	(4) GAS TURBINES/DUCT BURNERS	2876	MMBTU/H	GOOD COMBUSTION PRACTICES	25	PPMV
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H	CO Catalyst	25	PPMV
TX-0687	WEST PLANT AND EAST PLANT CENTRAL HEAT AND POWER	TX	10/13/2014	Two Combustion Turbine-Generators	13	MW	Good combustion practices	50	PPMV
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H	Oxidation Catalyst System	51	PPMV

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0402	SUMPTER POWER PLANT	MI	11/17/2011	Combined cycle combustion turbine w/ HRSG	130	MW electrical output		76	PPMV
OK-0169	PSO COMANCHE POWER STATION	OK	10/8/2015	COMBINED CYCLE COMBUSTION TURBINE	1250	MMBTUH	Controlled Startup and Shutdown procedures with respect to Dry Low NOx Burners.	124	PPMV
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Oxidation Catalyst	2687	PPMV
*MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3--Startup/Shutdown Operations	1230	MW	Oxidation catalyst technology and good combustion practices.		
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)--Startup & Shutdown	0		Oxidation catalyst technology and good combustion practices.		
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	COMBINED CYCLE TURBINE MSS REDUCED LOAD	0		minimizing duration of startup / shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limits on the MAERT		
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCCT (Startup/Shutdown)	1934.7	MMBTU/H	Oxidation catalyst technology and good combustion practices.		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Oxidation catalyst technology and good combustion practices.		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG--Startup/Shutdown (2 combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H; EACH	Oxidation catalyst technology and good combustion practices.		
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner - firing NG blend with ethane	0				
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner - firing NG blend with ethane	0				
*PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large combustion turbine	0		Oxidation Catalyst and good combustion practice		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		
CO-0076	PUEBLO AIRPORT GENERATING STATION	CO	12/11/2014	Four combined cycle combution turbines	373	MMBTU/H each	Catalytic Oxidation.		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	235	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	235	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	235	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	235	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: Startup & Shutdown	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Startup/Shutdown	2147	MMBTU/H	Catalytic oxidation system (COS)		
OK-0157	CHOUTEAU POWER PLANT	OK	9/5/2013	LARGE COMBUSTION TURBINES-COMBINED CYCLE & COGEN	182	MMBTU			
OK-0157	CHOUTEAU POWER PLANT	OK	9/5/2013	Turbine	178	MW	Minimize time spent in startup/shutdown.		
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB: 4 nat gas fired CTG with DB for HRSG: Startup/shutdown events	2587	MMBTU/H design heat input, each	Efficient combustion control plus catalytic oxidation system.		
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	VA	4/30/2013	Large combustion turbines (>25MW) CCT1 and CCT2	2.23	MMBTU/H	Catalytic Oxidizer		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG--Startup/Shutdown	2237	MMBTU/H each	Good combustion practices		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES - START UP/SHUTDOWN CYCLE	2300	MMBTU/H			
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (STARTUP PERIODS)	154	MW	CATALYST OXIDATION SYSTEM		
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (SHUTDOWN PERIODS)	110	MMBTU/H	OXIDATION CATALYST SYSTEM		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (STARTUP & SHUTDOWN PERIODS)	180	MW	OXIDATION CATALYST SYSTEM		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (STARTUP & SHUTDOWN PERIODS)	180	MW	OXIDATION CATALYST SYSTEM		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (WARM STARTUP PERIODS)	172	MW	CATALYTIC OXIDATION SYSTEM		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (HOT STARTUP PERIODS)	172	MW	CATALYTIC OXIDATION SYSTEM		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (SHUTDOWN PERIODS)	172	MW	CATALYTIC OXIDATION SYSTEM		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (COLD STARTUP PERIODS)	172	MW	CATALYTIC OXIDATION SYSTEM		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (WARM & HOT STARTUP PERIODS)	154	MW	OXIDATION CATALYST SYSTEM		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (SHUTDOWN PERIODS)	154	MW	OXIDATION CATALYST SYSTEM		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (COLD STARTUP PERIODS)	154	MW	OXIDATION CATALYST SYSTEM		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (WARM & HOT STARTUP PERIODS)	154	MW	OXIDATION CATALYST SYSTEM		

TABLE E-2
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (SHUTDOWN PERIODS)	154	MW	OXIDATION CATALYST SYSTEM		
CA-1209	HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATOR (STARTUP PERIODS)	190	MW	OXIDATION CATALYST SYSTEM		
CA-1209	HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATOR (SHUTDOWN PERIODS)	190	MW	OXIDATION CATALYST SYSTEM		
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1882	MMBTU/H	GOOD COMBUSTION		
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	SCN-4 HOT STARTUP CTG-1 SCN-8 HOT STARTUP CTG-2	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURERS RECOMMENDED PROCEDURES.		

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1882	MMBTU/H	GOOD COMBUSTION	0.3	PPMV
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Oxidation Catalyst	0.7	PPMV
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation catalysts and use of Natural gas a clean burning fuel	0.7	PPMV
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG	0		Good combustion practice and oxidation catalyst.	0.7	PPMV
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Oxidation catalyst; good combustion practices.	0.7	PPMV
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr	Oxidation Catalyst	1	PPMV
*MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	An oxidation catalyst and good combustion practices.	1	PPMV
FL-0364	SEMINOLE GENERATING STATION	FL	3/21/2018	2-on-1 natural gas combined-cycle unit (GE 7HA.02)	3514	MMBtu/hr	Oxidation catalyst	1	PPMV
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	2-on-1 combined cycle unit (GE 7HA)	4000	MMBtu/hr	Clean fuels	1	PPMV
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	TX	2/17/2017	Combined Cycle Cogeneration	50	MW	OXIDATION CATALYST	1	PPMV
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner NG only	0			1	PPMV
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Oxidation catalyst and good combustion practices	1	PPMV
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbine	Complete combustion minimizes VOC	1	PPMV
*PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine without duct burner	0		Oxidation catalyst, combustion controls, exclusive natural gas	1	PPMV
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	1	PPMV
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	1	PPMV
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMV

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	oxidation catalyst	1	PPMV
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMV
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1	PPMV
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMV
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	catalytic oxidizer	1	PPMV
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr		1	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine - Siemens turbine without Duct Burner	33691	MMCF/YR	Good Combustion Practices and use of Natural gas as a clean burning fuel	1	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Oxidation Catalyst and use of natural gas a clean burning fuel	1	PPMV
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Oxidation catalyst	1	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	oxidation catalyst	1	PPMV
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	Oxidation Catalyst	1	PPMV
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	OXIDIZED CATALYST	1	PPMV
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Oxidation catalyst	1	PPMV
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel	1	PPMV

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Oxidation Catalyst	1	PPMV
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	Oxidation catalyst and good combustion practices, use of natural gas a clean burning fuel	1	PPMV
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices.	1.1	PPMV
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	2333	MMBTU/H		1.2	PPMV
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT with DUCT BURNERS UNIT	0			1.4	PPMV
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Oxidation Catalyst and good combustion practices	1.4	PPMV
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	fuel Sulfur limits	1.4	PPMV
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B)	7146	MMBTU/H	GOOD COMBUSTION PRACTICES	1.4	PPMV
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Oxidation catalyst and good combustion practices	1.5	PPMV
*PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Oxidation catalyst, combustion controls, exclusive natural gas	1.5	PPMV
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	Oxidation catalyst and good engineering practice	1.5	PPMV
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine without Duct Burner	0		Oxidation catalyst, and good engineering practice	1.5	PPMV
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two combined cycle turbines with out duct burner	2291.64	MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.5	PPMV
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	Oxidation Catalyst	1.5	PPMV
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0		CO Catalyst	1.5	PPMV
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Oxidation Catalyst	1.6	PPMV

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	1.6	PPMV
TX-0590	KING POWER STATION	TX	8/5/2010	Turbine	1350	MW	DLN burners in combination with an oxidation catalyst	1.8	PPMV
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	GA	1/7/2008	COMBINED CYCLE COMBUSTION TURBINE	254	MW	OXIDATION CATALYST	1.8	PPMV
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.9	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	oxidation catalyst	1.9	PPMV
NJ-0074	WEST DEPTFORD ENERGY	NJ	5/6/2009	TURBINE, COMBINED CYCLE	17298	MMFT3/YR	CO OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1.9	PPMV
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	2	PPMV
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	Oxidation catalyst	2	PPMV
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	2	PPMV
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	Oxidation Catalyst and good combustion practices	2	PPMV
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPMV
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPMV
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Oxidation Catalyst	2	PPMV
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	oxidation catalyst	2	PPMV
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) â€“ natural gas	210	MW	Oxidation catalyst	2	PPMV
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Oxidation Catalyst & Good Combustion Practices	2	PPMV
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	oxidation catalyst	2	PPMV

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	725	MW	EXCLUSIVE USE OF NATURAL GAS, AND AN OXIDATION CATALYST	2	PPMV
*TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Oxidation catalyst, good combustion practices	2	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Oxidation catalyst and pollution prevention (use of natural gas a clean burning fuel)	2	PPMV
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	CO Oxidation Catalyst and good combustion practices and use natural gas only as a clean burning fuel	2	PPMV
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.	2	PPMV
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	CO Catalyst	2	PPMV
*TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	oxidation catalyst	2	PPMV
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Catalytic oxidation system (COS)	2	PPMV
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Catalytic oxidation system (COS)	2	PPMV
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW		2	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	2	PPMV
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	2	PPMV
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	oxidation catalyst	2	PPMV
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Good combustion	2	PPMV
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	good combustion, use of natural gas	2	PPMV

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	good combustion and natural gas as fuel	2	PPMV
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	oxidation Catalyst and Good Combustion Practices and use of Clean fuel (Natural gas)	2	PPMV
TX-0600	THOMAS C. FERGUSON POWER PLANT	TX	9/1/2011	Natural gas-fired turbines	390	MW	Natural gas, good combustion practices and oxidation catalyst	2	PPMV
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (NORMAL OPERATION)	172	MW		2	PPMV
ID-0018	LANGLEY GULCH POWER PLANT	ID	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2375.28	MMBTU/H	CATALYTIC OXIDATION (CATOX), DRY LOW NOX (DLN), GOOD COMBUSTION PRACTICES (GCP)	2	PPMV
GA-0138	LIVE OAKS POWER PLANT	GA	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	600	MW	GOOD COMBUSTION PRACTICES, CATALYTIC OXIDATION	2	PPMV
CA-1177	OTAY MESA ENERGY CENTER LLC	CA	7/22/2009	Gas turbine combined cycle	171.7	MW		2	PPMV
TX-0546	PATTILLO BRANCH POWER PLANT	TX	6/17/2009	ELECTRICITY GENERATION	350	MW	OXIDATION CATALYST	2	PPMV
CA-1178	APPLIED ENERGY LLC	CA	3/20/2009	Gas turbine combined cycle	0		Oxidation catalyst	2	PPMV
*PA-0306	TENASKA PA PARTNERS/WESTMOREL AND GEN FAC	PA	2/12/2016	Large combustion turbine	0		Ox Cat and good combustion practices	2.4	PPMV
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VA	12/17/2010	COMBINED CYCLE TURBINE & DUCT BURNER, 3	2996	MMBTU/H	Oxidation catalyst and good combustion practices.	2	PPMV
TX-0548	MADISON BELL ENERGY CENTER	TX	8/18/2009	ELECTRICITY GENERATION	275	MW	GOOD COMBUSTION PRACTICES	2.5	PPMV
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	Oxidation Catalyst	3	PPMV
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	Oxidation Catalyst	3	PPMV
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Oxidation catalyst and good combustion practices	3.5	PPMV

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMV
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMV
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	4	PPMV
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Oxidation catalyst technology and good combustion practices.	4	PPMV
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	SCR and oxidation catalyst	4	PPMV
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	oxidation catalyst	4	PPMV
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	oxidation catalyst	4	PPMV
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.	4	PPMV
*IL-0112	NELSON ENERGY CENTER	IL	12/28/2010	Electric Generation Facility	220	MW each		4	PPMV
CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	7/22/2010	Four combined cycle combution turbines	373	MMBTU/H	good combustion control and catalytic oxidation	4	PPMV
TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	TX	6/22/2009	ELECTRICITY GENERATION	250	MW	GOOD COMBUSTION PRACTICES	4	PPMV
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	TWO COMBINED CYCLE GAS TURBINES	2110	MMBTU/H	PROPER OPERATING PRACTICES	4.9	PPMV
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices	5	PPMV
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	Oxidation catalyst and good combustion practices.	5	PPMV
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES.	5	PPMV

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CT-0151	KLEEN ENERGY SYSTEMS, LLC	CT	2/25/2008	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	2.1	MMCF/H	SOME REDUCTIONS OF VOC ARE GAINED FROM CO CATALYST BUT ARE NOT GUARANTEED. EMISSION RATES DO NOT INCORPORATE THIS POTENTIAL REDUCTION.	5	PPMV
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		Oxidation catalyst technology and good combustion practices.	7	PPMV
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices	11	PPMV
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H		19	PPMV
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H	Oxidation catalyst system	27	PPMV
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Catalytic oxidation and good combustion practices for normal operations, and good combustion practices for startup/shutdown operations.	47	PPMV
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Catalytic oxidation and good combustion practices during normal operations, and good combustion practices during startup/shutdown operations.	47	PPMV
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	COMBINED CYCLE TURBINE MSS REDUCED LOAD	0		minimizing duration of startup / shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limits on the MAERT		
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner - firing NG blend with ethane	0				
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner - firing NG blend with ethane	0				
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST		

TABLE E-3
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: Startup & Shutdown	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.		
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat input, each CTG	Efficient combustion control plus catalytic oxidation system.		
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Using efficient combustion technology		
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Using efficient combustion technology		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES - START UP/SHUTDOWN CYCLE	2300	MMBTU/H			
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (WARM STARTUP PERIODS)	172	MW			
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (HOT STARTUP PERIODS)	172	MW			
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (SHUTDOWN PERIODS)	172	MW			
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (COLD STARTUP PERIODS)	172	MW			
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	SCN-4 HOT STARTUP CTG-1 SCN-8 HOT STARTUP CTG-2	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURER'S RECOMMENDED PROCEDURES.		

TABLE E-4
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER (TPM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Combined-Cycle Combustion Turbine	3864	mmBtu/hr	Good combustion practices	0.0026	LB/ MMBTU
*PA-0306	TENASKA PA PARTNERS/WESTMOREL AND GEN FAC	PA	2/12/2016	Large combustion turbine	0		Good combustion practices with the use of low ash/sulfer fuels	0.0039	LB/ MMBTU
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices	0.004	LB/ MMBTU
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Using fuel with little or no ash and sulfur content.	0.004	LB/ MMBTU
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr		0.0043	LB/ MMBTU
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	154	MW	USE PUC QUALITY NATURAL GAS	0.0048	LB/ MMBTU
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Low sulfur fuel, good combustion practicies	0.005	LB/ MMBTU
TN-0162	JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339	MMBtu/hr	Good combustion design and practices	0.005	LB/ MMBTU
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Air Filter, Use of Natural Gas, Good Combustion Practices	0.005205652	LB/ MMBTU
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0			0.0057	LB/ MMBTU
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices	0.006	LB/ MMBTU
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr		0.0063	LB/ MMBTU
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine without Duct Burner	0			0.0063	LB/ MMBTU
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	Good combustion practices and low sulfur fuels	0.0066	LB/ MMBTU
AK-0071	INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	GE LM6000PF-25 Turbines (4)	59900	hp ISO	Good Combustion Practices	0.0066	LB/ MMBTU
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner NG only	0		Low sulfur fuels and good combustion practices	0.0068	LB/ MMBTU
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two combined cycle turbines with out duct burner	2291.64	MCF/hr	Good combustion practices and low sulfur fuels	0.0068	LB/ MMBTU

TABLE E-4
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER (TPM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Air Filter, Use of Natural Gas, Good Combustion Practices	0.008	LB/ MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H		0.0088	LB/ MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr		0.01	LB/ MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr		0.01	LB/ MMBTU
CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	7/22/2010	Four combined cycle combution turbines	373	MMBTU/H	Use of pipeline quality natural gas and good combustor design	0.01152815	LB/ MMBTU
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	PIPELINE NATURAL GAS, GOOD COMBUSTION	0.010891321	LB/ MMBTU
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Pipeline quality natural gas; good combustion practices		
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	TX	2/17/2017	Combined Cycle Cogeneration	50	MW			
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner - firing NG blend with ethane	0				
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner - firing NG blend with ethane	0				
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbine	Use of clean fuels		
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	KS	7/14/2015	Combined cycle combustion turbine	250	MW	dry low NOx burners heat recovery steam generator (HRSG)		
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	efficient combustion, natural gas fuel		
DE-0024	GARRISON ENERGY CENTER	DE	1/30/2013	Unit 1	2260	million BTUs	Fuel Usage Restriction to natural gas and low sulfur distillate oil	0.01216309	LB/ MMBTU
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Good combustion and the use of gaseous fuel		
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	good combustion and use of natural gas		
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	good combustion and natural gas as fuel		

TABLE E-4
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER (TPM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	good combustion practices		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	good combustion practices		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	180	MW	USE PUC QUALITY NATURAL GAS		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, WITH DUCT BURNING)	180	MW	USE PUC QUALITY NATURAL GAS		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	180	MW	USE PUC QUALITY NATURAL GAS		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, WITH DUCT BURNING)	180	MW	USE PUC QUALITY NATURAL GAS		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (WARM STARTUP PERIODS)	172	MW	USE NATURAL GAS		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (HOT STARTUP PERIODS)	172	MW	USE NATURAL GAS		
CA-1211	COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (SHUTDOWN PERIODS)	172	MW	USE NATURAL GAS		
TX-0590	KING POWER STATION	TX	8/5/2010	Turbine	1350	MW	use low ash fuel (natural gas or low sulfur diesel as a backup) and good combustion practices		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	154	MW	PUC QUALITY NATURAL GAS		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NORMAL OPERATION, WITH DUCT BURNING)	154	MW	PUC QUALITY NATURAL GAS		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	154	MW	PUC QUALITY NATURAL GAS		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NORMAL OPERATION, WITH DUCT BURNING)	154	MW	USE PUC QUALITY NATURAL GAS		
CA-1198	MORRO BAY POWER PLANT	CA	9/25/2008	COMBUSTION TURBINE GENERATOR	180	MW	USE PIPELINE QUALITY NATURAL GAS, OPERATE DUCT BURNERS NO MORE THAN 4000 HRS PER YEAR (12-MONTH ROLLING AVG BASIS)		
CA-1198	MORRO BAY POWER PLANT	CA	9/25/2008	COMBUSTION TURBINE GENERATOR	180	MW	USE PIPELINE QUALITY NATURAL GAS, OPERATE DUCT BURNERS NO MORE THAN 4000 HRS PER YEAR (12-MONTH ROLLING AVG BASIS)		

TABLE E-5
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VA	12/17/2010	COMBINED CYCLE TURBINE & DUCT BURNER, 3	2996	MMBTU/H	Natural Gas only, fuel has maximum sulfur content of 0.0003% by weight.	0.00030	LB/MMBTU
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1882	MMBTU/H	NATURAL GAS FUEL	0.00056	LB/MMBtu
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Use of natural gas, a clean low sulfur fuel	0.00109	LB/MMBTU
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Low Sulfur fuel	0.00110	LB/MMBTU
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Low sulfur fuel	0.00110	LB/MMBTU
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	The owner/operator will be using low sulfur fuel with a sulfur content of 0.4 grains per 100 scf.	0.00110	LB/MMBTU
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Use of natural gas a clean low sulfur fuel	0.00122	LB/MMBTU
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	low sulfur fuel, only burning natrual gas with GR/100 SCF	0.00140	LB/MMBTU
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	low sulfur fuel, only burning natural gas with 0.5 GR/100 SCF	0.00140	LB/MMBTU
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	low sulfur fuel, only burning natural gas with 0.5 GR/100 SCF	0.00140	LB/MMBTU
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	low sulfur fuel, only burning natural gas with 0.5 GR/100 SCF	0.00140	LB/MMBTU
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Low Sulfur fuel	0.00150	LB/MMBTU
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Low Sulfur Fuel	0.00150	LB/MMBTU
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	Use of only natural gas a clean burning fuel	0.00162	LB/MMBTU
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Good combustion practices and the use of pipeline quality natural gas.	0.00168	LB/MMBTU
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Good combustion practices and the use of pipeline quality natural gas.	0.00168	LB/MMBTU
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	Good Combustion Practices and use of Natural gas,a clean burning fuel.	0.00193	LB/MMBTU
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Use of natural gas only as a clean burning fuel	0.00210	LB/MMBTU
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	FUEL SPECIFICATION	0.00210	LB/MMBTU
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Use of natural gas a clean burning fuel	0.00211	LB/MMBTU
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Use of Natural gas a low sulfur fuel	0.00212	LB/MMBTU

TABLE E-5
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine -Siemens turbine without Duct Burner	33691	MMCF/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL	0.00212	LB/MMBTU
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Use of natural gas a clean burning fuel	0.00215	LB/MMBTU
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Use of natural gas a clean burning fuel	0.00217	LB/MMBTU
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG	0		Natural gas	0.00220	LB/MMBTU
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND EFFICIENT TURBINE DESIGN	0.00245	LB/MMBTU
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Use of inherently low sulfur fuel	0.00256	LB/MMBTU
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	PIPELINE QUALITY NATURAL GAS	0.00280	LB/MMBTU
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	GOOD COMBUSTION PRACTICES, LOW SULFUR FUEL	0.00280	LB/MMBTU
*TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Low sulfur fuel, good combustion practices	0.00280	LB/MMBTU
NJ-0074	WEST DEPTFORD ENERGY	NJ	5/6/2009	TURBINE, COMBINED CYCLE	17298	MMFT3/YR	USE OF CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL	0.00281	LB/MMBTU
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITHOUT DUCT FIRING	270	MW	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS	0.00283	LB/MMBTU
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Pipeline quality natural gas	0.00431	LB/MMBTU
LA-0136	PLAQUEMINE COGENERATION FACILITY	LA	7/23/2008	(4) GAS TURBINES/DUCT BURNERS	2876	MMBTU/H	LOW SULFUR FUELS WITH MAXIMUM SULFUR CONTENT OF 5 GR/100 SCF.	3.30000	PPMVD @ 15% O2
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbine	Use of low-sulfur fuels	0.00560	LB/MMBTU
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	efficient combustion, natural gas fuel	0.00560	LB/MMBTU
FL-0304	CANE ISLAND POWER PARK	FL	9/8/2008	300 MW COMBINED CYCLE COMBUSTION TURBINE	1860	MMBTU/H	FUEL SPECIFICATIONS.	0.00560	LB/MMBTU
LA-0224	ARSENAL HILL POWER PLANT	LA	3/20/2008	TWO COMBINED CYCLE GAS TURBINES	2110	MMBTU/H	USE LOW-SULFUR PIPELINE-QUALITY NATURAL GAS AS FUEL	0.00572	LB/MMBtu
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Exclusive Combustion of Low Sulfur Fuel and Proper Engineering Practices	0.00578	LB/MMBTU
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	0.01401	LB/MMBTU
*MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Use of clean fuel (natural gas) with a fuel sulfur limit of 0.8 grains per 100 standard cubic feet of natural gas.	0.06000	LB/MMBTU
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Good Combustion Practices and the use of pipeline quality natural gas.	0.06000	LB/MMBTU

TABLE E-5
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1-on-1 combined cycle unit (GE 7HA)	3266.9	MMBtu/h	Clean Fuels		
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	2-on-1 combined cycle unit (GE 7HA)	4000	MMBtu/hr	Clean fuels		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	USE OF NATURAL GAS A LOW SULFUR FUEL CLEAN FUEL	6.64	LB/H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	USE OF NATURAL GAS A CLEAN BURNING LOW SULFUR FUEL	5.62	LB/H
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Burning natural gas in an efficient combustion turbine burning low sulfur fuel	1.20	LB/H
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Burning natural gas in an efficient combustion turbine burning low sulfur fuel	1.52	LB/H
TX-0600	THOMAS C. FERGUSON POWER PLANT	TX	9/1/2011	Natural gas-fired turbines	390	MW	pipeline quality natural gas	27.07	LB/H

TABLE E-6
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON DIOXIDE EQUIVALENTS (CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0439	JACKSON GENERATING STATION	MI	4/2/2019	FGLMDB1-6 (6 combined cycle natural gas fired CTG each equipped with a HRSG)	420	MW	Use of low carbon fuel (natural gas), good combustion practices, and energy efficiency measures.	544	LB/MW-HR
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	154	MW		774	LB/MW-H
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Use of GE Frame 7EA CT Low Carbon Fuel	792	LB/MW-H
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		Energy efficiency measures	794	LB/MW-H
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).	806	LB/MW-H
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).	806	LB/MW-H
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Use of low carbon fuel	816	LB/MW-H
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H		825	LB/MW-H
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Use of Natural Gas, Model GE7HA	826	LB/MW-H
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Use of Natural Gas, Model GE7HA	829	LB/MW-H
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	state-of-the-art high efficiency combustion technology	840	LB/MW-H
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbine	Use of low-emitting fuels and technologies	850	LB/MW-H
TX-0791	ROCKWOOD ENERGY CENTER	TX	3/18/2016	Combined Cycle & Cogeneration (> 25 MW)	1127	MW	Good combustion practices	865	LB/MW-H
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW		865	LB/MW-H
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT		878	LB/MW-H

TABLE E-6
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON DIOXIDE EQUIVALENTS (CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	Good combustion practices and oxidation catalyst	883	LB/MW-H
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	PIPELINE QUALITY NATURAL GAS, GOOD COMBUSTION PRACTICES	884	LB/MW-H
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Low carbon fuel, good combustion, efficient combined cycle design	886	LB/MW-H
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Good Combustion Practices	887	LB/MW-H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	USE OS NATURAL GAS A CLEAN BURNING FUEL	888	LB/MW-H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL	888	LB/MW-H
TX-0748	FGE POWER, FGE TEXAS PROJECT	TX	4/28/2014	Combined Cycle Combustion Turbine with DB, HRSG and SCR	7625	Btu/kWh		889	LB/MW-H
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR		890	LB/MW-H
TX-0791	ROCKWOOD ENERGY CENTER	TX	3/18/2016	Combined Cycle & Cogeneration (> 25 megawatts (MW))	889	MW	Good combustion practices	901	LB/MW-H
TX-0805	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	7/19/2016	Combined Cycle & Cogeneration	462	MW	Good Combustion Practices	917	LB/MW-H
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	GOOD COMBUSTION PRACTICES	924	LB/MW-H
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	Good combustion practices	925	LB/MW-H
TX-0791	ROCKWOOD ENERGY CENTER	TX	3/18/2016	Combined Cycle & Cogeneration (> 25 MW)	889	MW	good combustion practices	929	LB/MW-H
TX-0791	ROCKWOOD ENERGY CENTER	TX	3/18/2016	Combined Cycle & Cogeneration (> 25 MW)	889	MW	good combustion practices	929	LB/MW-H
TX-0743	AUSTIN ENERGY, SAND HILL ENERGY CENTER	TX	9/29/2014	Combustion Turbine with HRSG, Duct Burners, and SCR	7943	Btu/kWh (HHV, gross)		930	LB/MW-H
TX-0787	TRINIDAD GENERATING FACILITY	TX	3/1/2016	Combined Cycle & Cogeneration	497	MW	Good Combustion Practices	937	LB/MW-H
TX-0791	ROCKWOOD ENERGY CENTER	TX	3/18/2016	Combined Cycle & Cogeneration (> 25 MW)	748	MW	Good combustion practices	944	LB/MW-H

TABLE E-6
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON DIOXIDE EQUIVALENTS (CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	EXCLUSIVE USE OF PIPELINE-QUALITY NATURAL GAS, AND INSTALLATION OF HIGH-EFFICIENCY CT MODEL (MITSUBISHI ‘‘G‘‘ MODEL)	946	LB/MW-H
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Turbine efficiency and Use of Natural gas a clean burning fuel	947	LB/MW-H
MI-0402	SUMPTER POWER PLANT	MI	11/17/2011	Combined cycle combustion turbine w/ HRSG	130	MW electrical output		954	LB/MW-H
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Pipeline quality natural gas	960	LB/MW-H
TX-0791	ROCKWOOD ENERGY CENTER	TX	3/18/2016	Combined Cycle & Cogeneration (> 25 MW)	915	MW	good combustion practices	965	LB/MW-H
TX-0810	DECORDOVA STEAM ELECTRIC STATION (DECORDOVA STATION)	TX	10/4/2016	Combined Cycle and Cogeneration (>25 MW)	213	MW	good combustion practices and firing low carbon fuel.	966	LB/MW-H
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices and energy efficiency.	995	LB/MW-H
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	TX	2/17/2017	Combined Cycle Cogeneration	50	MW		1000	LB/MW-H
*PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr		1000	LB/MW-H
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Thermal efficiency Clean fuels	1000	LB/MW-H
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Good combustion practices/energy efficiency	1000	LB/MW-H
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Good combustion practices/energy efficiency	1000	LB/MW-H
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	EFFICIENT DESIGN AND COMBUSTION.	1000	LB/MW-H
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	EFFICIENT DESIGN AND COMBUSTION.	1000	LB/MW-H

TABLE E-6
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON DIOXIDE EQUIVALENTS (CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	VA	8/27/2012	COMBUSTION TURBINES, (2)	593	MMBTU/H	Controlled by the use of low carbon fuels and high efficiency design. The heat rate shall be no greater than 8,983 Btu/kW-h (HHV, gross).	1050	LB/MW-H
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices and energy efficiency	1071	LB/MW-H
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H		1085	LB/MW-H
TN-0162	JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339	MMBtu/hr	Good combustion design and practices	1800	LB/MW-H
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Combined-Cycle Combustion Turbine	3864	mmBtu/hr	Equipment design and proper operation		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Combust low carbon fuel gas and good combustion practices		
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Combined Cycle Combustion Turbines	3474	mmBtu/hr	Equipment design and proper operation		
*MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Several energy efficiency measures and the use of natural gas.		
*TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	COMBINED CYCLE TURBINE MSS REDUCED LOAD	0		minimizing duration of startup / shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limits on the MAERT		
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCCT (Combined cycle CTG with unfired HRSG)	1934.7	MMBTU/H	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).		
*PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	low sulfur fuel and good combustion practices		
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Thermally efficient combustion turbines and good combustion practices		
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Thermally efficient combustion turbines and good combustion practices		
*PA-0306	TENASKA PA PARTNERS/WESTMOREL AND GEN FAC	PA	2/12/2016	Large combustion turbine	0		Good combustion practices		

TABLE E-6
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON DIOXIDE EQUIVALENTS (CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr			
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	KS	7/14/2015	Combined cycle combustion turbine	250	MW			
TX-0679	CORPUS CHRISTI LIQUEFACTION PLANT	TX	2/27/2015	Refrigeration Compressor Turbine	40000	hp	install efficient turbines, follow the turbine manufacturer's emission-related written instructions for maintenance activities including prescribed maintenance intervals to assure good combustion and efficient operation. Compressors shall be inspected and maintained according to a written maintenance plan to maintain efficiency.		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr			
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr			
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H			
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).		
TX-0739	AIR LIQUIDE, BAYOU COGENERATION PLANT	TX	11/21/2013	Combustion Turbine with HRSG and Duct Burners	11988	Btu/kWhr (HHV, gross)			
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat input, each CTG	No info was entered on type of add-on control. Contact permitting agency.		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	state-of-the-art high efficiency combustion technology		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	state-of-the-art high efficiency combustion technology		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	state-of-the-art high efficiency combustion technology		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR			
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H			

TABLE E-6
NATURAL-GAS FIRED COMBINED CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON DIOXIDE EQUIVALENTS (CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Energy efficient combustion practices and low GHG fuels.		
DE-0024	GARRISON ENERGY CENTER	DE	1/30/2013	Unit 1	2260	million BTUs	Fuel Usage Restriction to natural gas and low sulfur distillate fuel		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	HIGH THERMAL EFFICIENCY DESIGN		
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Good combustion practices.		
LA-0256	COGENERATION PLANT	LA	12/6/2011	COGENERATION TRAINS 1-3 (1-10, 2-10, 3-10)	475	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES		
TX-0612	THOMAS C. FERGUSON POWER PLANT	TX	11/10/2011	COMBINED CYCLE TURBINE GENERATOR U1-STK	1746	MMBTU/H	Good Combustion Practices		

TABLE E- 7
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CT-0159	CPV TOWANTIC, LLC	CT	11/30/2015	Aux Boiler	359.6	MMCF	Boiler permit does not specify any add-on control other than ultr-low NOx burner. Unit may be required to use additional control options to meet emissions limit.	0.007	lb/MMBtu
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	boiler	90	MMBTU/H	ultra low-NOx burners, limited use	0.009	lb/MMBtu
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	AUXILIARY BOILER	37.4	MMBTU/H	ULTRA LOW NOX BURNER, USE PUC QUALITY NATURAL GAS, OPERATIONAL RESTRICTION OF 46, 675 MMBTU/YR	0.009	lb/MMBtu
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	AUXILIARY BOILER	35	MMBTU/H	OPERATIONAL RESTRICTION OF 500 HR/YR	0.009	lb/MMBtu
CA-1163	BREITBURN ENERGY - DOME AND NEWLOVE LEASE, ORCUTT HILL	CA	12/8/2006	STEAM GENERATOR: OIL FIELD 5 TO <33.5 MMBTU/HR	23	23.00 MMBTU/H	LOW-NOX BURNER AND FGR	0.009	lb/MMBtu
CA-1128	COTTAGE HEALTH CARE - PUEBLO STREET	CA	5/16/2006	BOILER: 5 TO <33.5 MMBTU/H	25	MMBTU/H (75 MMBTU/H	ULTRA-LOW NOX BURNER	0.009	lb/MMBtu
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Ultra low-NOx burners and flue gas recirculation air preheater, automated combustion management systems, automated water blowdown, good combustion practices	0.010	lb/MMBtu
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	Low NOx burners and Flue Gas Recirculation (FGR) and use of natural gas a clean burning fuel	0.010	lb/MMBtu
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	Low NOx burners and Flue Gas Recirculation (FGR) and use of natural gas a clean burning fuel	0.010	lb/MMBtu
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler firing natural gas	687	MMCFT/YR	low NOx burners and flue gas recirculation (FGR)	0.010	lb/MMBtu
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	AUXILIARY BOILER	42	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, ULTRA LOW-NOX BURNERS, AND GOOD COMBUSTION PRACTICES	0.010	lb/MMBtu
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	AUXILIARY BOILER	93	MMBTU/H	EFFICIENT BOILER DESIGN WITH ULTRA LOW NOX BURNER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.010	lb/MMBtu
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.010	lb/MMBtu
TX-0680	SONORA GAS PLANT	TX	6/14/2013	Heater	10	MMBTU/H	low-NOx burners	0.010	lb/MMBtu
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Boiler less than 100 MMBtu/hr	51.9	mmcubic ft/year	Low NOx burners and flue gas recirculation	0.010	lb/MMBtu
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Commercial/Institutional size boilers less than 100 MMBtu/hr	2000	hours/year	Low NOx burners	0.010	lb/MMBtu
*WI-0283	AFE, INC. LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices	0.011	lb/MMBtu

TABLE E- 7
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	WI	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	0.011	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP26	24	MMBTU/H	LOW NOX BURNER	0.011	lb/MMBtu
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	LNB, FGR, Good Combustion Practices	0.011	lb/MMBtu
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Auxiliary Boiler	96	mmBtu/hr	Ultra-low NOx burners and flue gas recirculation, air preheater, automated combustion management system with O2 trim system and automated water blowdown, and good combustion practices.	0.011	lb/MMBtu
*PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	Auxiliary Boiler	118800	MMBtu/12 month period	"ultra-low NOx burners and flue gas re-circulation" operated in accordance with the manufacturer's specifications and good operating practices	0.011	lb/MMBtu
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Flue gas recirculation and low NOX burner	0.011	lb/MMBtu
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Auxilary boiler	92.4	MMBtu/hr	Ultra low NOx burners, FGR, good combustion practices	0.011	lb/MMBtu
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Low NOx burners and flue gas recirculation	0.011	lb/MMBtu
*MD-0041	CPV ST. CHARLES	MD	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, ULTRA LOW-NOX BURNERS, AND FLUE GAS RECIRCULATION (FGR)	0.011	lb/MMBtu
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Auxiliary Boiler	80	MMBTU/H	ultra low NOx burners	0.011	lb/MMBtu
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	AUXILIARY BOILER	40	MMBTU/H		0.011	lb/MMBtu
MD-0040	CPV ST CHARLES	MD	11/12/2008	BOILER	93	MMBTU/H	LOW NOX WITH FGR	0.011	lb/MMBtu
MD-0037	MEDIMMUNE FREDERICK CAMPUS	MD	1/28/2008	FOUR (4) NATURAL GAS BOILERS EACH RATED AT 29.4 MILLION BTU PER HOUR	29.4	MMBTU/H	ULTRA LOW NOX BURNERS ON EACH OF THE FOUR IDENTICAL BOILERS	0.011	lb/MMBtu
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	AUXILIARY BOILER	29.4	MMBTU/H	LOW NOX BURNERS & FLUE GAS RECIRCULATION	0.011	lb/MMBtu
CA-1185	SANTA BARBARA AIRPORT	CA	6/7/2011	Boiler, Forced Draft	3	MMBTU/H	Forced draft, full modulation, flue gas recirculation	0.012	lb/MMBtu
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		0.013	lb/MMBtu
LA-0240	FLOPAM INC.	LA	6/14/2010	Boilers	25.1	MMBTU/H	Ultra Low NOx Burners	0.015	lb/MMBtu
DE-0020	VALERO DELAWARE CITY REFINERY	DE	2/26/2010	PACKAGE BOILERS (2009)	99.9	MMBtu per hour	SCR AND LOW NOX BURNERS	0.015	lb/MMBtu
*WY-0075	CHEYENNE PRAIRIE GENERATING STATION	WY	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	Ultra low NOx burners and flue gas recirculation	0.018	lb/MMBtu

TABLE E- 7
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0575	SABINA PETROCHEMICALS LLC	TX	8/20/2010	BOILER	228	SCF/H	LOW NOX BURNERS AND SCR	0.020	lb/MMBtu
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	NATURAL GAS FIRED AUXILIARY BOILER	88	MMBtu/hr	Lo-NOx burners, Flue Gas Recirculation, good combustion practices, proper operation and maintainance.	0.020	lb/MMBtu
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	low NOX burners and flue gas recirculation	0.020	lb/MMBtu
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Flue gas recirculation (FGR), low NOx burner	0.020	lb/MMBtu
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Auxiliary Boiler (B001)	99	MMBTU/H	Flue gas recirculation (FGR), low NOx burner, and natural gas/ultra low sulfur diesel	0.020	lb/MMBtu
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Auxillary Boiler	99	MMBtu/H	low NOx burners and flue gas recirculation	0.020	lb/MMBtu
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	MI	3/24/2017	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	3	MMBTU/H	Ultra-low NOx burners and good combustion practices.	0.021	lb/MMBtu
CA-1189	PETROROCK- TUNNELL LEASE	CA	1/24/2012	Boiler	2	MMBTU/H	Low NOx Burner	0.021	lb/MMBtu
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Good combustion practices and low NOx burner	0.027	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA01	16.8	MMBTU/H	LOW-NOX BURNER AND BLUE GAS RECIRCULATION	0.030	lb/MMBtu
WY-0067	ECHO SPRINGS GAS PLANT	WY	4/1/2009	HOT OIL HEATER S38	84	MMBTU/H	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.030	lb/MMBtu
NV-0047	NELLIS AIR FORCE BASE	NV	2/26/2008	BOILERS/HEATERS - NATURAL GAS-FIRED			LOW-NOX BURNER AND FLUE GAS RECIRCULATION	0.030	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA03	31.38	MMBTU/H	LOW-NOX BURNER	0.031	lb/MMBtu
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	99	MMBTU/H	Low NOx burners (LNB) or flue gas recirculation along with good combustion practices.	0.031	lb/MMBtu
TN-0160	VOLKSWAGEN GROUP OF AMERICA, CHATTANOOGA OPERATIONS	TN	10/10/2008	NATURAL GAS-FIRED BOILERS (3)	24	MMBTU/H	LOW-NOX BURNERS, FLUE GAS RECIRCULATION	0.031	lb/MMBtu
GA-0130	KIA MOTORS MANUFACTURING GEORGIA	GA	7/27/2007	BOILERS AND HEATERS			LOW NOX BURNERS ON BOILER BURNERS	0.031	lb/MMBtu
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	LOW NOX BURNER WITH FLUE GAS RECIRCULATION	0.032	lb/MMBtu
NH-0015	CONCORD STEAM CORPORATION	NH	2/27/2009	BOILER 3 (AUXILIARY)	76.8	MMBTU/H	LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND LESS THAN 700 HOURS OF OPERATION PER CONSECUTIVE 12 MONTH PERIOD.	0.032	lb/MMBtu
NH-0015	CONCORD STEAM CORPORATION	NH	2/27/2009	BOILER 2 (AUXILIARY)	76.8	MMBTU/H	LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND LESS THAN 700 HOURS OPERATION PER CONSECUTIVE 12 MONTH PERIOD.	0.032	lb/MMBtu
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	9/7/2007	SMALL BOILERS & HEATERS (<100 MMBTU/H)	99	MMBTU/H		0.0350	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, PICKLE LINE	0		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Low NOx burners, Combustion of clean fuel, and Good Combustion Practices	0.035	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	lb/MMBtu

TABLE E- 7
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, VACUUM DEGASSER	88.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE LOW NOX BURNERS	0.035	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, PICKLE LINE	53.7	MMBTU/HR	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER SN-26, GALVANIZING LINE	53.7	MMBTU/HR	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	lb/MMBtu
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Good combustion practices and low NOx burner	0.035	lb/MMBtu
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Utilize Low-NOx burners and FGR.	0.035	lb/MMBtu
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices.	0.035	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP01	35.4	MMBTU/H	LOW NOX BURNER	0.035	lb/MMBtu
SC-0112	NUCOR STEEL - BERKELEY	SC	5/5/2008	VACUUM DEGASSER BOILER	50.21	MMBTU/H	ULTRA-LOW NOX NATURAL GAS FIRED BURNERS	0.035	lb/MMBtu
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	8/17/2007	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.9	MMBTU each	ULNB & EGR (ULTRA-LOW NOX BURNERS (ULNB)(EXHAUST GAS RECIRCULATION (EGR) SAME FLUE GAS RECIRCULATION (FGR)	0.035	lb/MMBtu
AL-0231	NUCOR DECATUR LLC	AL	6/12/2007	VACUUM DEGASSER BOILER	95	MMBTU/H	ULTRA LOW NOX BURNERS	0.035	lb/MMBtu
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	5/3/2007	BOILER (2), NATURAL GAS	20.4	MMBTU/H	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.035	lb/MMBtu
NV-0044	HARRAH'S OPERATING COMPANY, INC.	NV	1/4/2007	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	LOW-NOX BURNER AND FLUE GAS RECIRCULATION	0.035	lb/MMBtu
*MI-0393	RAY COMPRESSOR STATION	MI	10/14/2010	Auxiliary Boiler	12.25	MMBTU/H	Low NOx burner.	0.035	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT FL01	14.34	MMBTU/H	LOW NOX BURNER AND FLUE GAS RECIRCULATION	0.035	lb/MMBtu
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Low NOx burners/Flue gas recirculation.	0.036	lb/MMBtu
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	40	MMBTU/H	Low NOx burners	0.036	lb/MMBtu
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	boiler	80	MMBTU/H	low-NOx burners	0.036	lb/MMBtu
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU004	46	MMBTU/H		0.036	lb/MMBtu
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU005	46	MMBTU/H		0.036	lb/MMBtu
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU006	46	MMBTU/H		0.036	lb/MMBtu
FL-0335	SUWANNEE MILL	FL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46	MMBTU/H	Low NOx Burner and Flue Gas Recirculation	0.036	lb/MMBtu
OK-0136	PONCA CITY REFINERY	OK	2/9/2009	TB-1, TB-2, TB-3	95	MMBTU/H	ULTRA-LOW NOX BURNERS; 0.036 LB/MMBTU.	0.036	lb/MMBtu
OK-0137	PONCA CITY REFINERY	OK	2/9/2009	TB-1 Leased Boiler No. 1	95	MMBTU/H	Ultra-low NOx burners (0.036lb/mmbtu)	0.036	lb/MMBtu
OK-0137	PONCA CITY REFINERY	OK	2/9/2009	TB-2 Leased Boiler No.2	95	MMBTU/H	ULNB- Ultra-low NOx burners , 0.036lb/mmbtu	0.036	lb/MMBtu
*AL-0307	ALLOYS PLANT	AL	10/9/2015	PACKAGE BOILER	17.5	MMBTU/H	LOW NOX BURNER FLUE GAS RECIRCULATION GCP	0.037	lb/MMBtu

TABLE E- 7
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*AL-0307	ALLOYS PLANT	AL	10/9/2015	2 CALP LINE BOILERS	24.59	MMBTU/H	LOW NOX BURNER FLUE GAS RECIRCULATION (FGR) GOOD COMBUSTION PRACTICES (GCP)	0.037	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP03	33.48	MMBTU/H	LOW NOX BURNER	0.037	lb/MMBtu
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	Low NOx burners/flue gas recirculation and good combustion practices.	0.040	lb/MMBtu
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Low NOx burners/flue gas recirculation and good combustion practices.	0.040	lb/MMBtu
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010	EQT0323 - Boiler 401F	99	MMBTU/H	Ultra low NOX burners and/or CSR	0.040	lb/MMBtu
WA-0316	NORTHWEST PIPELINE CORP.-MT VERNON COMPRESSOR	WA	6/14/2006	BOILER, NATURAL GAS	4.19	MMBTU/H	GOOD COMBUSTION PRACTICE	0.040	lb/MMBtu
OH-0379	PETMIN USA INCORPORATED	OH	2/6/2019	Startup boiler (B001)	15.17	MMBTU/H	Low-NOX burners, good combustion practices and the use of natural gas	0.042	lb/MMBtu
*OK-0148	BUFFALO CREEK PROCESSING PLANT	OK	9/12/2012	Commercial/Institutional Boilers (<100 MMBTUH)	11.04	MMBTUH	Low-NOx burners	0.045	lb/MMBtu
OH-0323	TITAN TIRE CORPORATION OF BRYAN	OH	6/5/2008	BOILER	50.4	MMBTU/H		0.049	lb/MMBtu
OR-0048	CARTY PLANT	OR	12/29/2010	NATURAL GAS-FIRED BOILER	91	MMBTU/H	LOW NOX BURNERS	0.049	lb/MMBtu
*FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	60 MMBtu/hour Auxiliary Boiler	60	MMBtu/hour	low-NOx burners	0.050	lb/MMBtu
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUAUXBOILER (Auxiliary boiler)	83.5	MMBTU/H	Low NOx burners/Internal flue gas recirculation and good combustion practices.	0.050	lb/MMBtu
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Auxiliary Boiler, 99.8 MMBtu/hr	99.8	MMBtu/hr	Low-NOx burners	0.050	lb/MMBtu
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	95	MMBTU/H	Dry low NOx burners, flue gas recirculation and good combustion practices.	0.050	lb/MMBtu
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	55	MMBTU/H	Low NOx burners and good combustion practices	0.050	lb/MMBtu
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGAUXBOILERS: Two auxiliary boilers <100 MMBTU/H heat input each	100	MMBTU/H heat input each	Low NOx burners and flue gas recirculation.	0.050	lb/MMBtu
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	99.8	MMBTU/H		0.050	lb/MMBtu
OH-0350	REPUBLIC STEEL	OH	7/18/2012	Steam Boiler	65	MMBtu/H		0.070	lb/MMBtu
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	AUXILIARY BOILER	33.5	MMBTU/H	LOW-NOX BURNERS	0.070	lb/MMBtu
AR-0090	NUCOR STEEL, ARKANSAS	AR	4/3/2006	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	LOW NOX BURNERS	0.075	lb/MMBtu
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	7/11/2006	POWER STEAM BOILER	93	MMBTU/H		0.090	lb/MMBtu
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.2	MMBTU/H		0.100	lb/MMBtu
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.100	lb/MMBtu

TABLE E- 7
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.101	lb/MMBtu
OK-0135	PRYOR PLANT CHEMICAL	OK	2/23/2009	BOILERS #1 AND #2	80	MMBTU/H	LOW-NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.200	lb/MMBtu
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Commercial/Institutional Size Boilers (<100 MMBtu) natural gas	73.3	MMBTU/H			
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Auxiliary Boiler	40	MMBTU/H			
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	BOILERS	5	MMBTU/H	GOOD DESIGN AND COMBUSTION PRACTICES, LOW NOX BURNERS, COMBUSTION OF NATURAL GAS/PROPANE.		

TABLE E-8
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MA-0039	FOOTPRINT POWER SALEM HARBOR STATION	MA	1/30/2014	Auxiliary Boiler	80	MMBTU/H	Oxidation catalyst	0.0035	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP01	35.4	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0073	LB/MMBTU
OK-0168	SEMINOLE GNRTNG STA	OK	5/5/2015	NATURAL GAS-FIRED BOILER (<100MMBTUH)	40.4	MMBTUH	NO CONTROLS FEASIBLE;GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP03	33.48	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0075	LB/MMBTU
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Package Boilers (2 identical, B003 and B004)	265	MMBTU/H	good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing)	0.015	LB/MMBTU
*WI-0283	AFE, INC. â€"LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices	0.016	LB/MMBTU
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	WI	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	0.016	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	auxiliary boiler	60.1	mmBtu/hr	CO catalytic oxidizer	0.0164	LB/MMBTU
CA-1163	BREITBURN ENERGY - DOME AND NEWLOVE LEASE, ORCUTT HILL	CA	12/8/2006	STEAM GENERATOR: OIL FIELD 5 TO < 33.5 MMBTU/HR	23	23.00 MMBTU/H	LOW-NOX BURNER AND FGR	0.016	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA03	31.38	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION.	0.0172	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA01	16.8	MMBTU/H	FLUE GAS RECIRCULATION	0.0173	LB/MMBTU
*MD-0041	CPV ST. CHARLES	MD	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU
MD-0040	CPV ST CHARLES	MD	11/12/2008	BOILER	93	MMBTU/H		0.02	LB/MMBTU
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Good combustion practices	0.031	LB/MMBTU
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	99	MMBTU/H	Good combustion practices	0.032	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	40	MMBTU/H	Good combustion practice to ensure complete combustion.	0.032	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Good combustion practice to ensure complete combustion.	0.032	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.2	MMBTU/H	Good combustion practice to ensure complete combustion.	0.032	LB/MMBTU
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Commercial/Institutional Size Boilers (<100 MMBtu); natural gas	73.3	MMBTU/H		0.032	LB/MMBTU
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	Auxiliary Boiler (30.6 mmBtu/hr)	263000000	standard cubic ft	clean fuel (natural gas) and good combustion practices	0.032	LB/MMBTU
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	AUXILIARY BOILER	37.4	MMBTU/H	ULTRA LOW NOX BURNER, USE PUC QUALITY NATURAL GAS, OPERATIONAL RESTRICTION OF 46, 675 MMBTU/YR	0.032	LB/MMBTU
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	AUXILIARY BOILER	35	MMBTU/H	OPERATIONAL RESTRICTION OF 500 HR/YR	0.032	LB/MMBTU

TABLE E-8
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CA-1128	COTTAGE HEALTH CARE - PUEBLO STREET	CA	5/16/2006	BOILER: 5 TO <33.5 MMBTU/H	25	MMBTU/H (75 MMBTU/H	ULTRA-LOW NOX BURNER	0.032	LB/MMBTU
*PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	Auxiliary Boiler	118800	MMBtu/12 month period		0.036	LB/MMBTU
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.036	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices	0.036	LB/MMBTU
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	AUXILIARY BOILER	40	MMBTU/H		0.036	LB/MMBTU
NV-0044	HARRAH'S OPERATING COMPANY, INC.	NV	1/4/2007	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	GOOD COMBUSTION DESIGN	0.036	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	AUXILIARY BOILER	29.4	MMBTU/H	GOOD COMBUSTION PRACTICES	0.036	LB/MMBTU
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL	OH	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Good combustion controls	0.037	LB/MMBTU
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	0.037	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practices	0.037	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Auxilary boiler	92.4	MMBtu/hr	ULSD and good combustion practices	0.037	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	AUXILIARY BOILER	42	MMBTU/H	GOOD COMBUSTION PRACTICES	0.037	LB/MMBTU
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	boiler	80	MMBTU/H	low-NOx burners	0.037	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP26	24	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.037	LB/MMBTU
NV-0047	NELLIS AIR FORCE BASE	NV	2/26/2008	BOILERS/HEATERS - NATURAL GAS-FIRED			FLUE GAS RECIRCULATION	0.037	LB/MMBTU
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	Good Combustion Practices	0.037	LB/MMBTU
LA-0240	FLOPAM INC.	LA	6/14/2010	Boilers	25.1	MMBTU/H	Good equipment design and proper combustion practices	0.037	LB/MMBTU
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Good combustion practices	0.037	LB/MMBTU
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	SC	5/21/2019	Boiler No. 2	0		Work Practice Standards	0.0375	LB/MMBTU
*WY-0075	CHEYENNE PRAIRIE GENERATING STATION	WY	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	good combustion	0.0375	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU004	46	MMBTU/H		0.039	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU005	46	MMBTU/H		0.039	LB/MMBTU

TABLE E-8
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU006	46	MMBTU/H		0.039	LB/MMBTU
FL-0335	SUWANNEE MILL	FL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46	MMBTU/H	Good Combustion Practice	0.039	LB/MMBTU
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Utilize Low-NOx burners and FGR.	0.04	LB/MMBTU
OH-0350	REPUBLIC STEEL	OH	7/18/2012	Steam Boiler	65	MMBtu/H	Proper burner design and good combustion practices	0.04	LB/MMBTU
OK-0136	PONCA CITY REFINERY	OK	2/9/2009	TB-1, TB-2, TB-3	95	MMBTU/H	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICE; 0.04 LB/MMBTU	0.040	LB/MMBTU
OK-0137	PONCA CITY REFINERY	OK	2/9/2009	TB-1 Leased Boiler No. 1	95	MMBTU/H	Ultra-low NOx burners and good combustion practices, 0.04lb/mmbtu	0.040	LB/MMBTU
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	8/17/2007	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.9	MMBTU each		0.04	LB/MMBTU
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	NATURAL GAS FIRED AUXILIARY BOILER	88	MMBtu/hr	Lo-NOx burners, Flue Gas Recirculation, good combustion practices, proper operation and maintainance.	0.055	LB/MMBTU
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	good combustion controls	0.055	LB/MMBTU
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Good combustion controls	0.055	LB/MMBTU
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Auxillary Boiler	99	MMBtu/H	Good combustion practices and using combustion optimization technology	0.055	LB/MMBTU
SC-0112	NUCOR STEEL - BERKELEY	SC	5/5/2008	VACUUM DEGASSER BOILER	50.21	MMBTU/H	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.061	LB/MMBTU
CA-1185	SANTA BARBARA AIRPORT	CA	6/7/2011	Boiler, Forced Dratf	3	MMBTU/H	Forced draft, full modulation, flue gas recirculation	0.063	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT FL01	14.34	MMBTU/H	FLUE GAS RECIRCULATION	0.0705	LB/MMBTU
*OK-0148	BUFFALO CREEK PROCESSING PLANT	OK	9/12/2012	Commercial/Institutional Boilers (<100 MMBTUH)	11.04	MMBTUH		0.074	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Good combustion practices	0.075	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGAUXBOILERS: Two auxiliary boilers < 100 MMBTU/H heat input each	100	MMBTU/H heat input each	Efficient combustion.	0.075	LB/MMBTU
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	7/11/2006	POWER STEAM BOILER	93	MMBTU/H		0.076	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUAUXBOILER (Auxiliary boiler)	83.5	MMBTU/H	Good combustion practices.	0.077	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	95	MMBTU/H	Good combustion practices.	0.077	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	55	MMBTU/H	Good combustion practices	0.077	LB/MMBTU
*FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	60 MMBtu/hour Auxiliary Boiler	60	MMBtu/hour	Good combustion practices and low-NOx burners	0.08	LB/MMBTU

TABLE E-8
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	Good combustion practices.	0.08	LB/MMBTU
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Good combustion practices.	0.08	LB/MMBTU
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	99.8 MMBtu/hr auxiliary boiler	99.8	MMBtu/hr	Clean fuel	0.08	LB/MMBTU
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Auxiliary Boiler (B001)	99	MMBTU/H	Good combustion controls and natural gas/ultra low sulfur diesel	0.080	LB/MMBTU
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Auxiliary Boiler, 99.8 MMBtu/hr	99.8	MMBtu/hr	Proper combustion prevents CO	0.08	LB/MMBTU
*AL-0307	ALLOYS PLANT	AL	10/9/2015	PACKAGE BOILER	17.5	MMBTU/H	GCP	0.08	LB/MMBTU
*AL-0307	ALLOYS PLANT	AL	10/9/2015	2 CALP LINE BOILERS	24.59	MMBTU/H	GCP	0.08	LB/MMBTU
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	AUXILIARY BOILER	93	MMBTU/H	EFFICIENT BOILER DESIGN AND APPLICATION OF GOOD COMBUSTION PRACTICES.	0.08	LB/MMBTU
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	9/7/2007	SMALL BOILERS & HEATERS(<100 MMBTU/H)	99	MMBTU/H		0.08	LB/MMBTU
FL-0285	PROGRESS BARTOW POWER PLANT	FL	1/26/2007	ONE GASEOUS-FUELED 99 MMTU/HR AUXILIARY BOILER	99	MMBTU/H		0.08	LB/MMBTU
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	99.8	MMBTU/H		0.08	LB/MMBTU
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010	EQT0323 - Boiler 401F	99	MMBTU/H	Proper design and operation, good combustion practices and gaseous fuels	0.082	LB/MMBTU
OH-0323	TITAN TIRE CORPORATION OF BRYAN	OH	6/5/2008	BOILER	50.4	MMBTU/H		0.082	LB/MMBTU
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	MI	3/24/2017	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B,	3	MMBTU/H	Good combustion practices and clean burn fuel (pipeline quality natural gas).	0.082	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, PICKLE LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0824	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Combustion of Natural gas and Good Combustion Practice	0.0824	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0824	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, PICKLE LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0824	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER SN-26, GALVANIZING LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0824	LB/MMBTU
OK-0135	PRYOR PLANT CHEMICAL	OK	2/23/2009	BOILERS #1 AND #2	80	MMBTU/H	GOOD COMBUSTION PRACTICES	0.083	LB/MMBTU
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	GOOD COMBUTSTION PRACTICES	0.083	LB/MMBTU
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.083	LB/MMBTU

TABLE E-8
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.083	LB/MMBTU
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	5/3/2007	BOILER (2), NATURAL GAS	20.4	MMBTU/H		0.083	LB/MMBTU
WI-0259	MANITOWOC PUBLIC UTILITIES	WI	4/16/2012	B10 - Natural Gas-Fired Package Boiler	33	MMBtu per hour		0.109	LB/MMBTU
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	AUXILIARY BOILER	33.5	MMBTU/H	GOOD COMBUSTION	0.150	LB/MMBTU
AR-0090	NUCOR STEEL, ARKANSAS	AR	4/3/2006	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	GOOD COMBUSTION PRACTICE	0.254	LB/MMBTU
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES		
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler firing natural gas	687	MMCFT/YR	Use of good combustion practices and use of natural gas a clean burning fuel		
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Auxiliary Boiler	40	MMBTU/H			
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Boiler less than 100 MMBtu/hr	51.9	mmcubic ft/year	use of natural gas a clean fuel		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Commercial/Institutional size boilers less than 100 MMBtu/hr	2000	hours/year	Use of natural gas and good combustion practices		
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	BOILERS	5	MMBTU/H	GOOD COMBUSTION PRACTICES. CONSUMPTION OF NATURAL GAS AND PROPANE.		
*OK-0142	WAYNOKA NATURAL GAS PROCESSING PLANT	OK	1/17/2012	Commercial/Institutional Boilers/Furnaces (<100 MMBTUH)	5	MMBTUH			

TABLE E-9
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Auxiliary Boiler	40	MMBTU/H		0.0008	lb/MMBtu
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Commercial/Institutional Size Boilers (<100 MMBtu); natural gas	73.3	MMBTU/H		0.0014	lb/MMBtu
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	AUXILIARY BOILER	40	MMBTU/H		0.0015	lb/MMBtu
*WY-0075	CHEYENNE PRAIRIE GENERATING STATION	WY	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	good combustion practices	0.0017	lb/MMBtu
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	AUXILIARY BOILER	93	MMBTU/H	EFFICIENT BOILER DESIGN, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, THE USE OF ULTRA-LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES	0.0020	lb/MMBtu
*MD-0041	CPV ST. CHARLES	MD	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES	0.002	lb/MMBtu
MD-0040	CPV ST CHARLES	MD	11/12/2008	BOILER	93	MMBTU/H		0.002	lb/MMBtu
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	AUXILIARY BOILER	42	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES	0.003	lb/MMBtu
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU004	46	MMBTU/H		0.003	lb/MMBtu
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU005	46	MMBTU/H		0.003	lb/MMBtu
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU006	46	MMBTU/H		0.003	lb/MMBtu
FL-0335	SUWANNEE MILL	FL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46	MMBTU/H	Good Combustion Practice	0.003	lb/MMBtu
LA-0240	FLOPAM INC.	LA	6/14/2010	Boilers	25.1	MMBTU/H	Good equipment design and proper combustion techniques	0.003	lb/MMBtu
CA-1163	BREITBURN ENERGY - DOME AND NEWLOVE LEASE, ORCUTT HILL FIELD	CA	12/8/2006	STEAM GENERATOR: OIL FIELD 5 TO < 33.5 MMBTU/HR	23	23.00 MMBTU/H	LOW-NOX BURNER AND FGR (VOC AS ROC)	0.0031	lb/MMBtu
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Good combustion practices	0.0031	lb/MMBtu
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	THE EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, LIMITED HOURS OF OPERATION, AND GOOD COMBUSTION PRACTICES	0.0033	lb/MMBtu
*WI-0283	AFE, INC. â€"LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices	0.0036	lb/MMBtu
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	WI	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	0.0036	lb/MMBtu
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Good combustion practices	0.0036	lb/MMBtu

TABLE E-9
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	Good combustion practices.	0.004	lb/MMBtu
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Good combustion practices.	0.004	lb/MMBtu
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Auxilary boiler	92.4	MMBtu/hr	ULSD and good combustion practices	0.004	lb/MMBtu
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler firing natural gas	687	MMCFT/YR	Use of good combustion practices and use of natural gas a clean burning fuel	0.0040	lb/MMBtu
*MI-0393	RAY COMPRESSOR STATION	MI	10/14/2010	Auxiliary Boiler	12.25	MMBTU/H		0.0041	lb/MMBtu
MA-0039	FOOTPRINT POWER SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Auxiliary Boiler	80	MMBTU/H	oxidation catalyst	0.0043	lb/MMBtu
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	7/11/2006	POWER STEAM BOILER	93	MMBTU/H		0.0049	lb/MMBtu
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Good combustion controls	0.005	lb/MMBtu
*PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	Auxiliary Boiler	118800	MMBtu/12 month period		0.005	lb/MMBtu
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		0.005	lb/MMBtu
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Utilize Low-NOx burners and FGR.	0.005	lb/MMBtu
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices.	0.005	lb/MMBtu
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	GOOD COMBUSTION PRACTICES	0.005	lb/MMBtu
NV-0044	HARRAH'S OPERATING COMPANY, INC.	NV	1/4/2007	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	GOOD COMBUSTION DESIGN	0.005	lb/MMBtu
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.005	lb/MMBtu
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	99	MMBTU/H	Good combustion practices.	0.0051	lb/MMBtu
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.2	MMBTU/H	Good combustion practice to ensure complete combustion.	0.0052	lb/MMBtu
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	GOOD COMBUSTION PROCESS	0.0052	lb/MMBtu
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010	EQT0323 - Boiler 401F	99	MMBTU/H	Proper design and operation, good combustion practices and gaseous fuels	0.0054	lb/MMBtu
OH-0323	TITAN TIRE CORPORATION OF BRYAN	OH	6/5/2008	BOILER	50.4	MMBTU/H		0.0054	lb/MMBtu

TABLE E-9
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	40	MMBTU/H	Good combustion practice to ensure complete combustion.	0.0054	lb/MMBtu
OH-0350	REPUBLIC STEEL	OH	7/18/2012	Steam Boiler	65	MMBtu/H	Proper burner design and good combustion practices	0.0054	lb/MMBtu
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	SC	5/21/2019	Boiler No. 2	0		Work Practice Standards	0.0054	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, PICKLE LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0054	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Combustion of Natural gas and Good Combustion Practice	0.0054	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0054	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, VACUUM DEGASSER	88.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0054	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, PICKLE LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0054	lb/MMBtu
AL-0282	LENZING FIBERS, INC.	AL	1/22/2014	Natural Gas Fired Boilers (3)	100	mm btu/hr	Good combustion Practices.	0.0054	lb/MMBtu
SC-0160	US8 FACILITY	SC	12/13/2012	BOILERS (BL01) & (BL02)	33.6	MMBTU/H		0.0054	lb/MMBtu
*OK-0148	BUFFALO CREEK PROCESSING PLANT	OK	9/12/2012	Commercial/Institutional Boilers (<100 MMBTUH)	11.04	MMBTUH		0.0054	lb/MMBtu
AL-0280	LENZING FIBERS, INC.	AL	12/6/2011	Natural Gas Fired Broiler #3	100	MMBTU/Hr	Good combustion practices	0.0054	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT FL01	14.34	MMBTU/H	FLUE GAS RECIRCULATION	0.0054	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA01	16.8	MMBTU/H	FLUE GAS RECIRCULATION	0.0054	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA03	31.38	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP01	35.4	MMBTU/H	FLUE GAS RECIRCULATION AND OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP03	33.48	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	lb/MMBtu
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP26	24	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	lb/MMBtu
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	5/3/2007	BOILER (2), NATURAL GAS	20.4	MMBTU/H		0.0054	lb/MMBtu
*WI-0289	GEORGIA-PACIFIC CONSUMER PRODUCTS LLC	WI	4/1/2019	B98 & B99 Natural Gas Fired Temporary Boilers	95	mmBTU/hr	Good Combustion Practices	0.0055	lb/MMBtu
WI-0266	GREEN BAY PACKAGING, INC. - SHIPPING CONTAINER DIVISION	WI	9/6/2018	Natural gas-fied boiler (Boiler B01)	35	mmBtu/hr	Good combustion practices, use only natural gas, equip boiler with Low NOx burners and flue gas recirculation	0.0055	lb/MMBtu
MO-0082	ARCHER DANIELS MIDLAND-MEXICO	MO	10/5/2010	DUAL-FIRED 85.6 MMBTU/HR WATER-TUBE BOILER	85.6	MMBTU/H	GOOD COMBUSTION PRACTICES	0.0055	lb/MMBtu
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	8/17/2007	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.9	MMBTU each		0.0055	lb/MMBtu

TABLE E-9
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MS-0085	DART CONTAINER CORPORATION LLC	MS	1/31/2007	NATURAL GAS FIRED BOILER	33.5	MMBTU/h		0.0055	lb/MMBtu
AR-0090	NUCOR STEEL, ARKANSAS	AR	4/3/2006	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	GOOD COMBUSTION PRACTICE	0.0055	lb/MMBtu
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	good combustion controls	0.006	lb/MMBtu
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Good combustion controls	0.006	lb/MMBtu
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Auxiliary Boiler (B001)	99	MMBTU/H	Good combustion controls and natural gas/ultra low sulfur diesel	0.006	lb/MMBtu
*AL-0307	ALLOYS PLANT	AL	10/9/2015	PACKAGE BOILER	17.5	MMBTU/H	GCP	0.006	lb/MMBtu
*AL-0307	ALLOYS PLANT	AL	10/9/2015	2 CALP LINE BOILERS	24.59	MMBTU/H	GCP	0.006	lb/MMBtu
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Auxillary Boiler	99	MMBtu/H	Good combustion practices and using combustion optimization technologies	0.006	lb/MMBtu
NV-0047	NELLIS AIR FORCE BASE	NV	2/26/2008	BOILERS/HEATERS - NATURAL GAS-FIRED			FLUE GAS RECIRCULATION	0.0062	lb/MMBtu
OK-0135	PRYOR PLANT CHEMICAL	OK	2/23/2009	BOILERS #1 AND #2	80	MMBTU/H		0.0063	lb/MMBtu
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Good combustion practices	0.008	lb/MMBtu
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	Use of Natural Gas, Good Combustion Practices	0.008	lb/MMBtu
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUAUXBOILER (Auxiliary boiler)	83.5	MMBTU/H	Good combustion practices.	0.008	lb/MMBtu
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	95	MMBTU/H	Good combustion practices	0.008	lb/MMBtu
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	55	MMBTU/H	Good combustion control	0.008	lb/MMBtu
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGAUXBOILERS: Two auxiliary boilers < 100 MMBTU/H heat input each	100	MMBTU/H heat input each	Efficient combustion; natural gas fuel.	0.008	lb/MMBtu
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Good combustion practice to ensure complete combustion.	0.0129	lb/MMBtu
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	AUXILIARY BOILER	33.5	MMBTU/H	GOOD COMBUSTION	0.0161	lb/MMBtu
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Boiler less than 100 MMBtu/hr	51.9	mmcubic ft/year	use of natural gas a clean fuel	0.0447	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER SN-26, GALVANIZING LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.054	lb/MMBtu
VA-0327	PERDUE GRAIN AND OILSEED, LLC	VA	7/12/2017	(4) 27 MMBtu/hr boilers, Natural gas and No. 2 fuel oi	0				
TX-0813	ODESSA PETROCHEMICAL PLANT	TX	11/22/2016	small Boiler	39.9	MMBtu/hr	best combustion practices		
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Commercial/Institutional size boilers less than 100 MMBtu/hr	2000	hours/year	Use of Natural Gas		

TABLE E-9
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	BOILERS	5	MMBTU/H	GOOD COMBUSTION PRACTICES. CONSUMPTION OF NATURAL GAS AND PROPANE AS FUEL.		
FL-0285	PROGRESS BARTOW POWER PLANT	FL	1/26/2007	ONE GASEOUS-FUELED 99 MMTU/HR AUXILIARY BOILER	99	MMBTU/H			
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	99.8	MMBTU/H			

TABLE E-10
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER (TPM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER SN-26, GALVANIZING LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0007	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0007	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, VACUUM DEGASSER	88.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0009	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST	MI	12/5/2016	EUAUXBOILER (Auxiliary boiler)	83.5	MMBTU/H	Good combustion practices.	0.0018	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	95	MMBTU/H	Good combustion practices	0.0018	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	55	MMBTU/H	Good combustion practices	0.0018	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGAUXBOILERS: Two auxiliary boilers <100 MMBTU/H heat input each	100	MMBTU/H heat input each	Efficient combustion; natural gas fuel.	0.0018	LB/MMBTU
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Commercial/Institutional size boilers less than 100 MMBtu/hr	2000	hours/year	use of Natural gas	0.0019	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, PICKLE LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0019	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Combustion of Natural gas and Good Combustion Practice	0.0019	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, PICKLE LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0019	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	AUXILIARY BOILER	42	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0019	LB/MMBTU
OH-0309	TOLEDO SUPPLIER PARK-PAINT SHOP	OH	5/3/2007	BOILER (2), NATURAL GAS	20.4	MMBTU/H		0.0019	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU004	46	MMBTU/H		0.002	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU005	46	MMBTU/H		0.002	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	SC	1/3/2013	NATURAL GAS BOILER EU006	46	MMBTU/H		0.002	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC	PA	12/17/2013	Auxiliary Boiler	40	MMBTU/H		0.0026	LB/MMBTU
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING	NJ	3/10/2016	Auxiliary Boiler firing natural gas	687	MMCFT/YR	Use of natural gas a clean burning	0.0033	LB/MMBTU
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	AUXILIARY BOILER	37.4	MMBTU/H	USE PUC QUALITY NATURAL GAS, OPERATIONAL LIMIT OF 46,675 MMBTU/YR	0.0042	LB/MMBTU
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boiler	61.5	MMBTU/H	Good combustion practices.	0.005	LB/MMBTU
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Good combustion practices.	0.005	LB/MMBTU

TABLE E-10
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER (TPM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MD-0041	CPV ST. CHARLES	MD	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.005	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices.	0.005	LB/MMBTU
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	AUXILIARY BOILER	40	MMBTU/H		0.005	LB/MMBTU
LA-0240	FLOPAM INC.	LA	6/14/2010	Boilers	25.1	MMBTU/H	Good equipment design and proper combustion practices, fueled by natural gas/alcohol	0.005	LB/MMBTU
MD-0040	CPV ST CHARLES	MD	11/12/2008	BOILER	93	MMBTU/H		0.005	LB/MMBTU
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Pipeline quality natural gas	0.006	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Good combustion practices, low sulfur fuel	0.007	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Auxilary boiler	92.4	MMBtu/hr	ULSD and good combustion practices	0.007	LB/MMBTU
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WV	6/14/2018	WH-1 - Boiler	8.72	mmBtu/hr	Limited to natural gas.	0.0073	LB/MMBTU
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	0.0075	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practices	0.0075	LB/MMBTU
*WI-0283	AFE, INC. â€"LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Good Combustion Practices	0.0075	LB/MMBTU
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -	WI	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Good Combustion Practices and The Use of Pipeline Quality Natural Gas	0.0075	LB/MMBTU
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Pipeline quality natural gas	0.0075	LB/MMBTU
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	AUXILIARY BOILER	93	MMBTU/H	EFFICIENT BOILER DESIGN, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, AND APPLICATION OF GOOD COMBUSTION	0.0075	LB/MMBTU
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
AL-0282	LENZING FIBERS, INC.	AL	1/22/2014	Natural Gas Fired Boilers (3)	100	mm btu/hr	Good combustion Practices.	0.0075	LB/MMBTU
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	GOOD COMBUSTION PRACTICES AND FUEL SPECIFICATIONS	0.0075	LB/MMBTU
AL-0280	LENZING FIBERS, INC.	AL	12/6/2011	Natural Gas Fired Boiler #3	100	MMBTU/Hr	Good Combustion Practices	0.0075	LB/MMBTU
OK-0135	PRYOR PLANT CHEMICAL	OK	2/23/2009	BOILERS #1 AND #2	80	MMBTU/H		0.0075	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	AL	6/12/2007	VACUUM DEGASSER BOILER	95	MMBTU/H		0.0076	LB/MMBTU

TABLE E-10
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER (TPM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	Use of Natural Gas, Good Combustion Practices	0.008	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		0.008	LB/MMBTU
OH-0375	LONG RIDGE ENERGY GENERATION LLC -	OH	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Low sulfur fuel	0.01	LB/MMBTU
*WY-0075	CHEYENNE PRAIRIE GENERATING STATION	WY	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	good combustion practices	0.0175	LB/MMBTU
OH-0323	TITAN TIRE CORPORATION OF	OH	6/5/2008	BOILER	50.4	MMBTU/H		0.02	LB/MMBTU
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Boiler less than 100 MMBtu/hr	51.9	mmcubic ft/year	use of natural gas a clean fuel	0.0364	LB/MMBTU
*FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	60 MMBtu/hour Auxiliary Boiler	60	MMBtu/hour	Clean fuels		
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	99.8 MMBtu/hr auxiliary boiler	99.8	MMBtu/hr	Clean fuels		
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL		
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Auxiliary Boiler, 99.8 MMBtu/hr	99.8	MMBtu/hr	Use of clean fuels		
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	AUXILIARY BOILER	35	MMBTU/H	OPERATIONAL RESTRICTION OF 500 HR/YR, USE PUC QUALITY NATURAL GAS		

TABLE E-11
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Pipeline quality natural gas	0.0005	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	AUXILIARY BOILER	29.4	MMBTU/H	LOW SULFUR FUEL	0.0005	LB/MMBTU
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	7/11/2006	POWER STEAM BOILER	93	MMBTU/H		0.0005	LB/MMBTU
OH-0350	REPUBLIC STEEL	OH	7/18/2012	Steam Boiler	65	MMBtu/H		0.0006	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, VACUUM DEGASSER	88.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0006	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, PICKLE LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0006	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Combustion of Natural gas and Good Combustion Practice	0.0006	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0006	LB/MMBTU
*WI-0283	AFE, INC. â€“LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Good Combustion Practices and the Use of Pipeline Quality Natural Gas	0.0006	LB/MMBTU
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	WI	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Good Combustion Practices and The Use of Pipeline Quality Natural Gas	0.0006	LB/MMBTU
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS	0.0006	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT FL01	14.34	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA03	31.38	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP01	35.4	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP03	33.48	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT CP26	24	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU
SC-0112	NUCOR STEEL - BERKELEY	SC	5/5/2008	VACUUM DEGASSER BOILER	50.21	MMBTU/H	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.0006	LB/MMBTU
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	8/17/2007	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.9	MMBTU each		0.0006	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	AL	6/12/2007	VACUUM DEGASSER BOILER	95	MMBTU/H		0.0006	LB/MMBTU
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	5/3/2007	BOILER (2), NATURAL GAS	20.4	MMBTU/H		0.0006	LB/MMBTU
AR-0090	NUCOR STEEL, ARKANSAS	AR	4/3/2006	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH		0.0006	LB/MMBTU
OK-0129	CHOUTEAU POWER PLANT	OK	1/23/2009	AUXILIARY BOILER	33.5	MMBTU/H	LOW SULFUR FUEL	0.0009	LB/MMBTU

TABLE E-11
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NV-0044	HARRAH'S OPERATING COMPANY, INC.	NV	1/4/2007	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	USE OF NATURAL GAS AS THE ONLY FUEL	0.0010	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Auxiliary Boiler	40	MMBTU/H		0.0011	LB/MMBTU
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Auxiliary Boiler (B001)	99	MMBTU/H	natural gas/ultra low sulfur diesel	0.0014	LB/MMBTU
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Pipeline quality natural gas	0.0015	LB/MMBTU
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	low sulfur fuel	0.0015	LB/MMBTU
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Low sulfur fuel	0.0015	LB/MMBTU
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler firing natural gas	687	MMCFT/YR	Use of natural gas a low sulfur fuel	0.0015	LB/MMBTU
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Auxiliary Boiler	80	MMBTU/H		0.0015	LB/MMBTU
NV-0047	NELLIS AIR FORCE BASE	NV	2/26/2008	BOILERS/HEATERS - NATURAL GAS-FIRED			USE OF PIPELINE-QUALITY NATURAL GAS	0.0015	LB/MMBTU
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL USED BY THE UNIT.	0.0015	LB/MMBTU
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	Good combustion practices and the use of pipeline quality natural gas.	0.0018	LB/MMBTU
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Good combustion practices and the use of pipeline quality natural gas.	0.0018	LB/MMBTU
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Commercial/Institutional size boilers less than 100 MMBtu/hr	2000	hours/year	Use of natural gas	0.0018	LB/MMBTU
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	AUXILIARY BOILER	40	MMBTU/H		0.0021	LB/MMBTU
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	FUEL SPECIFICATIONS	0.0022	LB/MMBTU
OK-0135	PRYOR PLANT CHEMICAL	OK	2/23/2009	BOILERS #1 AND #2	80	MMBTU/H		0.0025	LB/MMBTU
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	5/16/2006	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0026	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	8/20/2009	BOILER - UNIT BA01	16.8	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS.	0.0042	LB/MMBTU
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Auxiliary Boiler, 99.8 MMBtu/hr	99.8	MMBtu/hr	Use of low-sulfur gas	0.0056	LB/MMBTU
FL-0335	SUWANNEE MILL	FL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46	MMBTU/H	Good Combustion Practice	0.0056	LB/MMBTU
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	99.8	MMBTU/H		0.0056	LB/MMBTU
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Boiler less than 100 MMBtu/hr	51.9	mmcubic ft/year	use of natural gas a clean fuel and a low sulfur fuel	0.0132	LB/MMBTU

TABLE E-11
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	40	MMBTU/H	Good combustion practice to ensure complete combustion.	0.0140	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Fuel total sulfur content will be less than or equal to 5 grains/100 dscf.	0.0140	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.2	MMBTU/H	Good combustion practice to ensure complete combustion.	0.0140	LB/MMBTU
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010	EQT0323 - Boiler 401F	99	MMBTU/H	Natural gas or Refinery Fuel Gas with H2S <=100 ppv (annual average)	0.0257	LB/MMBTU
*FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	60 MMBtu/hour Auxiliary Boiler	60	MMBtu/hour	Limited sulfur content in natural gas		
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	99.8 MMBtu/hr auxiliary boiler	99.8	MMBtu/hr	Clean fuels		
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING LOW SULFUR FUEL	0.128	LB/H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	AUXILIARY BOILER	4000	H/YR	USE OF NATURAL GAS A CLEAN BURNING LOW SULFUR FUEL	0.128	LB/H
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	BOILERS	5	MMBTU/H	COMBUSTION OF NATURAL GAS AND PROPANE.		

TABLE E-12
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2e and CO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AL-0231	NUCOR DECATUR LLC	AL	6/12/2007	VACUUM DEGASSER BOILER	95	MMBTU/H		0.061	lb/MMBtu
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGAUXBOILERS: Two auxiliary boilers <100 MMBTU/H heat input each	100	MMBTU/H heat input each	Efficient combustion; energy efficiency.	114.5	lb/MMBtu
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WV	6/14/2018	WH-1 - Boiler	8.72	mmBtu/hr	Limited to natural gas; and tune-up the boiler once every five years.	117.0	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, PICKLE LINE	0		GOOD OPERATING PRACTICES MINIMUM BOILER EFFICIENCY 75%	117	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		GOOD OPERATING PRACTICES MINIMUM BOILER EFFICIENCY 75%	117	lb/MMBtu
*AR-0159	BIG RIVER STEEL LLC	AR	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		GOOD OPERATING PRACTICES MINIMUM BOILER EFFICIENCY 75%	117	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, VACUUM DEGASSER	88.7	MMBTU/HR	GOOD OPERATING PRACTICES MINIMUM BOILER EFFICIENCY 75%	117	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER, PICKLE LINE	53.7	MMBTU/HR	GOOD OPERATING PRACTICES MINIMUM BOILER EFFICIENCY 75%	117	lb/MMBtu
AR-0155	BIG RIVER STEEL LLC	AR	11/7/2018	BOILER SN-26, GALVANIZING LINE	53.7	MMBTU/HR	GOOD OPERATING PRACTICES MINIMUM BOILER EFFICIENCY 75%	117	lb/MMBtu
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Clean fuels	117	lb/MMBtu
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Clean fuels	117	lb/MMBtu
*OK-0148	BUFFALO CREEK PROCESSING PLANT	OK	9/12/2012	Commercial/Institutional Boilers (<100 MMBTUH)	11.04	MMBTUH		117	lb/MMBtu
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	OPERATION AND MAINTENANCE PRACTICES; COMBUSTION TURNING; OXYGEN TRIM CONTROLS & ANALYZERS; ECONOMIZER;	117.0	lb/MMBtu
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	Use of Natural Gas	117.1	lb/MMBtu
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).	117.1	lb/MMBtu
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).	117.1	lb/MMBtu
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	99	MMBTU/H	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	117.1	lb/MMBtu
*WY-0075	CHEYENNE PRAIRIE GENERATING STATION	WY	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	good combustion practices and energy efficiency	117.1	lb/MMBtu
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	117.2	lb/MMBtu
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	117.2	lb/MMBtu
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		117.6	lb/MMBtu
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		117.6	lb/MMBtu

TABLE E-12
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2e and CO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0379	PETMIN USA INCORPORATED	OH	2/6/2019	Startup boiler (B001)	15.17	MMBTU/H	Good combustion practices and the use of natural gas	117.6	lb/MMBtu
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Auxillary Boiler	99	MMBtu/H		117.9	lb/MMBtu
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUAUXBOILER (Auxiliary boiler)	83.5	MMBTU/H	Good combustion practices.	118.3	lb/MMBtu
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	95	MMBTU/H	Good combustion practices	118.4	lb/MMBtu
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILERA)	55	MMBTU/H	Good combustion practices	118.4	lb/MMBtu
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.2	MMBTU/H	Good combustion practice to ensure complete combustion.	118.5	lb/MMBtu
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	40	MMBTU/H	Good combustion practice to ensure complete combustion.	118.5	lb/MMBtu
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Auxiliary Boiler	80	MMBTU/H		119	lb/MMBtu
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Auxiliary Boiler (B001)	99	MMBTU/H	Good combustion controls, natural gas combustion, and ultra low sulfur diesel	120	LB/MMBTU
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	MI	3/24/2017	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B,	3	MMBTU/H	Use of pipeline quality natural gas and energy efficiency measures.	139.3	lb/MMBtu
*AL-0307	ALLOYS PLANT	AL	10/9/2015	2 CALP LINE BOILERS	24.59	MMBTU/H		158.7	lb/MMBtu
WI-0266	GREEN BAY PACKAGING, INC. - SHIPPING CONTAINER DIVISION	WI	9/6/2018	Natural gas-fied boiler (Boiler B01)	35	mmBtu/hr	Good combustion practices, use only natural gas, equip with Low NOx burners and flue gas recirculation		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Energy efficiency measures, use of natural gas.		
*WI-0283	AFE, INC. â€"LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation, Good Combustion Practices and the Use of Pipeline Quality Natural Gas		
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY	WI	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices and the Use of Pipeline Quality Natural Gas.		
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Good combustion practices and pipeline quality natural gas		
OH-0377	HARRISON POWER	OH	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Good combustion practices and pipeline quality natural gas		
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL	OH	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Natural gas as the sole fuel		
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	use of natural gas, good combustion controls		
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Good combustion controls/natural gas combustion		
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Auxiliary Boiler, 99.8 MMBtu/hr	99.8	MMBtu/hr	Use of natural gas only		
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Good combustion practices and use of low carbon fuel		

TABLE E-12
NATURAL GAS FIRED BOILERS, LESS THAN 100 MMBTU/HR, PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2e and CO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*AL-0307	ALLOYS PLANT	AL	10/9/2015	PACKAGE BOILER	17.5	MMBTU/H			
OK-0164	MIDWEST CITY AIR DEPOT	OK	1/8/2015	Heaters/Boilers	0	MMBTUH	1. Use pipeline-quality natural gas. 2. Good Combustion Practices.		
*OH-0359	DTE MARIETTA	OH	3/31/2014	Backup Boilers (B001, B002)	96.5	MMBTU/H	Annual tune-ups, operating and maintenance practices.		
AL-0282	LENZING FIBERS, INC.	AL	1/22/2014	Natural Gas Fired Boilers (3)	100	mm btu/hr	Good combustion practices		
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Auxiliary Boiler	40	MMBTU/H			
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices.		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	AUXILIARY BOILER	40	MMBTU/H			
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	BOILERS	5	MMBTU/H	CONTROL METHOD FOR CO2E: GOOD DESIGN AND COMBUSTION PRACTICES.		

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	TX	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.02	g/hp-hr
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATOR SN-62	625	HP	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.30	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	500	H/YR	Certified engines, limited operating hours	0.99	g/hp-hr
CA-1217	BEA SAN DIEGO SHIP REPAIR	CA	8/23/2012	Internal Combustion Engine - 450 bhp	450	bhp		1.34	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	3.25	MMBTU/H		1.40	g/hp-hr
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	380 HP Diesel Fired Pump Engine	2.3	MMBTU/hr	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	2.20	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.24	g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)	Complying with 40 CFR 60 Subpart IIII	2.24	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP	Purchased certified to the standards in NSPS Subpart IIII	2.57	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.60	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Fire Pump Engine - 460 BHP	0			2.60	g/hp-hr
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Fire Pump	0			2.60	g/hp-hr
*AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Good Combustion Practices	2.76	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Fire Pump	14	GAL/H	good combustion practices	2.80	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.83	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.83	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.83	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.83	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Fire Pump	0			2.85	g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Generator	0			2.85	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	2.86	g/hp-hr
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	2.91	g/hp-hr
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Firewater Pump Engine	420	horsepower		2.98	g/hp-hr
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	State of the art combustion design.	2.98	g/hp-hr
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Good combustion practices and NSPS IIII	2.98	g/hp-hr
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Good combustion practices and NSPS Subpart IIII	2.98	g/hp-hr
*MI-0434	FLAT ROCK ASSEMBLY PLANT	MI	3/22/2018	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	500	KW	Good combustion practices.	2.98	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	305	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	2.98	g/hp-hr
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Low-emitting fuel and certified engine	2.98	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED FIRE PUMP ENGINE	300	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR DIESEL FUEL AND GOOD COMBUSTION PRACTICES	2.98	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	FIRE PUMP	500	HP	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	2.98	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	757	HP	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	2.98	g/hp-hr
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	EMERGENCY IC ENGINE	182	HP		2.98	g/hp-hr
LA-0251	FLOPAM INC. FACILITY	LA	4/26/2011	Small Generator Engine	193	hp		2.98	g/hp-hr
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	250 Kw Emergency Generator	0		Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP	2.98	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUFIREPUMP in FGRICE (Diesel fire pump engine)	500	H/YR	Certified engines. Limited operating hours.	2.98	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Dieself fire pump engine (EUFIREPUMP in FGRICE)	500	H/YR	Certified engines, limited operating hours.	2.98	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual	3.00	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	3.00	g/hp-hr
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	3.00	g/hp-hr
*MI-0434	FLAT ROCK ASSEMBLY PLANT	MI	3/22/2018	EUFIREPUMPENGS (2 emergency fire pump engines)	250	BHP	Good combustion practices.	3.00	g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	1.66	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	3.00	g/hp-hr
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	500	H/YR	Good combustion practices.	3.00	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Fire Pump Engine	0			3.00	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	282	HP	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	3.00	g/hp-hr
*KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Compression ignition RICE emergency fire pump	197	HP		3.00	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine	15	gal/hr		3.00	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Fire Pump Engine	251	HP		3.00	g/hp-hr
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	350	HP	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3.00	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	350	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3.00	g/hp-hr
IN-0185	MAG PELLET LLC	IN	4/24/2014	DIESEL FIRE PUMP	300	HP		3.00	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	300	HP	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION	3.00	g/hp-hr
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	477	HP	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3.00	g/hp-hr
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Fire Pump Engine	2.7	MMBTU/H		3.00	g/hp-hr
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	3.00	g/hp-hr
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.	3.00	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	371	BHP, EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	3.00	g/hp-hr
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	600 HP Emergency Equipment	0		See Pollutant Notes.	3.00	g/hp-hr
MI-0400	WOLVERINE POWER	MI	6/29/2011	Fire Pump	420	HP		3.00	g/hp-hr
LA-0251	FLOPAM INC. FACILITY	LA	4/26/2011	Fire Pump Engines - 2 units	444	hp		3.00	g/hp-hr
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	FL	12/23/2010	Emergency Diesel Fire Pump, One 600 HP	0			3.00	g/hp-hr
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	Two emergency diesel firewater pump engines	250	HP	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	3.00	g/hp-hr
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Emergency diesel fire pump	0			3.18	g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	EMERGENCY FIREWATER PUMP ENGINE	288	HP	EQUIPPED W/ A TURBOCHARGER AND AN INTERCOOLER/AFTERCOOLER	3.40	g/hp-hr
CA-1221	PACIFIC BELL	CA	12/5/2011	ICE:Emergency-Compression Ignition	3634	bhp	Tier 2 certified and 50 hr/yr for M&T limit	3.50	g/hp-hr
*WI-0291	GRAYMONT WESTERN LIME-EDEN	WI	1/28/2019	P04 Emergency Diesel Generator	0.22	mmBTU/hr	Good Combustion Practices	3.50	g/hp-hr
CA-1220	SAN DIEGO INTERNATIONAL AIRPORT	CA	10/3/2011	ICE:Emergency-Compression Ignition	1881	BHP	Tier 2 certified and 50 hr/y M&T limit	3.90	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H		3.95	g/hp-hr
CA-1219	CITY OF SAN DIEGO PUD (PUMP STATION 1)	CA	7/9/2012	IC engine	2722	bhp	Tier 2 certified engine and 50 hr/yr for M&T	4.00	g/hp-hr
*TX-0671	PROJECT JUMBO	TX	12/1/2014	Engines	0		Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx	4.05	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	2250	KW	Purchased certified to the standards in NSPS Subpart IIII	4.18	g/hp-hr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	4.42	g/hp-hr
MI-0395	WARREN TECHNICAL CENTER	MI	7/13/2012	Nine (9) DRUPS Emergency Generators	3010	KW	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	4.46	g/hp-hr
MI-0394	WARREN TECHNICAL CENTER	MI	2/29/2012	Nine (9) DRUPS Emergency Generators	3010	KW	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	4.46	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	4.46	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	4.46	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	B-HP	GOOD COMBUSTION PRACTICES	4.46	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Emergency Generator	142	GAL/H	good combustion practices	4.47	g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	650	horsepower	Compliance with NSPS Subpart IIII	4.61	g/hp-hr
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	4.63	g/hp-hr
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	4.63	g/hp-hr
WV-0027	INWOOD	WV	9/15/2017	Emergency Generator - ESDG14	900	bhp	Engine Design	4.77	g/hp-hr
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Emergency Engine	1500	kW		4.77	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and will be NSPS compliant.	4.77	g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	6000	HP	Good combustion practices and will be NSPS compliant.	4.77	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and will be NSPS compliant.	4.77	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	6000	HP	Good combustion practices and will be NSPS compliant.	4.77	g/hp-hr
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2	MW	State of the art combustion design.	4.77	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	4.77	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS IIII requirements.	4.77	g/hp-hr
*MI-0434	FLAT ROCK ASSEMBLY PLANT	MI	3/22/2018	EUENGINE01 through EUENGINE08	3633	BHP	Good combustion practices.	4.77	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices and meeting NSPS IIII requirements.	4.77	g/hp-hr
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	0		Good Combustion Practices/Maintenance	4.77	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY GENERATOR	1490	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.77	g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)	Complying with 40 CFR 60 Subpart IIII	4.77	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED AUXILIARY (EMERGENCY) ENGINES (TWO)	1500	KW	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.77	g/hp-hr
LA-0272	AMMONIA PRODUCTION FACILITY	LA	3/27/2013	EMERGENCY DIESEL GENERATOR (2205-B)	1200	HP	Compliance with 40 CFR 60 Subpart IIII; good combustion practices.	4.77	g/hp-hr
AK-0076	POINT THOMSON PRODUCTION FACILITY	AK	8/20/2012	Combustion of Diesel by ICEs	1750	kW		4.77	g/hp-hr
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	EMERGENCY IC ENGINE	2683	HP		4.77	g/hp-hr
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	2000 KW Emergency Equipment	0		See Pollutant Notes.	4.77	g/hp-hr
LA-0251	FLOPAM INC. FACILITY	LA	4/26/2011	Large Generator Engines (17 units)	0			4.77	g/hp-hr
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	FL	12/23/2010	Emergency Generators, Two 2682 HP EA	0			4.77	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	500	H/YR	Certified engines, limited operating hours.	4.78	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	500	H/YR	Certified engines, limited operating hours.	4.78	g/hp-hr
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	2000 KW Diesel Fired Emergency Generator Engine	20.4	MMBTU/hr	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	4.78	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	4.80	g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	4.80	g/hp-hr
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.80	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Generator Engines	0			4.80	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Generator 1	2584	HP	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	4.80	g/hp-hr
LA-0292	HOLBROOK COMPRESSOR STATION	LA	1/22/2016	Emergency Generators No. 1 & No. 2	1341	HP	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII	4.80	g/hp-hr
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Emergency Camp Generators	2695	hp		4.80	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Emergency Generator	2015.7	HP		4.80	g/hp-hr
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	EMERGENCY GENERATOR	1300	HP	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.80	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	EMERGENCY GENERATOR	1550	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 1	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 2	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 1	751	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 2	751	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY GENERATOR	1500	KW	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION	4.80	g/hp-hr
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY GENERATOR 1	2250	KW	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.80	g/hp-hr
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Emergency Engine/Generator	7.4	MMBTU/H		4.80	g/hp-hr
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	1000	kW	Good combustion practices	4.80	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	1006	HP EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.80	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY DIESEL GENERATOR	2012	HP	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.80	g/hp-hr
MI-0402	SUMPTER POWER PLANT	MI	11/17/2011	Diesel fuel-fired combustion engine (RICE)	732	HP	Good combustion practices	4.85	g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Emergency Generator	0			4.93	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	EMERGENCY GENERATOR-ENGINE	0			4.93	g/hp-hr
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Emergency Generator	0			4.93	g/hp-hr
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	182	BHP	utilize efficient combustion/design technology	4.98	g/hp-hr
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	1341	HP	COMBUSTION CONTROL	4.99	g/hp-hr
MI-0394	WARREN TECHNICAL CENTER	MI	2/29/2012	Four (4) Emergency Generators	2280	KW	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.17	g/hp-hr
MI-0418	WARREN TECHNICAL CENTER	MI	1/14/2015	Four (4) emergency engines in FG-BACKUPGENS	2710	KW	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.32	g/hp-hr
MI-0395	WARREN TECHNICAL CENTER	MI	7/13/2012	Four (4) Emergency Generators	2500	KW	No add-on control, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.32	g/hp-hr
DC-0009	BLUE PLAINS ADVANCED WASTEWATER TREATEMENT PLANT	DC	3/15/2012	Diesel Emergency Generator	2682	hp		5.39	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	0			5.45	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY ENGINE 1 THRU 8	29	HP	PURCHASE OF CERTIFIED ENGINE.	5.59	g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	5.92	g/hp-hr
MI-0418	WARREN TECHNICAL CENTER	MI	1/14/2015	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	3490	KW	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.96	g/hp-hr
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	AL	7/22/2014	DIESEL FIRED EMERGENCY GENERATOR	800	HP		6.80	g/hp-hr
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	250	hp		6.86	g/hp-hr
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	PA	6/1/2012	650-KW BACKUP DIESEL GENERATOR	45.8	GAL/H		6.90	g/hp-hr
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	PA	6/1/2012	400-KW DIESEL EMERGENCY GENERATOR	29.2	GAL/H		6.90	g/hp-hr
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Caterpillar C18DITA Diesel Engine Generator	900	BHP	utilize efficient combustion/design technology	7.06	g/hp-hr
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	EMERGENCY FIRE PUMP ENGINE	0		GOOD COMBUSTION PRACTICES	9.50	g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	150	hp		14.06	g/hp-hr
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	FL	9/16/2014	Emergency Diesel Engine	3300	hp	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure		g/hp-hr
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				g/hp-hr
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				g/hp-hr
*AL-0318	TALLADEGA SAWMILL	AL	12/18/2017	250 Hp Emergency CI, Diesel-fired RICE	0				g/hp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	firewater pump engines (8 units)	460	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	emergency generator engines (6 units)	3353	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Fire Water Diesel Pump No. 3 Engine	600	hp	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Fire Water Diesel Pump No. 4 Engine	600	hp	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Standby Generator No. 9 Engine	400	hp	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Emergency Generator Engines (4 units)	0		complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		g/hp-hr
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Firewater pump Engines (4 units)	896	hp (each)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel Firewater pump engines (6 units)	425	hp	complying with 40 CFR 63 subpart ZZZZ		g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel emergency generator engine - EGEN	350	hp	complying with 40 CFR 63 subpart ZZZZ		g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY GENERATOR DIESEL	0	100 H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY DIESEL FIRE PUMP	100	H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		g/hp-hr
LA-0305	LAKE CHARLES METHANOL FACILITY	LA	6/30/2016	Diesel Engines (Emergency)	4023	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	0		Good Combustion Practices/Maintenance		g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	44	H/YR	use of ultra low sulfur diesel a clean burning fuel.		g/hp-hr

TABLE E-13
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Emergency Diesel Fire Pump	100	H/YR	use of ULSD a clean burning fuel, and limited hours of operation		g/hp-hr
TX-0706	NATURAL GAS FRACTIONATION	TX	1/23/2014	Emergency Engines	0				g/hp-hr
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Generator	60	Gal/hr			g/hp-hr
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Firewater Pump	16	Gal/hr			g/hp-hr
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Emergency Generator	200	H/YR	use of ultra low sulfur diesel (ULSD) a clean fuel		g/hp-hr
WY-0071	SINCLAIR REFINERY	WY	10/15/2012	Emergency Air Compressor	400	hp	EPA Tier 3 Rated Diesel Engine		g/hp-hr
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Diesel Emergency Generator (EP15)	839	hp	EPA Tier 2 rated		g/hp-hr
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Diesel Fire Pump Engine (EP16)	327	hp	EPA Tier 3 rated		g/hp-hr
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Emergency Generator	100	H/YR	Use of ULSD diesel oil		g/hp-hr
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	TWO (2) EMERGENCY GENERATORS	1341	HORSEPOWER, EACH	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION		g/hp-hr
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	THREE (3) FIREWATER PUMP ENGINES	575	HORSEPOWER, EACH	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION		g/hp-hr
OK-0145	BROKEN BOW OSB MILL	OK	6/25/2012	Emerg Diesel Gen, Fire Pump, Rail Steam Gen, Air Makeup Units	0				g/hp-hr
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - Development Driller 1	2229	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler		g/hp-hr
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - C.R. Luigs	2064	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler		g/hp-hr
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	FL	5/15/2012	Emergency Electrical Generator	1100	hp	Use of good combustion and maintenance practices based on the current manufacturer's specifications for this engine.		g/hp-hr
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		g/hp-hr
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Fire Pump Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		g/hp-hr
FL-0327	ANADARKO - PHEONIX PROSPECT	FL	6/13/2011	Emergency Engine	0		Limited use of 24 hours/week and recordkeeping of operation.		g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	1341	HP	COMBUSTION CONTROL.	0.0003	g/hp-hr
TX-0799	BEAUMONT TERMINAL	TX	6/8/2016	Fire pump engines	0		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	0.006	g/hp-hr
TX-0799	BEAUMONT TERMINAL	TX	6/8/2016	EMERGENCY ENGINES	0		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	0.007	g/hp-hr
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	TX	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.013	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	EMERGENCY GENERATOR-ENGINE	0			0.1	g/hp-hr
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Emergency Generator	0			0.1	g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	0.2	g/hp-hr
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Emergency Generator	0			0.3	g/hp-hr
MI-0402	SUMPTER POWER PLANT	MI	11/17/2011	Diesel fuel-fired combustion engine (RICE)	732	HP	Good combustion practices	0.3	g/hp-hr
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	EMERGENCY FIREWATER PUMP ENGINE	288	HP	EQUIPPED W/ A TURBOCHARGER AND AN INTERCOOLER/AFTERCOOLER	0.4	g/hp-hr
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Emergency generator	0		Good combustion practice.	0.5	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine	15	gal/hr		0.5	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Fire Pump Engine - 460 BHP	0			0.5	g/hp-hr
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Fire Pump	0			0.5	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.5	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	0			0.6	g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	650	horsepower	Compliance with NSPS Subpart IIII	0.6	g/hp-hr
LA-0251	FLOPAM INC. FACILITY	LA	4/26/2011	Fire Pump Engines - 2 units	444	hp	good equipment design and proper combustion practices	0.7	g/hp-hr
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	Diesel Fire water pump 376 bhp	500	h/yr	good combustion practices	0.7	g/hp-hr
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Caterpillar C18DITA Diesel Engine Generator	900	BHP	utilize efficient combustion/design technology	0.9	g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	182	BHP	utilize efficient combustion/design technology	1.3	g/hp-hr
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	EMERGENCY FIRE PUMP ENGINE	0		GOOD COMBUSTION PRACTICES	2.0	g/hp-hr
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	150	hp		2.3	g/hp-hr
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	250	hp		2.3	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H		2.3	g/hp-hr
*AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Good Combustion Practices	2.5	g/hp-hr
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	AL	7/22/2014	DIESEL FIRED EMERGENCY GENERATOR	800	HP		2.5	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP	Purchased certified to the standards in NSPS Subpart IIII	2.6	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUFPRICE--A 315 HP diesel fueled emergency engine	2.5	MMBTU/H	Good combustion practices.	2.6	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual	2.6	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	2.6	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	2.6	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUFPRICE--A 315 HP diesel fueled emergency engine	2.5	MMBTU/H	Good combustion practices.	2.6	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.6	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.6	g/hp-hr
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	2.6	g/hp-hr
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	2.6	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	1.66	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.6	g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Generator 1	2584	HP	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	2.6	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	282	HP	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	2.6	g/hp-hr
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Emergency Camp Generators	2695	hp		2.6	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Emergency Generator	2015.7	HP		2.6	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	EMERGENCY GENERATOR	1550	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO MEET EMISSION LIMIT	2.6	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	2.6	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY GENERATOR	1500	KW	USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	300	HP	USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Fire Pump	0			2.6	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Generator	0			2.6	g/hp-hr
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY GENERATOR 1	2250	KW	USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR	2.6	g/hp-hr
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	477	HP	USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR	2.6	g/hp-hr
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Emergency diesel fire pump	0			2.6	g/hp-hr
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Emergency Engine/Generator	7.4	MMBTU/H		2.6	g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Fire Pump Engine	2.7	MMBTU/H		2.6	g/hp-hr
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	1000	kW	Good combustion practices.	2.6	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.	2.6	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	371	BHP, EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	2.6	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	1006	HP EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	2.6	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY DIESEL GENERATOR	2012	HP	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	2.6	g/hp-hr
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	600 HP Emergency Equipment	0		See Pollutant Notes.	2.6	g/hp-hr
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	EMERGENCY DIESEL GENERATOR	1250	HP	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	EMERGENCY FIRE PUMP	350	HP	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	FL	12/23/2010	Emergency Diesel Fire Pump, One 600 HP	0			2.6	g/hp-hr
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	Two emergency diesel firewater pump engines	250	HP	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	2.6	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	3.25	MMBTU/H		2.6	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Fire Pump Engine	251	HP		2.6	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	2250	KW	Purchased certified to the standards in NSPS Subpart IIII	2.6	g/hp-hr
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Firewater Pump Engine	420	horsepower		2.6	g/hp-hr
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Emergency Engine	1500	kW		2.6	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and will be NSPS compliant.	2.6	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	6000	HP	Good combustion practices and will be NSPS compliant.	2.6	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and will be NSPS compliant.	2.6	g/hp-hr
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	6000	HP	Good combustion practices and will be NSPS compliant.	2.6	g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2	MW	State of the art combustion design.	2.6	g/hp-hr
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	State of the art combustion design.	2.6	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.6	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS IIII requirements.	2.6	g/hp-hr
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	Two 3300 kW emergency generators	0		Certified engine	2.6	g/hp-hr
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	Emergency Fire Pump Engine (422 hp)	0		Certified engine	2.6	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	500	H/YR	Good design and combustion practices.	2.6	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	500	H/YR	Good design and combustion practices.	2.6	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUFIREPUMP in FGRICE (Diesel fire pump engine)	500	H/YR	Good design and combustion practices.	2.6	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.6	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	500	H/YR	Good design and combustion practices.	2.6	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Dieself fire pump engine (EUFIREPUMP in FGRICE)	500	H/YR	Good design and combustion practices.	2.6	g/hp-hr
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	0		Good Combustion Practices/Maintenance	2.6	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Three 3300-kW ULSD emergency generators	0		Use of clean engine	2.6	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	One 422-hp emergency fire pump engine	0		Use of clean engine technology	2.6	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY GENERATOR	1490	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	305	HP	USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Low-emitting fuel and certified engine	2.6	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED AUXILIARY (EMERGENCY) ENGINES (TWO)	1500	KW	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED FIRE PUMP ENGINE	300	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR DIESEL FUEL AND GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Emergency fire pump engine (300 HP)	29	MMBTU/H	Good combustion practice.	2.6	g/hp-hr
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATOR SN-62	625	HP	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	2.6	g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Emergency Generators	180	GAL/H	good combustion practices	2.6	g/hp-hr
LA-0272	AMMONIA PRODUCTION FACILITY	LA	3/27/2013	EMERGENCY DIESEL GENERATOR (2205-B)	1200	HP	Compliance with 40 CFR 60 Subpart IIII; good combustion practices.	2.6	g/hp-hr
*VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	Emergency diesel generator- 2200 kW	500	hrs/yr	good combustion practices	2.6	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Emergency Generator	142	GAL/H	good combustion practices	2.6	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Fire Pump	14	GAL/H	good combustion practices	2.6	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	FIRE PUMP	500	HP	ENGINES CERTIFIED TO MEET NSPS, SUBPART IIII. HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR FOR MAINTENANCE AND TESTING.	2.6	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	757	HP	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	2.6	g/hp-hr
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	EMERGENCY IC ENGINE	2683	HP		2.6	g/hp-hr
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	EMERGENCY IC ENGINE	182	HP		2.6	g/hp-hr
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	2000 KW Emergency Equipment	0		See Pollutant Notes.	2.6	g/hp-hr
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	FL	12/23/2010	Emergency Generators, Two 2682 HP EA	0			2.6	g/hp-hr
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	250 Kw Emergency Generator	0		Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP	2.6	g/hp-hr
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	2.6	g/hp-hr
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	2.6	g/hp-hr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Generator Engines	0			2.6	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Fire Pump Engine	0			2.6	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	B-HP	GOOD COMBUSTION PRACTICES	2.6	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 1	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	2.6	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 2	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	2.6	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 1	751	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	2.6	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 2	751	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	2.6	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	350	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO MEET EMISSION LIMIT	3.0	g/hp-hr
*LA-0306	TOPCHEM POLLOCK, LLC	LA	12/20/2016	Pump Engines DFP-16-1 (EQT036)	225	horsepower	Meet NSPS Subpart IIII Limitations and Good Combustion Practices	3.1	g/hp-hr
*LA-0306	TOPCHEM POLLOCK, LLC	LA	12/20/2016	Pump Engine DFP-16-2 (EQT037)	225	horsepower	Meet NSPS Subpart IIII Limitations and Good Combustion Practices	3.1	g/hp-hr
*LA-0306	TOPCHEM POLLOCK, LLC	LA	12/20/2016	Genenerator Engine DEG-16-1 (EQT035)	460	horsepower	Meet NSPS Subpart IIII Limitations and Good Combustion Practices	3.1	g/hp-hr
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	500	H/YR	Good combustion practices.	3.7	g/hp-hr
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	3.7	g/hp-hr
*WI-0291	GRAYMONT WESTERN LIME-EDEN	WI	1/28/2019	P04 Emergency Diesel Generator	0.22	mmBTU/hr	Good Combustion Practices	3.7	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY ENGINE 1 THRU 8	29	HP	PURCHASE OF CERTIFIED ENGINE. HOURS OF OPERATION LIMITED TO 100 HOURS FOR MAINTENANCE AND TESTING.	4.1	g/hp-hr
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				g/hp-hr
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				g/hp-hr
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Compliance with 40 CFR 60 Subpart IIII		g/hp-hr
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Compliance with 40 CFR 60 Subpart IIII		g/hp-hr
*AL-0318	TALLADEGA SAWMILL	AL	12/18/2017	250 Hp Emergency CI, Diesel-fired RICE	0				g/hp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	firewater pump engines (8 units)	460	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	emergency generator engines (6 units)	3353	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Fire Water Diesel Pump No. 3 Engine	600	hp	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Fire Water Diesel Pump No. 4 Engine	600	hp	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Standby Generator No. 9 Engine	400	hp	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Emergency Generator Engines (4 units)	0		complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		g/hp-hr
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Firewater pump Engines (4 units)	896	hp (each)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel Firewater pump engines (6 units)	425	hp	complying with 40 CFR 63 subpart ZZZZ		g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel emergency generator engine - EGEN	350	hp	complying with 40 CFR 63 subpart ZZZZ		g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY GENERATOR DIESEL	0	100 H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation (<= 100 H/YR)		g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY DIESEL FIRE PUMP	100	H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		g/hp-hr
LA-0305	LAKE CHARLES METHANOL FACILITY	LA	6/30/2016	Diesel Engines (Emergency)	4023	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	44	H/YR	use of ultra low sulfur diesel oil a clean burning fuel		g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Emergency Diesel Fire Pump	100	H/YR	use of ULSD a clean burning fuel, and limited hours of operation		g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	FL	9/16/2014	Emergency Diesel Engine	3300	hp	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure		g/hp-hr
MS-0092	EMBERCLEAR GTL MS	MS	5/8/2014	firewater pumps, diesel	325	HP, EACH			g/hp-hr
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Generator	60	Gal/hr			g/hp-hr
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Firewater Pump	16	Gal/hr			g/hp-hr
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Fire pump	0		Good combustion practice.		g/hp-hr

TABLE E-14
DIESEL FUEL FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR CARBON MONOXIDE (CO)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Emergency Generator	200	H/YR			g/hp-hr
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Diesel Emergency Generator (EP15)	839	hp	EPA Tier 2 rated		g/hp-hr
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Diesel Fire Pump Engine (EP16)	327	hp	EPA Tier 3 rated		g/hp-hr
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Emergency Generator	100	H/YR	Use of ULSD oil		g/hp-hr
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	TWO (2) EMERGENCY GENERATORS	1341	HORSEPOWER, EACH	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION		g/hp-hr
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	THREE (3) FIREWATER PUMP ENGINES	575	HORSEPOWER, EACH	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION		g/hp-hr
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - Development Driller 1	2229	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler		g/hp-hr
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - C.R. Luigs	2064	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler		g/hp-hr
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		g/hp-hr
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Fire Pump Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		g/hp-hr

TABLE E-15
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	0.003	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	EMERGENCY GENERATOR-ENGINE	0			0.01	g/hp-hr
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Emergency Generator	0			0.01	g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	0.01	g/hp-hr
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Caterpillar C18DITA Diesel Engine Generator	900	BHP	utilize efficient combustion/design technology	0.02	g/hp-hr
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Emergency Generator	0			0.02	g/hp-hr
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	EMERGENCY FIRE PUMP ENGINE	0		GOOD COMBUSTION PRACTICES	0.05	g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	650	horsepower	Compliance with NNSPS Subpart IIII	0.09	g/hp-hr
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	0.09	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.10	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Fire Pump Engine - 460 BHP	0			0.10	g/hp-hr
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Fire Pump	0			0.10	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine	15	gal/hr		0.12	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr

TABLE E-15
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0.14	g/hp-hr
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	0.14	g/hp-hr
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	State of the art combustion design.	0.15	g/hp-hr
OK-0164	MIDWEST CITY AIR DEPOT	OK	1/8/2015	Diesel-Fueled Fire Pump Engines	300	HP	1. Good Combustion Practices.	0.15	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Fire Pump	0			0.15	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Generator	0			0.15	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Fire Pump	14	GAL/H	good combustion practices	0.19	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	371	BHP, EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.20	g/hp-hr
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	TX	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.21	g/hp-hr
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Emergency diesel fire pump	0			0.22	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	0			0.22	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY DIESEL GENERATOR	2012	HP	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.23	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Emergency Generator	2015.7	HP		0.28	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H		0.28	g/hp-hr
LA-0292	HOLBROOK COMPRESSOR STATION	LA	1/22/2016	Emergency Generators No. 1 & No. 2	1341	HP	Good combustion practices consistent with the manufacturer's recommendations to maximize fuel efficiency and minimize emissions	0.28	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices.	0.29	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices.	0.29	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices	0.29	g/hp-hr

TABLE E-15
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0327	PERDUE GRAIN AND OILSEED, LLC	VA	7/12/2017	Emergency Generator	0			0.29	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Emergency Generator	142	GAL/H	good combustion practices	0.30	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Fire Pump Engine	251	HP		0.31	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	0.31	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	0.31	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	B-HP	GOOD COMBUSTION PRACTICES	0.31	g/hp-hr
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Emergency Camp Generators	2695	hp		0.32	g/hp-hr
TX-0799	BEAUMONT TERMINAL	TX	6/8/2016	Fire pump engines	0		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	0.32	g/hp-hr
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	1341	HP	COMBUSTION CONTROL.	0.32	g/hp-hr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	0.35	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP	Purchased certified to the standards in NSPS Subpart IIII	0.38	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	1006	HP EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.47	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	2250	KW	Purchased certified to the standards in NSPS Subpart IIII	0.59	g/hp-hr
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	182	BHP	utilize efficient combustion/design technology	0.77	g/hp-hr
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	EMERGENCY DIESEL GENERATOR	1250	HP	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	1.00	g/hp-hr
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	EMERGENCY FIRE PUMP	350	HP	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	1.00	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	1.66	MMBTU/H	Good combustion practices	1.12	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	3.25	MMBTU/H		1.12	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices.	1.13	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices	1.13	g/hp-hr
TX-0799	BEAUMONT TERMINAL	TX	6/8/2016	EMERGENCY ENGINES	0		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	1.13	g/hp-hr

TABLE E-15
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	150	hp		1.13	g/hp-hr
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	250	hp		1.13	g/hp-hr
*KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Compression ignition RICE emergency fire pump	197	HP		1.14	g/hp-hr
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	500	H/YR	Good combustion practices	1.29	g/hp-hr
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Good combustion practices and NSPS Subpart IIII	2.98	g/hp-hr
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Good combustion practices and NSPS Subpart IIII	2.98	g/hp-hr
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Emergency Generators	180	GAL/H	good combustion practices	2.98	g/hp-hr
SC-0159	US10 FACILITY	SC	7/9/2012	FIRE PUMPS, FIRE1, FIRE2, FIRE3	211	KW	BACT HAS BEEN DETERMINED TO BE COMPLIANCE WITH NSPS, SUBPART IIII, 40 CFR60.4202 AND 40 CFR60.4205.	2.98	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	FIRE PUMP	500	HP	CERTIFIED ENGINES THAT COMPLY WITH NSPS, SUBPART IIII. HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR FOR MAINTENANCE AND TESTING.	2.98	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	757	HP	PURCHASE ENGINES CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	2.98	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual	3.00	g/hp-hr
OK-0175	WILDHORSE TERMINAL	OK	6/29/2017	Emergency Use Engines <500 HP	0		Good combustion practices. Certified to meet EPA Tier 3 engine standards. Shall be limited to operate at no more than 500 hr/yr.	3.00	g/hp-hr
OK-0175	WILDHORSE TERMINAL	OK	6/29/2017	Emergency Use Engine less than or equal to 500 HP	0		Good combustion practices, certified to meet EPA Tier 3 engine standards. Gen-1, FP-1, and FP-2 shall be limited to operate no more than 500 hr/yr.	3.00	g/hp-hr
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	0		Good Combustion Practices/Maintenance	3.00	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	350	HP	USE ONLY ULSD, GOOD COMBUSTION PRACTICES, AND DESIGNED TO ACHIEVE EMISSION LIMIT	3.00	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	282	HP	Good combustion practices	3.01	g/hp-hr
*WI-0261	ENBRIDGE ENERGY - SUPERIOR TERMINAL	WI	6/12/2014	EG7 - Diesel Emergency Electric Generator w/ tank	197	BHP	NSPS engine [Tier 3 emergency engine]. EG7 Storage tank, conventional fuel oil storage tank, good operating practices; limiting leakage, spills. (FT01). Engine limited to 200 hours / year (total) and NSPS requirements.	3.75	g/hp-hr

TABLE E-15
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	0		Good Combustion Practices/Maintenance	4.77	g/hp-hr
SC-0159	US10 FACILITY	SC	7/9/2012	EMERGENCY GENERATORS, GEN1, GEN2	1000	KW	BACT HAS BEEN DETERMINED TO BE COMPLIANCE WITH NSPS, SUBPART IIII, 40 CFR60.4202 AND 40 CFR60.4205.	4.77	g/hp-hr
LA-0272	AMMONIA PRODUCTION FACILITY	LA	3/27/2013	EMERGENCY DIESEL GENERATOR (2205-B)	1200	HP	Compliance with 40 CFR 60 Subpart IIII; good combustion practices.	4.78	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Generator 1	2584	HP	Good combustion practices	4.80	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	4.80	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	4.80	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	EMERGENCY GENERATOR	1550	HP	USE ONLY ULSD, GOOD COMBUSTION PRACTICES, AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 1	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 2	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 1	751	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 2	751	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.80	g/hp-hr
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY ENGINE 1 THRU 8	29	HP	PURCHASE OF CERTIFIED ENGINES. HOURS OF OPERATION LIMITED TO 100 HOURS FOR MAINTENANCE AND TESTING.	5.59	g/hp-hr
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATOR SN-62	625	HP	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	14.17	g/hp-hr
*WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	WI	4/1/2019	P37 Diesel-Fired Emergency Fire Pump	0		Hours of Operation		g/hp-hr
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2	MW	State of the art combustion design.		g/hp-hr
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.		g/hp-hr
*AL-0318	TALLADEGA SAWMILL	AL	12/18/2017	250 Hp Emergency CI, Diesel-fired RICE	0				g/hp-hr
OK-0176	BPV GATHERING AND MARKETING CUSHING STATION	OK	7/19/2017	Emergency Generator	400	HP	Equipped with non-resettable hour meter. Fired with ultra-low sulfur diesel fuel (0.015 % or less by wt. sulfur.		g/hp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	firewater pump engines (8 units)	460	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	emergency generator engines (6 units)	3353	hp	Complying with 40 CFR 60 Subpart IIII		g/hp-hr

TABLE E-15
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0276	BATON ROUGE JUNCTION FACILITY	LA	12/15/2016	Fire Pump Engines (2 units)	700	hp	Comply with standards of NSPS Subpart IIII		g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel Firewater pump engines (6 units)	425	hp	complying with 40 CFR 63 subpart ZZZZ		g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel emergency generator engine - EGEN	350	hp	complying with 40 CFR 63 subpart ZZZZ		g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY GENERATOR DIESEL	0	100 H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY DIESEL FIRE PUMP	100	H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	44	H/YR	use of ULSD a clean burning fuel, and limited hours of operation		g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Emergency Diesel Fire Pump	100	H/YR	use of ULSD a clean burning fuel, and limited hours of operation		g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)	Complying with 40 CFR 60 Subpart IIII		g/hp-hr
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	FL	9/16/2014	Emergency Diesel Engine	3300	hp	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure		g/hp-hr
MS-0092	EMBERCLEAR GTL MS	MS	5/8/2014	firewater pumps, diesel	325	HP, EACH			g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY GENERATOR	1500	KW	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION		g/hp-hr
TX-0706	NATURAL GAS FRACTIONATION	TX	1/23/2014	Emergency Engines	0				g/hp-hr
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Generator	60	Gal/hr			g/hp-hr
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Firewater Pump	16	Gal/hr			g/hp-hr
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Emergency generator	0		Good combustion practice.		g/hp-hr
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Fire pump	0		Good combustion practice.		g/hp-hr
OK-0156	NORTHSTAR AGRI IND ENID	OK	7/31/2013	Fire Pump Engine	550	hp	Good Combustion		g/hp-hr
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.		g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY GENERATOR ULSD TANKS	550	GALLONS EACH	GOOD DESIGN AND OPERATING PRACTICES		g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY GENERATOR ULSD TANK	300	GALLONS	GOOD CUMBUSTION PRACTICE AND FUEL SPECIFICATION		g/hp-hr

TABLE E-15
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR VOLATILE ORGANIC COMPOUNDS (VOC)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Emergency Generator	200	H/YR	use of ULSD, a low sulfur clean fuel		g/hp-hr
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Emergency Generator	100	H/YR	Use of ULSD oil		g/hp-hr
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - Development Driller 1	2229	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler		g/hp-hr
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - C.R. Luigs	2064	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler		g/hp-hr
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		g/hp-hr
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Fire Pump Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		g/hp-hr

TABLE E-16
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATOR SN-62	625	HP	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.01	g/hp-hr
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATORS	1500	KW	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.01	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	0			0.025	g/hp-hr
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Emergency generator	0		Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.	0.03	g/hp-hr
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Emergency Generator	0			0.04	g/hp-hr
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	TX	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.05	g/hp-hr
MI-0402	SUMPTER POWER PLANT	MI	11/17/2011	Diesel fuel-fired combustion engine (RICE)	732	HP	Good combustion practices	0.05	g/hp-hr
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Caterpillar C18DITA Diesel Engine Generator	900	BHP	utilize efficient combustion/design technology	0.066	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.087	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine	15	gal/hr		0.11	g/hp-hr
*AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Clean Fuel and Good Combustion Practices	0.14	g/hp-hr
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Firewater Pump Engine	420	horsepower		0.15	g/hp-hr
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Emergency Engine	1500	kW		0.15	g/hp-hr
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2	MW	State of the art combustion design	0.15	g/hp-hr
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	State of the art combustion design	0.15	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.15	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Diesel particulate filter, good combustion practices and meeting NSPS IIII requirements.	0.15	g/hp-hr
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	Two 3300 kW emergency generators	0		Clean fuel	0.15	g/hp-hr
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	Emergency Fire Pump Engine (422 hp)	0		Certified engine	0.15	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	500	H/YR	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.15	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	500	H/YR	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.15	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUFIREPUMP in FGRICE (Diesel fire pump engine)	500	H/YR	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.15	g/hp-hr

TABLE E-16
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.15	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	500	H/YR	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.15	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Diesel fire pump engine (EUFIREPUMP in FGRICE)	500	H/YR	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.15	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Three 3300-kW ULSD emergency generators	0		Use of clean fuel	0.15	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	One 422-hp emergency fire pump engine	0		Use of clean fuel	0.15	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY GENERATOR	1490	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	305	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Low-emitting fuel and certified engine	0.15	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED AUXILIARY (EMERGENCY) ENGINES (TWO)	1500	KW	USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED FIRE PUMP ENGINE	300	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR DIESEL FUEL AND GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Emergency Generators	180	GAL/H	good combustion practices	0.15	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Emergency Generator	142	GAL/H	good combustion practices	0.15	g/hp-hr
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Fire Pump	14	GAL/H	good combustion practices	0.15	g/hp-hr
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	EMERGENCY IC ENGINE	2683	HP	USE ULTRA LOW SULFUR FUEL	0.15	g/hp-hr
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	EMERGENCY IC ENGINE	182	HP	USE ULTRA LOW SULFUR FUEL	0.15	g/hp-hr
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	2000 KW Emergency Equipment	0		See Pollutant Notes.	0.15	g/hp-hr
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	FL	12/23/2010	Emergency Generators, Two 2682 HP EA	0			0.15	g/hp-hr
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	250 Kw Emergency Generator	0		Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP & demonstrate compliance in accordance with the procedures	0.15	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the	0.15	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per	0.15	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per	0.15	g/hp-hr
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.15	g/hp-hr

TABLE E-16
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.15	g/hp-hr
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	g/hp-hr
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	g/hp-hr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	1.66	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.15	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Generator Engines	0			0.15	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Fire Pump Engine	0			0.15	g/hp-hr
*KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART	KS	3/31/2016	Compression ignition RICE emergency fire pump	197	HP		0.15	g/hp-hr
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	KS	7/14/2015	Emergency diesel engine	750	KW	Low sulfur fuel oil (<15 ppm sulfur)	0.15	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	EMERGENCY GENERATOR	1550	HP	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.15	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	350	HP	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.15	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IN-0185	MAG PELLET LLC	IN	4/24/2014	DIESEL FIRE PUMP	300	HP		0.15	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY GENERATOR	1500	KW	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	300	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE	PR	4/10/2014	Emergency Diesel Fire Pump	0			0.15	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE	PR	4/10/2014	Emergency Diesel Generator	0			0.15	g/hp-hr

TABLE E-16
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY GENERATOR 1	2250	KW	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND DESIGNED TO ACHIEVE	0.15	g/hp-hr
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	477	HP	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND DESIGNED TO ACHIEVE	0.15	g/hp-hr
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Emergency diesel fire pump	0		Use of Ultra low sulfur distillate oil	0.15	g/hp-hr
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	1000	kW	Good combustion practices.	0.15	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	B-HP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	0.15	g/hp-hr
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.	0.15	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	371	BHP, EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	1006	HP EACH	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	g/hp-hr
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY DIESEL GENERATOR	2012	HP	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	g/hp-hr
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	600 HP Emergency Equipment	0		See Pollutant Notes.	0.15	g/hp-hr
MI-0400	WOLVERINE POWER	MI	6/29/2011	Emergency generator	4000	HP		0.15	g/hp-hr
MI-0400	WOLVERINE POWER	MI	6/29/2011	Fire Pump	420	HP		0.15	g/hp-hr
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	FL	12/23/2010	Emergency Diesel Fire Pump, One 600 HP	0			0.15	g/hp-hr
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	Two emergency diesel firewater pump engines	250	HP	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	0.15	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	3.25	MMBTU/H		0.15	g/hp-hr
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	EMERGENCY FIRE PUMP ENGINE	0		GOOD COMBUSTION PRACTICES	0.16	g/hp-hr
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Emergency fire pump engine (300 HP)	29	MMBTU/H	Good combustion practice	0.2	g/hp-hr
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	500	H/YR	Good combustion practices.	0.22	g/hp-hr
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	0.22	g/hp-hr
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	182	BHP	utilize efficient combustion/design technology	0.25	g/hp-hr
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	AL	7/22/2014	DIESEL FIRED EMERGENCY GENERATOR	800	HP		0.32	g/hp-hr

TABLE E-16
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	IN	2/23/2018	Emergency Diesel Generators	250	hp		0.40	g/hp-hr
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	IN	2/23/2018	Emergency Diesel Generators	150	hp		1.00	g/hp-hr
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				
*AL-0318	TALLADEGA SAWMILL	AL	12/18/2017	250 Hp Emergency CI, Diesel-fired RICE	0				
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY GENERATOR DIESEL	0	100 H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY DIESEL FIRE PUMP	100	H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation		
MO-0089	OWENS CORNING INSULATION SYSTEMS, LLC	MO	5/12/2016	emergency engines	0		good operating practices		
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	44	H/YR	use of ULSD a clean burning fuel, and limited hours of operation		
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Emergency Diesel Fire Pump	100	H/YR	use of ULSD a clean burning fuel, and limited hours of operation		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	FL	9/16/2014	Emergency Diesel Engine	3300	hp	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with		
MS-0092	EMBERCLEAR GTL MS	MS	5/8/2014	firewater pumps, diesel	325	HP, EACH			
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Fire pump	0		Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H			
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Emergency Generator	200	H/YR	use of ULSD, a low sulfur clean fuel		
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	TWO (2) EMERGENCY GENERATORS	1341	HORSEPOWER, EACH	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION		
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	THREE (3) FIREWATER PUMP ENGINES	575	HORSEPOWER, EACH	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION		
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - Development Driller 1	2229	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur		
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - C.R. Luigs	2064	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		

TABLE E-16
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR TOTAL PARTICULATE MATTER

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Fire Pump Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		
CA-1192	AVENAL ENERGY PROJECT	CA	6/21/2011	EMERGENCY FIREWATER PUMP ENGINE	288	HP	USE ULTRA LOW SULFUR FUELNOT TO EXCEED 15 PPMVD FUEL SULFUR, OPERATIONAL LIMIT OF 50 HRS/YR		
NH-0018	BERLIN BIOPOWER	NH	7/26/2010	EU03 FIRE PUMP ENGINE	2.27	MMBTU/H			

TABLE E-17
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	% S fuel
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	% S fuel
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	% S fuel
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	% S fuel
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.0015	% S fuel
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.0015	% S fuel
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	150	hp		0.0015	% S fuel
*IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	IN	2/23/2018	Emergency Diesel Generators	250	hp		0.0015	% S fuel
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	Two 3300 kW emergency generators	0		Clean fuel	0.0015	% S fuel
*FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	Emergency Fire Pump Engine (422 hp)	0		Clean fuel	0.0015	% S fuel
*MA-0043	MIT CENTRAL UTILITY PLANT	MA	6/21/2017	Cold Start Engine	19.04	MMBTU/HR		0.0015	% S fuel
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	% S fuel
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	1.66	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	% S fuel
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	0		Ultra Low Sulfur Diesel/Fuel (15 ppm max)	0.0015	% S fuel
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	0		Ultra Low Sulfur Diesel/Fuel (15 ppm max)	0.0015	% S fuel
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Three 3300-kW ULSD emergency generators	0		Use of ULSD	0.0015	% S fuel
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	One 422-hp emergency fire pump engine	0		Use of ULSD	0.0015	% S fuel
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	EMERGENCY FIRE PUMP ENGINE	0		AMOUNT OF DIESEL BURNED SHALL NOT EXCEED 1,128 GALLONS PER 12 MONTH PERIOD	0.0015	% S fuel
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Limit in S in fuel	0.0015	% S fuel
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	TX	4/1/2015	Emergency Diesel Generator	1500	hp	Low sulfur fuel 15 ppmw	0.0015	% S fuel
*TX-0671	PROJECT JUMBO	TX	12/1/2014	Engines	0		Ultra low sulfur fuel engines burn will meet the sulfur requirement of 15 ppm in 40CFR80.510(b)	0.0015	% S fuel

TABLE E-17
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0703	LOW DENSITY POLYETHYLENE (LDPE) PLANT	TX	8/8/2014	Emergency Generators	0		Diesel-fired emergency generators meets 40 CFR 60 Subpart III requirements and diesel sulfur requirements of 40 CFR 80.510	0.0015	% S fuel
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Four 3100 kW black start emergency generators	2.32	MMBtu/hr (HHV) per engine	ULSD required	0.0015	% S fuel
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Emergency fire pump engine (300 HP)	29	MMBTU/H	Good combustion practice and ULSD	0.0015	% S fuel
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY GENERATOR 1	2250	KW	USE OF ULTRA-LOW DIESEL SULFUR FUEL, LIMITED HOURS OF OPERATION AND DESIGNED TO MEET NSPS SUBPART IIII LIMITS	0.0015	% S fuel
*MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	477	HP	USE OF ULTRA-LOW DIESEL SULFUR FUEL, LIMITED HOURS OF OPERATION AND DESIGNED TO MEET SUBPART IIII LIMITS	0.0015	% S fuel
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Emergency diesel fire pump	0		Use of Ultra low sulfur fuel oil	0.0015	% S fuel
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Emergency Engine/Generator	7.4	MMBTU/H		0.0015	% S fuel
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Fire Pump Engine	2.7	MMBTU/H		0.0015	% S fuel
TX-0706	NATURAL GAS FRACTIONATION	TX	1/23/2014	Emergency Engines	0		Sulfur emissions from engines will be minimized by using ultra-low diesel fuel with a maximum sulfur content of 15 ppm.	0.0015	% S fuel
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATOR SN-62	625	HP	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.0015	% S fuel
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Emergency generator	0		Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.	0.0015	% S fuel
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Fire pump	0		Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.	0.0015	% S fuel
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	EMERGENCY GENERATOR-ENGINE	0		The permittee shall only use diesel fuel that is classified as ULTRA-LOW SULFUR NON-HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum).	0.0015	% S fuel
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	371	BHP, EACH	ULTRA LOW SULFUR DISTILLATE AND USAGE LIMITS	0.0015	% S fuel
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	1006	HP EACH	ULTRA LOW SULFUR DISTILLATE AND USAGE LIMITS	0.0015	% S fuel
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY DIESEL GENERATOR	2012	HP	ULTRA LOW SULFUR DISTILLATE AND UASGE LIMITS	0.0015	% S fuel
WY-0071	SINCLAIR REFINERY	WY	10/15/2012	Emergency Air Compressor	400	hp	Ultra Low Sulfur Diesel	0.0015	% S fuel
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Diesel Emergency Generator (EP15)	839	hp	Ultra Low Sulfur Diesel	0.0015	% S fuel
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Diesel Fire Pump Engine (EP16)	327	hp	Ultra Low Sulfur Diesel	0.0015	% S fuel
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	TWO (2) EMERGENCY GENERATORS	1341	HORSEPOWER, EACH	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0.0015	% S fuel
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	THREE (3) FIREWATER PUMP ENGINES	575	HORSEPOWER, EACH	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0.0015	% S fuel

TABLE E-17
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	FIRE PUMP	500	HP	USE OF LOW SULFUR FUEL DIESEL, SULFUR CONTENT LESS THAN 0.0015 PERCENT. OPERATING HOURS LESS THAN 100 HOURS PER YEAR FOR MAINTENACE AND TESTING.	0.0015	% S fuel
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	757	HP	USE OF LOW SULFUR FUEL DIESEL, SULFUR CONTENT LESS THAN 0.0015 PERCENT. OPERATING HOURS LESS THAN 100 HOURS PER YEAR FOR MAINTENACE AND TESTING.	0.0015	% S fuel
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	2000 KW Emergency Equipment	0		See Pollutant Notes.	0.0015	% S fuel
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	9/23/2011	600 HP Emergency Equipment	0		See Pollutant Notes.	0.0015	% S fuel
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	Two emergency diesel firewater pump engines	250	HP		0.0015	% S fuel
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	FL	12/23/2010	250 Kw Emergency Generator	0			0.0015	% S fuel
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H		0.00151527	% S fuel
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	3.25	MMBTU/H		0.00152186	% S fuel
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Caterpillar C18DITA Diesel Engine Generator	900	BHP	use low sulfur fuel oil	0.05	% S fuel
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	182	BHP	use low sulfur fuel oil	0.05	% S fuel
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Fire Pump	0			0.003	LB/H
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP		0.003	LB/H
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	0.005	LB/HR
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Fire Pump Engine - 460 BHP	0			0.005	G/HP-H
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Emergency Generator	0			0.005	G/B-HP-H
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Fire Pump	0			0.005	G/B-HP-H
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Generator	0			0.006	LB/H
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0.03	LB/HR

TABLE E-17
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR SULFUR DIOXIDE (SO2)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	0.03	LB/HR
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	2250	KW		0.03	LB/H
IN-0185	MAG PELLET LLC	IN	4/24/2014	DIESEL FIRE PUMP	300	HP		0.29	LB/MMBTU
*AL-0318	TALLADEGA SAWMILL	AL	12/18/2017	250 Hp Emergency CI, Diesel-fired RICE	0				
LA-0305	LAKE CHARLES METHANOL FACILITY	LA	6/30/2016	Diesel Engines (Emergency)	4023	hp	Complying with 40 CFR 60 Subpart IIII		
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)			
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)			
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Generator	60	Gal/hr			
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Firewater Pump	16	Gal/hr			
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATORS	1500	KW	GOOD O		
SC-0113	PYRAMAX CERAMICS, LLC	SC	2/8/2012	EMERGENCY ENGINE 1 THRU 8	29	HP	LOW SULFUR DIESEL. MAXIMUM OF 100 HOURS PER YEAR RUNNING TIME FOR MAINTENANCE AND TESTING.		

TABLE E-18
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2 and CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0402	SUMPTER POWER PLANT	MI	11/17/2011	Diesel fuel-fired combustion engine (RICE)	732	HP	Good combustion practices	444.0	g/hp-hr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	526.2	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	526.39	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	526.39	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	B-HP	GOOD COMBUSTION PRACTICES	526.39	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	RAW WATER PUMP	500	HP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Emergency Generator	2015.7	HP		543.7	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Fire Pump Engine	251	HP		558.4	g/hp-hr
TX-0766	GOLDEN PASS LNG EXPORT TERMINAL	TX	9/11/2015	Emergency Engine Generators	750	hp	Equipment specifications & work practices - Good combustion practices and limited operational hours	619.9	g/hp-hr
*WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	WI	4/1/2019	P37 Diesel-Fired Emergency Fire Pump	0		Hours of Operation		
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Firewater Pump Engine	420	horsepower			
*IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Emergency Engine	1500	kW			
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and energy efficiency measures.		
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	6000	HP	Good combustion practices and energy efficiency measures.		
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUFPRICE--A 315 HP diesel fueled emergency engine	2.5	MMBTU/H	Good combustion practices and energy efficiency measures.		
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	good operating practices (proper maintenance and operation)		
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	good operating practices (proper maintenance and operation)		

TABLE E-18
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2 and CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	good operating practices (proper maintenance and operation)		
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and energy efficiency measures.		
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	6000	HP	Good combustion practices and energy efficiency measures.		
*MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUFPRICE--A 315 HP diesel fueled emergency engine	2.5	MMBTU/H	Good combustion practices and energy efficiency measures.		
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				
*IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2	MW	Energy efficient design.		
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	Energy efficient design		
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices.		
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices.		
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices.		
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices.		
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Good Combustion Practices		
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Good Combustion Practices		
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	use of S15 ULSD and high efficiency design and operation		
*VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.		
*AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Good Combustion Practices		
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	650	horsepower	Compliance with NSPS Subpart IIII		
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII		

TABLE E-18
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2 and CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0824	JACKSON COUNTY GENERATING FACILITY	TX	6/30/2017	Emergency Diesel-Fired Equipment	160	HP	Good operating and maintenance practices, efficient design, and low annual capacity		
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	500	H/YR	Good combustion and design practices.		
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	500	H/YR	Good combustion and design practices.		
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUFIREPUMP in FGRICE (Diesel fire pump engine)	500	H/YR	Good combustion and design practices.		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	firewater pump engines (8 units)	460	hp	good combustion practices		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	emergency generator engines (6 units)	3353	hp	good combustion practices		
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Fire Water Diesel Pump No. 3 Engine	600	hp	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Fire Water Diesel Pump No. 4 Engine	600	hp	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	Standby Generator No. 9 Engine	400	hp	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	1.66	MMBTU/H	Good combustion practices		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Emergency Generator Engines (4 units)	0		complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Firewater pump Engines (4 units)	896	hp (each)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		
*LA-0306	TOPCHEM POLLOCK, LLC	LA	12/20/2016	Genenerator Engine DEG-16-1 (EQT035)	460	horsepower	Meet NSPS Subpart IIII Limitations and Good Combustion Practices		
*LA-0306	TOPCHEM POLLOCK, LLC	LA	12/20/2016	Pump Engines DFP-16-1 (EQT036)	225	horsepower	Good Combustion Practices		
*LA-0306	TOPCHEM POLLOCK, LLC	LA	12/20/2016	Pump Engine DFP-16-2 (EQT037)	225	horsepower	Good Combustion Practices		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	500	H/YR	Good combustion practices.		
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Generator 1	2584	HP	Good combustion practices		
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	282	HP	Good combustion practices		
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	500	H/YR	Good combustion and design practices.		
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Dieself fire pump engine (EUFIREPUMP in FGRICE)	500	H/YR	Good combustion and design practices.		

TABLE E-18
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2 and CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel Firewater pump engines (6 units)	425	hp			
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel emergency generator engine - EGEN	350	hp			
LA-0305	LAKE CHARLES METHANOL FACILITY	LA	6/30/2016	Diesel Engines (Emergency)	4023	hp	Complying with 40 CFR 60 Subpart IIII		
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	0		Good Combustion Practices/Maintenance		
*VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	0		Good Combustion Practices/Maintenance		
TX-0799	BEAUMONT TERMINAL	TX	6/8/2016	Fire pump engines	0		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.		
TX-0799	BEAUMONT TERMINAL	TX	6/8/2016	EMERGENCY ENGINES	0		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.		
*KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART	KS	3/31/2016	Compression ignition RICE emergency fire pump	197	HP			
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Good combustion practice and efficient engine design.		
LA-0292	HOLBROOK COMPRESSOR STATION	LA	1/22/2016	Emergency Generators No. 1 & No. 2	1341	HP			
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine	15	gal/hr			
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	0				
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Emergency Generator	0				
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Lowest-emitting available fuel		
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	KS	7/14/2015	Emergency diesel engine	750	KW			
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)			
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)			
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Emergency Camp Generators	2695	hp			
OK-0164	MIDWEST CITY AIR DEPOT	OK	1/8/2015	Diesel-Fueled Fire Pump Engines	300	HP	1. Good Combustion Practices. 2. Efficient Design.		
TX-0753	GUADALUPE GENERATING STATION	TX	12/2/2014	Fire Water Pump Engine	1.92	MMBtu/hr (HHV)			
TX-0758	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	Firewater Pump Engine	0				

TABLE E-18
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2 and CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WY-0076	ROCK SPRINGS FERTILIZER COMPLEX	WY	7/1/2014	Fire Water Pump Engine	200	HP	limited to 500 hours of operation per year		
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or		
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or		
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or		
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 1	5364	HP	Proper design and operation; energy efficiency measures		
*LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 2	5364	HP	Proper design and operation; energy efficiency measures		
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 1	751	HP	Proper design and operation; use of ultra-low sulfur diesel		
*LA-0315	G2G PLANT	LA	5/23/2014	Fire Pump Diesel Engine 2	751	HP	Proper design and operation; use of ultra-low sulfur diesel		
TX-0757	INDECK WHARTON ENERGY CENTER	TX	5/12/2014	Firewater Pump Engine	175	hp			
IN-0185	MAG PELLET LLC	IN	4/24/2014	DIESEL FIRE PUMP	300	HP			
ID-0021	MAGNIDA	ID	4/21/2014	EMERGENCY GENERATOR ENGINE	2000	kW			
ID-0021	MAGNIDA	ID	4/21/2014	FIRE WATER PUMP ENGINE	500	brake horsepower			
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE	PR	4/10/2014	Emergency Diesel Fire Pump	0				
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE	PR	4/10/2014	Emergency Diesel Generator	0				
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Emergency Engine/Generator	7.4	MMBTU/H			
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Fire Pump Engine	2.7	MMBTU/H			
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Generator	60	Gal/hr			
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Emergency Firewater Pump	16	Gal/hr			
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	1000	kW	Good combustion practices.		
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	2000 KW Diesel Fired Emergency Generator Engine	20.4	MMBTU/hr	Good combustion practices		

TABLE E-18
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2 and CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	380 HP Diesel Fired Pump Engine	2.3	MMBTU/hr	Good combustion practices		
AR-0140	BIG RIVER STEEL LLC	AR	9/18/2013	EMERGENCY GENERATOR SN-62	625	HP	GOOD COMBUSTION PRACTICES		
OK-0156	NORTHSTAR AGRI IND ENID	OK	7/31/2013	Fire Pump Engine	550	hp	Good Combustion		
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Emergency Generators	180	GAL/H	good combustion practices		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Emergency Generators	180	GAL/H	good combustion practices		
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	1341	HP	A TIER 3 CERTIFIED ENGINE OPERATED < 100 HR/YR.		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP			
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	2250	KW			
CO-0067	LANCASTER PLANT	CO	6/4/2013	Emergency Generator	19950	gal per year	NSPS IIII compliant.		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	3.25	MMBTU/H			
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H			
LA-0272	AMMONIA PRODUCTION FACILITY	LA	3/27/2013	EMERGENCY DIESEL GENERATOR (2205-B)	1200	HP	ENERGY EFFICIENCY MEASURES		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	371	BHP, EACH	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	1006	HP EACH	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	EMERGENCY DIESEL GENERATOR	2012	HP	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN POST COMBUSTION CARBON CAPTURE		
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Emergency Generator	142	GAL/H	good combustion practices		
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Emergency Generator	142	GAL/H	good combustion practices		
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Fire Pump	14	GAL/H	good combustion practices		
IA-0105	IOWA FERTILIZER COMPANY	IA	10/26/2012	Fire Pump	14	GAL/H	good combustion practices		
VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	VA	8/27/2012	FIRE WATER PUMP	1.86	MMBTU/H	Fuel-efficient design		

TABLE E-18
DIESEL FUEL FIRED RECRIPROCATING INTERNAL COMBUSTION ENGINES (VARIOUS PROCESS TYPES), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR GREENHOUSE GASES (CO2 and CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AK-0076	POINT THOMSON PRODUCTION FACILITY	AK	8/20/2012	Combustion of Diesel by ICEs	1750	kW	Good Combustion Practices and 40 CFR 60 Subpart IIII requirements		
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	TWO (2) EMERGENCY GENERATORS	1341	HORSEPOWER, EACH	USE OF GOOD ENGINEERING DESIGN AND EFFICIENT ENGINES MEETING APPLICABLE NSPS AND MACT STANDARDS		
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	THREE (3) FIREWATER PUMP ENGINES	575	HORSEPOWER, EACH	USE OF GOOD ENGINEERING DESIGN AND EFFICIENT ENGINES MEETING APPLICABLE NSPS AND MACT STANDARDS		
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - Development Driller 1	2229	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur		
FL-0338	SAKE PROSPECT DRILLING PROJECT	FL	5/30/2012	Emergency Generator Diesel Engine - C.R. Luigs	2064	hp	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur		
TX-0612	THOMAS C. FERGUSON POWER PLANT	TX	11/10/2011	EMGEN1-STK - DIESEL FIRED EMERGENCY GENERATOR	93.8				
TX-0612	THOMAS C. FERGUSON POWER PLANT	TX	11/10/2011	EMGEN1-STK - DIESEL FIRED EMERGENCY GENERATOR	93.8		To fire diesel fuel containing no more than 0.5 percent sulfur by weight.		
TX-0612	THOMAS C. FERGUSON POWER PLANT	TX	11/10/2011	FWP1-STK DIESEL FIRED FIRE WATER PUMP	617	HP	Best Work practice		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	FL	10/27/2011	Emergency Fire Pump Engine	0		Use of good combustion practices, based on the current manufacturer's specifications for this engine		
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	EMERGENCY DIESEL GENERATOR	1250	HP	PROPER OPERATION AND GOOD COMBUSTION PRACTICES		
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	EMERGENCY FIRE PUMP	350	HP	PROPER OPERATION AND GOOD COMBUSTION PRACTICES		

TABLE E-19
COOLING TOWERS (Varioius Process Types), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR PARTICULATE MATTER (PM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUCOOLINGTWR: Cooling Tower	0		High efficiency drift/mist eliminators (filterable PM)	0.0005	%
*MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCOOLTOWER (North Plant): Cooling Tower	170000	GAL/M	High efficiency drift/mist eliminators (filterable PM)	0.0005	%
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Cooling Tower 2 (P-35)	26000	gal/m	Drift Eliminator (PM10)	0.0005	%
*LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Cooling Tower 2 (P-35)	26000	gal/m	Drift Eliminator (PM2.5)	0.0005	%
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EIGHTEEN CELL COOLING TOWER (EU-010)	0		HIGH EFFICIENCY DRIFT ELIMINATORS (PM2.5)	0.0005	%
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EIGHTEEN CELL COOLING TOWER (EU-010)	0		HIGH EFFICIENCY DRIFT ELIMINATORS (PM10)	0.0005	%
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EIGHTEEN CELL COOLING TOWER (EU-010)	0		HIGH EFFICIENCY DRIFT ELIMINATORS (total PM)	0.0005	%
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Cooling Towers	0		drift eliminators (PM10)	0.0005	%
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Cooling Towers	0		drift eliminators (PM2.5)	0.0005	%
*NE-0059	AGP SOY	NE	3/25/2015	Cooling Tower	360000	gal/hr	drift loss design specification and TDS concentration limit (total PM)	0.0005	%
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	cooling tower	0		drift eliminators (PM2.5)	0.0005	%
MI-0417	GERDAU MACSTEEL, INC.	MI	10/27/2014	EUCASTERCOOLTWR (Caster cooling tower)	1630	GAL/MIN	DRIFT ELIMINATOR (PM2.5)	0.0005	%
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Cooling Tower	0		drift eliminators; TDS of water not to exceed 2000 mg/l	0.0005	%
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Cooling Tower	0		drift eliminators; TDS of water not to exceed 2000 mg/l	0.0005	%
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Cooling Tower	0		drift eliminators; TDS of water not to exceed 2000 mg/l	0.0005	%
OK-0162	ENID NITROGEN PLANT	OK	5/29/2014	Cooling Towers	0		Drift Eliminators (PM10)	0.0005	%
OK-0162	ENID NITROGEN PLANT	OK	5/29/2014	Cooling Towers	0		Drift Eliminators (PM2.5)	0.0005	%
TX-0725	DIRECT REDUCED IRON AND HOT BRIQUETTING FACILITY	TX	3/18/2014	Cooling Tower	2205000		A cooling tower with a drift loss of 0.0005%. (PM10)	0.0005	%

TABLE E-19
COOLING TOWERS (Varioius Process Types), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR PARTICULATE MATTER (PM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0725	DIRECT REDUCED IRON AND HOT BRIQUETTING FACILITY	TX	3/18/2014	Cooling Tower	2205000		A cooling tower with a drift loss of 0.0005%. (PM2.5)	0.0005	%
TX-0725	DIRECT REDUCED IRON AND HOT BRIQUETTING FACILITY	TX	3/18/2014	Cooling Tower	2205000		A cooling tower with a drift loss of 0.0005%. (total PM)	0.0005	%
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCOOLTWR (Cooling Tower--Wet Mechanical Drift)	0		Mist/Drift Eliminators (filterable PM)	0.0006	%
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCOOLTWR (Cooling Tower--Wet Mechanical Drift)	0		Mist/Drift Eliminators (PM10)	0.0006	%
MI-0427	FILER CITY STATION	MI	11/17/2017		0		Mist/Drift Eliminators (PM2.5)	0.0006	%
*FL-0368	NUCOR STEEL FLORIDA FACILITY	FL	2/14/2019	Two Cooling Towers	19650	gal/min	DRIFT ELIMINATORS (Total PM)	0.001	%
*IL-0126	NUCOR STEEL KANKAKEE, INC.	IL	11/1/2018	Cooling Towers	4500	gallons/minute	Drift eliminators (total PM)	0.001	%
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	cooling towers (I-CT-621, II-CT-621)	66000	gpm (each)	Drift eliminators (PM10)	0.001	%
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	cooling towers (I-CT-621, II-CT-621)	66000	gpm (each)	drift eliminators (PM2.5)	0.001	%
OK-0173	CMC STEEL OKLAHOMA	OK	1/19/2016	Cooling Towers	0		Drift eliminators (PM10).	0.001	%
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	cooling tower	0		mist eliminators (PM2.5)	0.001	%
TX-0703	LOW DENSITY POLYETHYLENE (LDPE) PLANT	TX	8/8/2014	Cooling Tower	0		Cooling Tower will have drift eliminators (PM2.5)	0.001	%
*TX-0657	BEAUMONT GAS TO GASOLINE PLANT	TX	5/16/2014	cooling tower	99000000	gallons/yr	Drift eliminators (limit 0.001 % drift)and monitoring of TDS or conductivity Emission Limit for PM is 82.57 tpy Emission Limit for PM10 is 1.28 tpy Emission Limit for PM2.5 is 0.03 tpy	0.001	%
MS-0092	EMBERCLEAR GTL MS	MS	5/8/2014	Cooling tower, Induced draft	1420	GAL/MIN	high efficiency drift eliminators (PM10)	0.001	%
MS-0092	EMBERCLEAR GTL MS	MS	5/8/2014	Cooling tower, Induced draft	1420	GAL/MIN	high efficiency drift eliminators (PM2.5)	0.001	%
MS-0092	EMBERCLEAR GTL MS	MS	5/8/2014	Cooling tower, Induced draft	1420	GAL/MIN	high efficiency drift eliminators (total PM)	0.001	%
AK-0083	KENAI NITROGEN OPERATIONS	AK	1/6/2015	2 Cell Cross-Flow Cooling Tower	15000	gallons per minute	High Efficiency Drift Eliminators (PM2.5)	0.002	%

TABLE E-19
COOLING TOWERS (Varioius Process Types), PERMIT DATES FROM 01/01/2008 THROUGH 10/29/2019
LISTINGS FOR PARTICULATE MATTER (PM)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGH PUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	TX	9/9/2019	Cooling Tower	0		drift eliminators	0.005	%
*TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	TX	9/9/2019	Cooling Tower	0		DRIFT ELIMINATORS (PM10)	0.005	%
*TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	TX	9/9/2019	Cooling Tower	0		DRIFT ELIMINATORS (PM2.5)	0.005	%
*TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	TX	9/9/2019	COOLING TOWER	0		DRIFT ELIMINATORS (Total PM)		
*TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	TX	9/9/2019	COOLING TOWER	0		DRIFT ELIMINATORS (PM10)		
*TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	TX	9/9/2019	COOLING TOWER	0		DRIFT ELIMINATORS (PM2.5)		
*TX-0863	POLYETHYLENE 7 FACILITY	TX	9/3/2019	COOLING TOWER	0		DRIFT ELIMINATOR (PM10)		
*TX-0863	POLYETHYLENE 7 FACILITY	TX	9/3/2019	COOLING TOWER	0		DRIFT ELIMINATOR (PM2.5)		
OH-0378	PTTGCA PETROCHEMICAL	OH	12/21/2018	Cooling Tower (P011)	13.88	MMGAL/H	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not		
OH-0378	PTTGCA PETROCHEMICAL	OH	12/21/2018	Cooling Tower (P011)	13.88	MMGAL/H	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not		
OH-0378	PTTGCA PETROCHEMICAL	OH	12/21/2018	Cooling Tower (P011)	13.88	MMGAL/H	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not		
MI-0437	KNAUF INSULATION, INC.--ALBION FACILITY	MI	10/18/2018	EU-COOLTOWER (Cooling tower)	1500	gal/min	Drift eliminators		
MI-0437	KNAUF INSULATION, INC.--ALBION FACILITY	MI	10/18/2018	EU-COOLTOWER (Cooling tower)	1500	gal/min	Drift eliminators		
MI-0437	KNAUF INSULATION, INC.--ALBION FACILITY	MI	10/18/2018	EU-COOLTOWER (Cooling tower)	1500	gal/min	Drift eliminators		

Appendix F

Greenhouse Gas BACT Supplemental Information

Table F-1 Potential CO_2 Emissions from Combined Cycle Units

Emission Factor[1] (lb/MMBtu)	Total Potential Heat Input[2] (MMBtu/hr)	Operating Duration (hr/yr)	Total Potential Emissions[3] (tpy CO_2)
117	9,534	8,760	**4,885,000**[4]

1. From Table C-1 of Subpart C of 40 CFR 98 for Natural Gas
2. Total Heat Input Capacity includes:
   Unit 8 Combustion Turbine 3,939 MMBtu/hr
   Unit 9 Combustion Turbine 3,939 MMBtu/hr
   Unit 8 Duct Burner 828 MMBtu/hr
   Unit 9 Duct Burner 828 MMBtu/hr
3. Emissions (tpy) = EF (lb/MMBtu) * Total Heat Input Capacity (MMBtu/hr) * Operating Duration (hr/yr)
4. See Appendix D, Table D-5 for emissions for one combined cycle unit.

Table F-2 Assumptions Used in CCUS Cost Estimation

Parameters	Value	Unit
Pipeline Length[1]	12	mi
Pipeline Diameter[2]	12	in
Number of Primary and Backup Injection Wells[3]	8	
Number of Pressure Monitoring Wells[3]	4	
Number of Ground Water Monitoring Wells[3]	5	
Uncontrolled Annual CO_2 Emissions[4]	4,885,000	tpy
Control Efficiency[5]	90	%
Annual Captured CO_2 Emissions	4,396,500	tpy
	12,045	tpd

1. Distance from the facility to the nearest potential CO_2 sequestration facility (Citronelle Dome).
2. Determined using *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies,* National Energy Technology laboratory, U.S. DOE, DOE/NETL-2019/2044 (August 2019) and FE/NETL CO_2 Transport Cost Model (Excel spreadsheet).
3. Estimates were based on previous site characterization completed through DOE's Southeastern Regional Carbon Sequestration Program (RCSP).
4. Potential CO_2 emissions calculated in Table F-1.
5. 90% CCS Control Efficiency from *Cost and Performance Baseline for Fossil Energy Plants Volume 1*, National Energy Technology laboratory, NETL-PUB-22638 (September 2019). 90% Capture is a common standard to facilitate comparison among various publicly available cost studies.

Table F-3 Total Costs for Carbon Capture

Estimated Annual Captured CO_2[1]	4,396,500	tpy
Cost of CO_2 Capture from Recent NGCC Post Combustion Capture Studies[2]		
Global Costs of Carbon Capture and Storage: 2017 Update, Global CCS Institute (June 2017)[3]	55.28	\$/ton CO_2 captured
Cost and Performance Baseline for Fossil Energy Plants Volume 1, National Energy Technology laboratory, NETL-PUB-22638 (September 2019)[4]	65.25	\$/ton CO_2 captured
Cost and Performance Characteristics of New Generating Technologies: Annual Energy Outlook 2018, US Energy Information Administration, (February 2018)[5]	86.05	\$/ton CO_2 captured
Levelized Annual Total Costs for CO_2 Capture[6]	\$302,747,059	annual additional cost to ratepayers for CO_2 capture

1. Estimated captured CO_2 from Table F-2
2. \$ / ton CO_2 captured for each study was calculated using the increase in levelized cost of electricity (LCOE) in \$/MWh between the non-capture and capture cost estimates divided by the CO2 capture rate (tons/MWh) of the capture case on a constant MWh basis. The LCOE consists of capital, O&M, and fuel components. Total overnight capital costs (MM\$) were converted to levelized annual capital costs (\$/MWh) using the annual MWh output and a fixed charge rate (FCR) that accounts for the weighted average cost of capital (WACC) and depreciation. Annual O&M costs were escalated and levelized using an assumed escalation rate and the WACC. Annual fuel costs were levelized using a projected fuel price forecast and the WACC.
3. The LCOE and \$/ton CO_2 captured published in this study were adjusted from 85% capacity factor to 100% to align with permitting application. The study FCR was based on funding with 40% debt and 60% equity and an after tax WACC of 8.74%
4. The LCOE and \$/ton CO_2 captured published in this study were adjusted from 85% capacity factor to 100% to align with the permit application. The study FCR was based on funding with 55% debt and 45% equity and an after tax WACC of 6.54%
5. The LCOE and \$/ton CO_2 captured published in this study were adjusted from 85% capacity factor to 100% to align with the permit application. The study did not provide financing assumptions so a typical investor-owned-utility assumption of 60% debt, 40% equity, and an after tax WACC of 7.7% was applied. *Lazard's Levelized Cost of Energy Analysis – Version 13.0*, Lazard, (November, 2019).
6. Estimated Annual Total Costs for CO_2 Capture = Estimated Annual Captured CO_2 (tpy) * Average \$/ton CO_2 captured from 3 studies

Table F-4 Capital and O&M Costs for CO_2 Transportation and Storage

Transportation and Storage Capital Costs

Pipeline Costs[1]	Formula for Estimate[2]	Units	June 2011 Dollars	June 2020 Dollars
Pipeline Materials	70,350+2.01*L*(330.5*D2+686.7*D+26,960)	\$, D(in), L(mi)	\$2,068,926	
Pipeline Labor	371,850+2.01*L*(343.2*D2+2,074*D+170,013)	\$, D(in), L(mi)	\$6,268,854	
Pipeline Right of Way	51,200+1.28*L*(577*D+29,788)	\$, D(in), L(mi)	\$616,527	
Pipeline Miscellaneous	147,250+1.55*L*(8,417*D+7,234)	\$, D(in), L(mi)	\$2,177,378	
Surge Tank			\$1,244,744	
Pipeline Control System			\$111,907	
Total Pipeline Capital[4]			\$12,488,336	\$15,596,220

Storage Costs[3]	Number	Unit Cost, \$MM	June 2019 Dollars	June 2020 Dollars
Primary Injection Wells	5	\$5.0	\$25,000,000	
Backup Injection Wells	3	\$5.0	\$15,000,000	

Pressure Monitoring Wells	4	$4.0	$16,000,000	
Groundwater Monitoring Wells	5 Deep / 20 shallow	$0.20 / $0.025	$1,500,000	
Distribution Lines & Pumps	1 / 2	$10.0 / $1.0	$12,000,000	
Seismic and Microseismic Monitoring	Various	Various	$9,800,000	
Total Storage Capital[4]			$79,300,000	$81,282,500
	Total Capital + 15% Contingency			$111,410,530
Transportation and Storage O&M Costs				
Levelized Annual Transportation O&M[1,5]				$262,100
Levelized Annual Storage O&M[3,5]				$6,057,200

1. Transportation Capital and O&M values in 2011 dollars were developed with the FE/NETL CO_2 Transport Cost Model as detailed in: *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies,* National Energy Technology laboratory, U.S. DOE, DOE/NETL-2019/2044 (August 2019)
2. Formulas for estimate do not give the same result as the CO_2 Transport Cost Model but are within 1%. They are for illustrative purposes.
3. Storage Capital and O&M estimates in 2019 dollars were based on previous site characterization completed through DOE's Southeastern Regional Carbon Sequestration Program (RCSP). The site is fully characterized and has been previously permitted with CO_2 injection and subsurface monitoring that was recently closed out from a pilot carbon capture unit at the site that captured CO_2 at a rate of 500 tpd.
4. "Total Pipeline Capital" in 2011 Dollars and "Total Storage Capital" in 2019 Dollars are changed to 2020 Dollars by escalating the capital expenses by 2.5% per year.
5. Transportation and Storage O&M costs were levelized by escalating costs in 2011 and 2019 dollars, respectively, by 2.5% annually throughout the relevant operating period to determine the NPV of each using a 7.7% discount factor. The levelized cost is the constant annual payment needed to equal the NPV assuming a 7.7% discount factor throughout the operating period. The operating period for transportation is 40 yrs while the operating period for storage includes 40 yrs of operation and 20 yrs of post-injection site monitoring to align with the CO_2 storage permitting (Class VI Underground Injection Control Permit).

Table F-5 Overall Cost of CCS

Levelized Annual Total Costs for CO_2 Capture[1]		$302,747,059
Total Capital Investment for CO_2 Transportation and Storage (TCI)[2]	$111,410,530	
Fixed Charge Rate (FCR)[3] (7.7% ATWACC, 2% property tax, AFUDC, 3 year construction period, 40 year operating period)	0.1132	
Amortized Annual Transportation and Storage Capital Costs (TCI*FCR)		$12,611,672
Levelized Annual Transportation O&M Costs[4]		$262,100
Levelized Annual CO_2 Storage O&M Costs[4]		$6,057,200
Total Annual CCS Costs		**$321,678,031**

1. From Table F-3
2. "Total Capital + 15% Contingency" from Table F-4
3. Grant, Ireson, and Leavenworth, *Principles of Engineering Economy, Seventh Edition*, Hoboken, NJ: John Wiley & Sons, 1982
4. From Table F-4

Appendix G

Air Dispersion Modeling Files

Appendix H

GEP Documentation

Barry Units 1-2 Common Stack

Alabama Power Company
600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291
Telephone 205 250-1000

Alabama Power
the southern electric system

December 11, 1985

Mr. Richard E. Grusnick, Chief
Air Division
Alabama Department of
Environmental Management
1751 Federal Drive
Montgomery, AL 36130

Dear Mr. Grusnick:

Reference is made to your letter of October 22, 1985 and our meeting of November 18, 1985 concerning the Stack Height Regulations promulgated by the Environmental Protection Agency on July 8, 1985. Attached are the following documents and data:

1. Determination of Good Engineering Practice stack heights for stacks greater than 65 meters APC 200 forms for Barry, Gadsden and Gorgas Steam Electric-Generating Plants.

2. Exceptions from restrictions on credit for merged stacks with attachments.

3. Air quality modeling analysis with attachments.

4. Emission inventory for Barry Steam Plant.

5. 1983 on-site meteorological data on computer tape for all Alabama Power Company coal-fired plants.

The stacks for Units 4 and 5 at the Barry Steam Plant and the stack for Units 8-10 at the Gorgas Steam Plant are grandfathered under the regulations. The stacks for Units 4 and 5 at the Barry Steam Plant were completed in May, 1969 and June, 1970, respectively. The stack for Units 8-10 at the Gorgas Steam Plant began construction in February, 1970.

It should be noted that the Gadsden and Gorgas Steam Plants will not require any additional modeling to prove compliance with the regulations. The stacks at these plants, as indicated on the APC 200 forms, are either grandfathered or less than Good Engineering Practice stack height.

Mr. Richard E. Grusnick
Page two
December 11, 1985

The APC 200 forms and the emission inventory for the remaining affected plants will be submitted within two weeks. This information has been delayed due to a recheck of construction drawings by our surveyors.

I would appreciate a meeting to discuss this information as soon as possible. If you have any questions, please call me.

Sincerely,

W. L. Bowers, Manager
Environmental Compliance

WDH:dy

Attachment

DETERMINATION OF GOOD ENGINEERING PRACTICE STACK HEIGHT
FOR STACKS GREATER THAN 65 METERS

1. Company Alabama Power Company

2. Address P. O. Box 2641 Birmingham, AL 35291

3. Permit Unit/Source Description Barry Steam Plant Units 1-3

   (a) Actual stack height above grade 600 feet

   (b) List the air emission sources which utilize this stack. Describe the air pollution control system. Attach diagrams or further explanation as needed. Barry Steam Plant Boilers 1, 2, and 3 with electrostatic precipitators.

4. Attach a top-view schematic drawing of the plant (drawn-to-scale) including geographical orientation. Label all buildings and stacks. Include height, width, and length of all buildings.

5. (a) GEP stack height 505 feet

   (b) Date construction started on stack June 1974

   (c) In the space provided below or in attachments show the GEP calculations and indicate the building used.

   The boiler house was used to determine the GEP height. See attached drawing.

6. Highest terrain elevation within 1/2 mile:

   (a) Height 40 feet

   (b) Distance and direction from stack 0.5 Miles West (Taken from U. S. Geological Map Citronelle 1:62500 Quad)

W. L. Bowers
Name of Company Official

Signature

12/12/85
Date

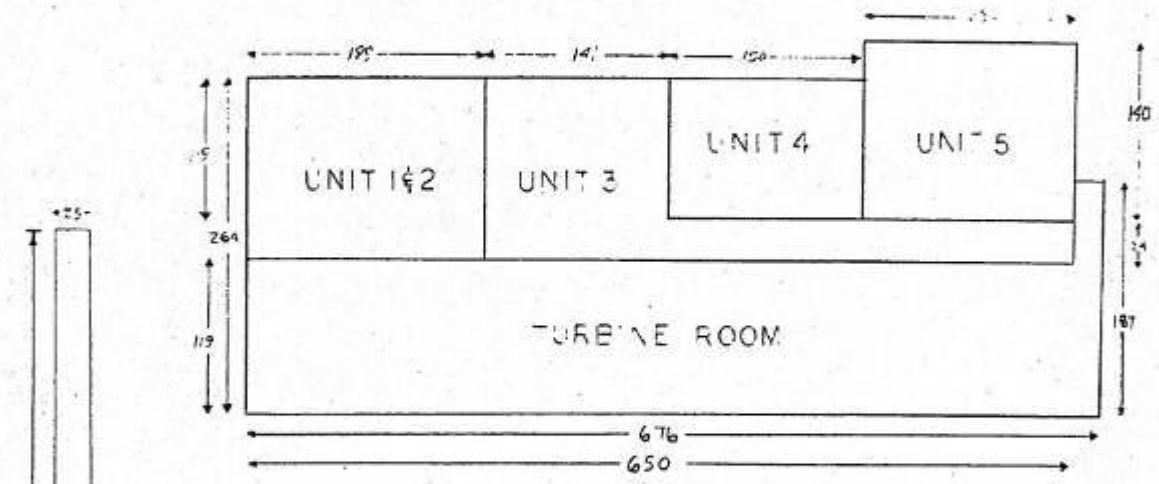
Design Calculations Alabama Power

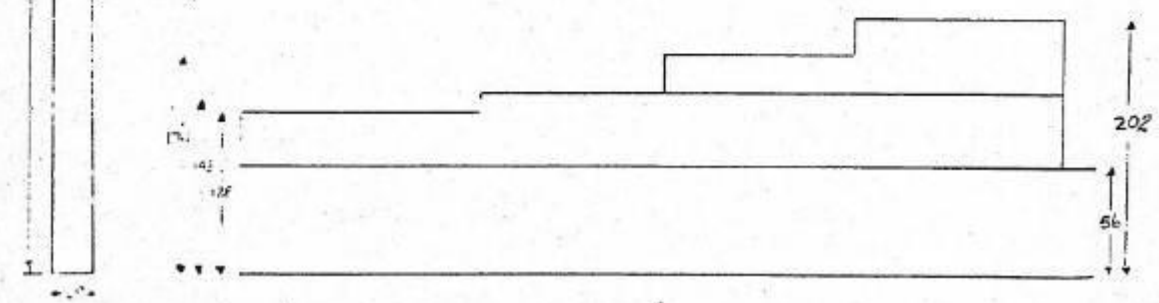
Project BARRY UNITS 1,2,3	Prepared By	Date
Subject/Title GEP STACK HEIGHT	Reviewed By	Date
SCALE 1 INCH = 120′	Calculation Number	Sheet of

USING BOILER HOUSE FOR UNIT 5
GEP = 2.5H
2.5X 202=505′

N

OVERHEAD VIEW





SIDE VIEW

Barry Unit 4 and Unit 5 Stacks

Alabama Power Company
600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291
Telephone 205 250-1000

Alabama Power
the southern electric system

December 11, 1985

Mr. Richard E. Grusnick, Chief
Air Division
Alabama Department of
Environmental Management
1751 Federal Drive
Montgomery, AL 36130

Dear Mr. Grusnick:

Reference is made to your letter of October 22, 1985 and our meeting of November 18, 1985 concerning the Stack Height Regulations promulgated by the Environmental Protection Agency on July 8, 1985. Attached are the following documents and data:

1. Determination of Good Engineering Practice stack heights for stacks greater than 65 meters APC 200 forms for Barry, Gadsden and Gorgas Steam Electric-Generating Plants.

2. Exceptions from restrictions on credit for merged stacks with attachments.

3. Air quality modeling analysis with attachments.

4. Emission inventory for Barry Steam Plant.

5. 1983 on-site meteorological data on computer tape for all Alabama Power Company coal-fired plants.

The stacks for Units 4 and 5 at the Barry Steam Plant and the stack for Units 8-10 at the Gorgas Steam Plant are grandfathered under the regulations. The stacks for Units 4 and 5 at the Barry Steam Plant were completed in May, 1969 and June, 1970, respectively. The stack for Units 8-10 at the Gorgas Steam Plant began construction in February, 1970.

It should be noted that the Gadsden and Gorgas Steam Plants will not require any additional modeling to prove compliance with the regulations. The stacks at these plants, as indicated on the APC 200 forms, are either grandfathered or less than Good Engineering Practice stack height.

Mr. Richard E. Grusnick
Page two
December 11, 1985

The APC 200 forms and the emission inventory for the remaining affected plants will be submitted within two weeks. This information has been delayed due to a recheck of construction drawings by our surveyors.

I would appreciate a meeting to discuss this information as soon as possible. If you have any questions, please call me.

Sincerely,

W. L. Bowers, Manager
Environmental Compliance

WDH:dy

Attachment

DETERMINATION OF GOOD ENGINEERING PRACTICE STACK HEIGHT
FOR STACKS GREATER THAN 65 METERS

1. Company ALABAMA POWER COMPANY

2. Address P. O. Box 2641, Birmingham, AL 35291

3. Permit Unit/Source Description Barry Steam Plant Unit 4

   (a) Actual stack height above grade 600 feet

   (b) List the air emission sources which utilize this stack. Describe the air pollution control system. Attach diagrams or further explanation as needed. Barry Steam Plant Boiler 4 with electrostatic precipitators.

4. Attach a top-view schematic drawing of the plant (drawn-to-scale) including geographical orientation. Label all buildings and stacks. Include height, width, and length of all buildings.

5. (a) GEP stack height Grandfathered

   (b) Date construction started on stack

   (c) In the space provided below or in attachments show the GEP calculations and indicate the building used.

   See attached information on grandfathering.

6. Highest terrain elevation within 1/2 mile:

   (a) Height 40 feet

   (b) Distance and direction from stack 0.5 miles west (taken from U. S. Geological Map Citronelle 1:62500 Quad)

W. L. Bowers
Name of Company Official

Signature

12/12/85
Date

ADC 300

DETERMINATION OF GOOD ENGINEERING PRACTICE STACK HEIGHT
FOR STACKS GREATER THAN 65 METERS

1. Company ALABAMA POWER COMPANY

2. Address P. O. Box 2641, Birmingham, AL 35291

3. Permit Unit/Source Description Barry Steam Plant Unit 5

   (a) Actual stack height above grade 600 feet

   (b) List the air emission sources which utilize this stack. Describe the air pollution control system. Attach diagrams or further explanation as needed. Barry Steam Plant Boiler 5 with electrostatic precipitators.

4. Attach a top-view schematic drawing of the plant (drawn-to-scale) including geographical orientation. Label all buildings and stacks. Include height, width, and length of all buildings.

5. (a) GEP stack height grandfathered

   (b) Date construction started on stack _____

   (c) In the space provided below or in attachments show the GEP calculations and indicate the building used.

   See attached information on grandfathering.

6. Highest terrain elevation within 1/2 mile:

   (a) Height 40 feet

   (b) Distance and direction from stack 0.5 Miles West (Taken from U. S. Geological Map Citronelle 1:62500 Quad)

W. L. Bowers
Name of Company Official

Signature

12/12/85
Date

Appendix I

Land Use Analysis

Land Use Analysis

Although the use of Mobile Regional Airport data for facilities in Mobile County was stipulated in ADEM's Modeling Guidelines, the meteorological data must be deemed representative of the Plant Barry site. The AERMOD Implementation Guide (AIG) (EPA, 2018) specifies that the determination of the representativeness of meteorological data for a particular application depends on a comparison of the surface characteristics (z_o, r, and B_o) between the meteorological monitoring site and the project site, coupled with a determination of the importance of any differences relative to predicted concentrations. Therefore, a comparison of the surface characteristics of the Plant Barry site and of those of Mobile Regional Airport was conducted. Surface characteristics for Mobile Regional Airport were provided by ADEM. Surface characteristics for the Plant Barry site were determined by the following procedure.

The AIG provides the following recommendations for determining the site characteristics:

1. The determination of the surface roughness length should be based on an inverse distance weighted geometric mean for a default upwind distance of 1 kilometer relative to the measurement site. Surface roughness length may be varied by sector to account for variations in land cover near the measurement site; however, the sector widths should be no smaller than 30 degrees. As discussed further below, 12 sectors were used in this application.
2. The determination of the Bowen ratio should be based on a simple unweighted geometric mean (i.e., no direction or distance dependency) for a representative domain, with a default domain defined by a 10 km by 10 km region centered on the measurement site.
3. The determination of the albedo should be based on a simple unweighted arithmetic mean (i.e., no direction or distance dependency) for the same representative domain as defined for Bowen ratio, with a default domain defined by a 10 km by 10km region centered on the measurement site.

The AIG recommends that the surface characteristics be determined based on digitized land cover data. EPA has developed a tool called AERSURFACE that was used to determine the site characteristics based on digitized land cover data in accordance with the recommendations from the AIG discussed above. AERSURFACE incorporates look-up tables of representative surface characteristic values by land cover category and seasonal category. AERSURFACE was applied with the instructions provided in the AERSURFACE User's Guide (EPA, 2013).

The current version of AERSURFACE (Version 13016) supports the use of land cover data from the USGS National Land Cover Data 1992 archives (NLCD92). The NLCD92 archive provides data at a spatial resolution of 30 meters based on a 21-category classification scheme applied over the continental U.S. Visual inspection of recent satellite images in the area of Plant Barry and Mobile Regional Airport (shown in Figures I-1 and I-2 respectively), compared to the 1992 land cover images (shown in Figures I-3 and I-4) indicate that there have been no significant changes in land use cover confirming the use of the 1992 data was reasonable. Figures I-5 and I-6 show the near-field view of the 1km circle, with the 12 land use sectors surrounding Plant Barry and Mobile Regional Airport.

For the surface roughness length comparison, the 1km area surrounding Plant Barry was divided into the same AERSURFACE default 12 sectors used for the Mobile Regional Airport.

In AERSURFACE the various land cover categories are linked to a set of seasonal surface characteristics. As such, AERSURFACE requires specification of the seasonal category for each month of the year. The following five seasonal categories are offered by AERSURFACE:

1. Midsummer with lush vegetation.
2. Autumn with unharvested cropland.
3. Late autumn after frost and harvest, or winter with no snow.
4. Winter with continuous snow on ground.
5. Transitional spring with partial green coverage or short annuals.

The seasonal designations for the AERSURFACE analysis surrounding Plant Barry were made consistent with the designations made by ADEM when processing the land use surrounding Mobile Regional Airport. Note that since there were no months with continuous snow cover, seasonal category 4 was not applicable. The monthly designations are summarized in Table I-1.

In addition, for Bowen ratio the land use values are linked to three categories of surface moisture corresponding to average, wet and dry conditions. As with the seasonal designations, the surface moisture conditions were provided with the ADEM-processed meteorological data for Mobile Regional Airport. The surface moisture conditions are summarized in Table I-2.

A comparison of the average land use characteristics over the five-year meteorological period (2014-2018) for Mobile Regional Airport and the Project site (shown in Tables I-3 and I-4 respectively) shows significant differences in both the Bowen ratio and the surface roughness. Even though the winds are considered representative, due to these substantial differences in the land use characteristics, land use surrounding the Mobile Regional Airport cannot be considered representative of the Plant Barry site. Therefore, dispersion modeling was conducted using two meteorological data sets; the first using the land use characteristics surrounding Mobile Regional Airport and the second using the land use characteristics surrounding the Plant Barry site (SITE).

AERMET Stage 3 input files and merge files (merged surface and upper air data created during Stage 2 of AERMET) for the five meteorological years (2014-2018) processed with AERMET Version 19191 and provided by ADEM, were used to process the second meteorological data set using the SITE land use characteristics using AERMET Version 19191. These meteorological data files, along with those provided by ADEM (which were processed using land use surrounding the airport), were both used in the modeling assessment.

Table I-1 Alabama Seasonal Categories

Category	Season Description	Months
1	Mid-summer with lush vegetation	Jun, Jul, Aug, Sep
2	Autumn with un-harvested cropland	Oct, Nov
3	Late autumn after frost or winter with no snow cover	Dec, Jan, Feb
4	Winter with continuous snow cover	NA
5	Transitional spring with partial green coverage or short annuals	Mar, Apr, May

Table I-2 Surface Moisture Conditions

Location	2014	2015	2016	2017	2018
Mobile (MOB)	Average	Wet	Average	Wet	Average

Table I-3 AERSURFACE Output for the Plant Barry Site (SITE)

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	Sector	Albedo	Bowen Ratio	Surface Roughness (m)	Albedo	Bowen Ratio	Surface Roughness (m)
1	1	0.14	0.47	0.664	0.14	0.22	0.664
1	2	0.14	0.47	0.602	0.14	0.22	0.602
1	3	0.14	0.47	0.515	0.14	0.22	0.515
1	4	0.14	0.47	0.489	0.14	0.22	0.489
1	5	0.14	0.47	1.146	0.14	0.22	1.146
1	6	0.14	0.47	1.08	0.14	0.22	1.08
1	7	0.14	0.47	0.988	0.14	0.22	0.988
1	8	0.14	0.47	0.944	0.14	0.22	0.944
1	9	0.14	0.47	0.782	0.14	0.22	0.782
1	10	0.14	0.47	0.873	0.14	0.22	0.873
1	11	0.14	0.47	0.735	0.14	0.22	0.735
1	12	0.14	0.47	0.746	0.14	0.22	0.746
2	1	0.14	0.47	0.664	0.14	0.22	0.664
2	2	0.14	0.47	0.602	0.14	0.22	0.602
2	3	0.14	0.47	0.515	0.14	0.22	0.515
2	4	0.14	0.47	0.489	0.14	0.22	0.489
2	5	0.14	0.47	1.146	0.14	0.22	1.146
2	6	0.14	0.47	1.08	0.14	0.22	1.08
2	7	0.14	0.47	0.988	0.14	0.22	0.988
2	8	0.14	0.47	0.944	0.14	0.22	0.944
2	9	0.14	0.47	0.782	0.14	0.22	0.782
2	10	0.14	0.47	0.873	0.14	0.22	0.873
2	11	0.14	0.47	0.735	0.14	0.22	0.735
2	12	0.14	0.47	0.746	0.14	0.22	0.746
3	1	0.14	0.41	0.7	0.14	0.21	0.7
3	2	0.14	0.41	0.671	0.14	0.21	0.671
3	3	0.14	0.41	0.604	0.14	0.21	0.604
3	4	0.14	0.41	0.554	0.14	0.21	0.554
3	5	0.14	0.41	1.214	0.14	0.21	1.214
3	6	0.14	0.41	1.166	0.14	0.21	1.166
3	7	0.14	0.41	1.054	0.14	0.21	1.054
3	8	0.14	0.41	1.018	0.14	0.21	1.018
3	9	0.14	0.41	0.854	0.14	0.21	0.854
3	10	0.14	0.41	0.915	0.14	0.21	0.915
3	11	0.14	0.41	0.802	0.14	0.21	0.802
3	12	0.14	0.41	0.825	0.14	0.21	0.825
4	1	0.14	0.41	0.7	0.14	0.21	0.7
4	2	0.14	0.41	0.671	0.14	0.21	0.671

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**
4	3	0.14	0.41	0.604	0.14	0.21	0.604
4	4	0.14	0.41	0.554	0.14	0.21	0.554
4	5	0.14	0.41	1.214	0.14	0.21	1.214
4	6	0.14	0.41	1.166	0.14	0.21	1.166
4	7	0.14	0.41	1.054	0.14	0.21	1.054
4	8	0.14	0.41	1.018	0.14	0.21	1.018
4	9	0.14	0.41	0.854	0.14	0.21	0.854
4	10	0.14	0.41	0.915	0.14	0.21	0.915
4	11	0.14	0.41	0.802	0.14	0.21	0.802
4	12	0.14	0.41	0.825	0.14	0.21	0.825
5	1	0.14	0.41	0.7	0.14	0.21	0.7
5	2	0.14	0.41	0.671	0.14	0.21	0.671
5	3	0.14	0.41	0.604	0.14	0.21	0.604
5	4	0.14	0.41	0.554	0.14	0.21	0.554
5	5	0.14	0.41	1.214	0.14	0.21	1.214
5	6	0.14	0.41	1.166	0.14	0.21	1.166
5	7	0.14	0.41	1.054	0.14	0.21	1.054
5	8	0.14	0.41	1.018	0.14	0.21	1.018
5	9	0.14	0.41	0.854	0.14	0.21	0.854
5	10	0.14	0.41	0.915	0.14	0.21	0.915
5	11	0.14	0.41	0.802	0.14	0.21	0.802
5	12	0.14	0.41	0.825	0.14	0.21	0.825
6	1	0.14	0.26	0.767	0.14	0.17	0.767
6	2	0.14	0.26	0.733	0.14	0.17	0.733
6	3	0.14	0.26	0.793	0.14	0.17	0.793
6	4	0.14	0.26	0.773	0.14	0.17	0.773
6	5	0.14	0.26	1.284	0.14	0.17	1.284
6	6	0.14	0.26	1.232	0.14	0.17	1.232
6	7	0.14	0.26	1.105	0.14	0.17	1.105
6	8	0.14	0.26	1.098	0.14	0.17	1.098
6	9	0.14	0.26	0.923	0.14	0.17	0.923
6	10	0.14	0.26	0.952	0.14	0.17	0.952
6	11	0.14	0.26	0.907	0.14	0.17	0.907
6	12	0.14	0.26	0.944	0.14	0.17	0.944
7	1	0.14	0.26	0.767	0.14	0.17	0.767
7	2	0.14	0.26	0.733	0.14	0.17	0.733
7	3	0.14	0.26	0.793	0.14	0.17	0.793
7	4	0.14	0.26	0.773	0.14	0.17	0.773
7	5	0.14	0.26	1.284	0.14	0.17	1.284
7	6	0.14	0.26	1.232	0.14	0.17	1.232
7	7	0.14	0.26	1.105	0.14	0.17	1.105
7	8	0.14	0.26	1.098	0.14	0.17	1.098
7	9	0.14	0.26	0.923	0.14	0.17	0.923
7	10	0.14	0.26	0.952	0.14	0.17	0.952
7	11	0.14	0.26	0.907	0.14	0.17	0.907
7	12	0.14	0.26	0.944	0.14	0.17	0.944
8	1	0.14	0.26	0.767	0.14	0.17	0.767

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**
8	2	0.14	0.26	0.733	0.14	0.17	0.733
8	3	0.14	0.26	0.793	0.14	0.17	0.793
8	4	0.14	0.26	0.773	0.14	0.17	0.773
8	5	0.14	0.26	1.284	0.14	0.17	1.284
8	6	0.14	0.26	1.232	0.14	0.17	1.232
8	7	0.14	0.26	1.105	0.14	0.17	1.105
8	8	0.14	0.26	1.098	0.14	0.17	1.098
8	9	0.14	0.26	0.923	0.14	0.17	0.923
8	10	0.14	0.26	0.952	0.14	0.17	0.952
8	11	0.14	0.26	0.907	0.14	0.17	0.907
8	12	0.14	0.26	0.944	0.14	0.17	0.944
9	1	0.14	0.26	0.767	0.14	0.17	0.767
9	2	0.14	0.26	0.733	0.14	0.17	0.733
9	3	0.14	0.26	0.793	0.14	0.17	0.793
9	4	0.14	0.26	0.773	0.14	0.17	0.773
9	5	0.14	0.26	1.284	0.14	0.17	1.284
9	6	0.14	0.26	1.232	0.14	0.17	1.232
9	7	0.14	0.26	1.105	0.14	0.17	1.105
9	8	0.14	0.26	1.098	0.14	0.17	1.098
9	9	0.14	0.26	0.923	0.14	0.17	0.923
9	10	0.14	0.26	0.952	0.14	0.17	0.952
9	11	0.14	0.26	0.907	0.14	0.17	0.907
9	12	0.14	0.26	0.944	0.14	0.17	0.944
10	1	0.14	0.47	0.767	0.14	0.22	0.767
10	2	0.14	0.47	0.733	0.14	0.22	0.733
10	3	0.14	0.47	0.793	0.14	0.22	0.793
10	4	0.14	0.47	0.773	0.14	0.22	0.773
10	5	0.14	0.47	1.284	0.14	0.22	1.284
10	6	0.14	0.47	1.232	0.14	0.22	1.232
10	7	0.14	0.47	1.105	0.14	0.22	1.105
10	8	0.14	0.47	1.098	0.14	0.22	1.098
10	9	0.14	0.47	0.923	0.14	0.22	0.923
10	10	0.14	0.47	0.952	0.14	0.22	0.952
10	11	0.14	0.47	0.907	0.14	0.22	0.907
10	12	0.14	0.47	0.944	0.14	0.22	0.944
11	1	0.14	0.47	0.767	0.14	0.22	0.767
11	2	0.14	0.47	0.733	0.14	0.22	0.733
11	3	0.14	0.47	0.793	0.14	0.22	0.793
11	4	0.14	0.47	0.773	0.14	0.22	0.773
11	5	0.14	0.47	1.284	0.14	0.22	1.284
11	6	0.14	0.47	1.232	0.14	0.22	1.232
11	7	0.14	0.47	1.105	0.14	0.22	1.105
11	8	0.14	0.47	1.098	0.14	0.22	1.098
11	9	0.14	0.47	0.923	0.14	0.22	0.923
11	10	0.14	0.47	0.952	0.14	0.22	0.952
11	11	0.14	0.47	0.907	0.14	0.22	0.907
11	12	0.14	0.47	0.944	0.14	0.22	0.944

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**
12	1	0.14	0.47	0.664	0.14	0.22	0.664
12	2	0.14	0.47	0.602	0.14	0.22	0.602
12	3	0.14	0.47	0.515	0.14	0.22	0.515
12	4	0.14	0.47	0.489	0.14	0.22	0.489
12	5	0.14	0.47	1.146	0.14	0.22	1.146
12	6	0.14	0.47	1.08	0.14	0.22	1.08
12	7	0.14	0.47	0.988	0.14	0.22	0.988
12	8	0.14	0.47	0.944	0.14	0.22	0.944
12	9	0.14	0.47	0.782	0.14	0.22	0.782
12	10	0.14	0.47	0.873	0.14	0.22	0.873
12	11	0.14	0.47	0.735	0.14	0.22	0.735
12	12	0.14	0.47	0.746	0.14	0.22	0.746

Table I-4 AERSURFACE Output for Mobile Regional Airport

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	Sector	Albedo	Bowen Ratio	Surface Roughness (m)	Albedo	Bowen Ratio	Surface Roughness (m)
1	1	0.16	0.73	0.023	0.16	0.35	0.023
1	2	0.16	0.73	0.024	0.16	0.35	0.024
1	3	0.16	0.73	0.024	0.16	0.35	0.024
1	4	0.16	0.73	0.026	0.16	0.35	0.026
1	5	0.16	0.73	0.028	0.16	0.35	0.028
1	6	0.16	0.73	0.033	0.16	0.35	0.033
1	7	0.16	0.73	0.043	0.16	0.35	0.043
1	8	0.16	0.73	0.036	0.16	0.35	0.036
1	9	0.16	0.73	0.051	0.16	0.35	0.051
1	10	0.16	0.73	0.046	0.16	0.35	0.046
1	11	0.16	0.73	0.215	0.16	0.35	0.215
1	12	0.16	0.73	0.021	0.16	0.35	0.021
2	1	0.16	0.73	0.023	0.16	0.35	0.023
2	2	0.16	0.73	0.024	0.16	0.35	0.024
2	3	0.16	0.73	0.024	0.16	0.35	0.024
2	4	0.16	0.73	0.026	0.16	0.35	0.026
2	5	0.16	0.73	0.028	0.16	0.35	0.028
2	6	0.16	0.73	0.033	0.16	0.35	0.033
2	7	0.16	0.73	0.043	0.16	0.35	0.043
2	8	0.16	0.73	0.036	0.16	0.35	0.036
2	9	0.16	0.73	0.051	0.16	0.35	0.051
2	10	0.16	0.73	0.046	0.16	0.35	0.046
2	11	0.16	0.73	0.215	0.16	0.35	0.215
2	12	0.16	0.73	0.021	0.16	0.35	0.021
3	1	0.14	0.48	0.029	0.14	0.26	0.029
3	2	0.14	0.48	0.03	0.14	0.26	0.03
3	3	0.14	0.48	0.03	0.14	0.26	0.03
3	4	0.14	0.48	0.032	0.14	0.26	0.032
3	5	0.14	0.48	0.034	0.14	0.26	0.034
3	6	0.14	0.48	0.038	0.14	0.26	0.038
3	7	0.14	0.48	0.048	0.14	0.26	0.048
3	8	0.14	0.48	0.046	0.14	0.26	0.046
3	9	0.14	0.48	0.068	0.14	0.26	0.068
3	10	0.14	0.48	0.062	0.14	0.26	0.062
3	11	0.14	0.48	0.273	0.14	0.26	0.273
3	12	0.14	0.48	0.028	0.14	0.26	0.028
4	1	0.14	0.48	0.029	0.14	0.26	0.029
4	2	0.14	0.48	0.03	0.14	0.26	0.03
4	3	0.14	0.48	0.03	0.14	0.26	0.03
4	4	0.14	0.48	0.032	0.14	0.26	0.032
4	5	0.14	0.48	0.034	0.14	0.26	0.034
4	6	0.14	0.48	0.038	0.14	0.26	0.038
4	7	0.14	0.48	0.048	0.14	0.26	0.048
4	8	0.14	0.48	0.046	0.14	0.26	0.046
4	9	0.14	0.48	0.068	0.14	0.26	0.068

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**
4	10	0.14	0.48	0.062	0.14	0.26	0.062
4	11	0.14	0.48	0.273	0.14	0.26	0.273
4	12	0.14	0.48	0.028	0.14	0.26	0.028
5	1	0.14	0.48	0.029	0.14	0.26	0.029
5	2	0.14	0.48	0.03	0.14	0.26	0.03
5	3	0.14	0.48	0.03	0.14	0.26	0.03
5	4	0.14	0.48	0.032	0.14	0.26	0.032
5	5	0.14	0.48	0.034	0.14	0.26	0.034
5	6	0.14	0.48	0.038	0.14	0.26	0.038
5	7	0.14	0.48	0.048	0.14	0.26	0.048
5	8	0.14	0.48	0.046	0.14	0.26	0.046
5	9	0.14	0.48	0.068	0.14	0.26	0.068
5	10	0.14	0.48	0.062	0.14	0.26	0.062
5	11	0.14	0.48	0.273	0.14	0.26	0.273
5	12	0.14	0.48	0.028	0.14	0.26	0.028
6	1	0.16	0.4	0.035	0.16	0.26	0.035
6	2	0.16	0.4	0.035	0.16	0.26	0.035
6	3	0.16	0.4	0.035	0.16	0.26	0.035
6	4	0.16	0.4	0.037	0.16	0.26	0.037
6	5	0.16	0.4	0.038	0.16	0.26	0.038
6	6	0.16	0.4	0.043	0.16	0.26	0.043
6	7	0.16	0.4	0.052	0.16	0.26	0.052
6	8	0.16	0.4	0.067	0.16	0.26	0.067
6	9	0.16	0.4	0.134	0.16	0.26	0.134
6	10	0.16	0.4	0.127	0.16	0.26	0.127
6	11	0.16	0.4	0.376	0.16	0.26	0.376
6	12	0.16	0.4	0.035	0.16	0.26	0.035
7	1	0.16	0.4	0.035	0.16	0.26	0.035
7	2	0.16	0.4	0.035	0.16	0.26	0.035
7	3	0.16	0.4	0.035	0.16	0.26	0.035
7	4	0.16	0.4	0.037	0.16	0.26	0.037
7	5	0.16	0.4	0.038	0.16	0.26	0.038
7	6	0.16	0.4	0.043	0.16	0.26	0.043
7	7	0.16	0.4	0.052	0.16	0.26	0.052
7	8	0.16	0.4	0.067	0.16	0.26	0.067
7	9	0.16	0.4	0.134	0.16	0.26	0.134
7	10	0.16	0.4	0.127	0.16	0.26	0.127
7	11	0.16	0.4	0.376	0.16	0.26	0.376
7	12	0.16	0.4	0.035	0.16	0.26	0.035
8	1	0.16	0.4	0.035	0.16	0.26	0.035
8	2	0.16	0.4	0.035	0.16	0.26	0.035
8	3	0.16	0.4	0.035	0.16	0.26	0.035
8	4	0.16	0.4	0.037	0.16	0.26	0.037
8	5	0.16	0.4	0.038	0.16	0.26	0.038
8	6	0.16	0.4	0.043	0.16	0.26	0.043
8	7	0.16	0.4	0.052	0.16	0.26	0.052
8	8	0.16	0.4	0.067	0.16	0.26	0.067

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**
8	9	0.16	0.4	0.134	0.16	0.26	0.134
8	10	0.16	0.4	0.127	0.16	0.26	0.127
8	11	0.16	0.4	0.376	0.16	0.26	0.376
8	12	0.16	0.4	0.035	0.16	0.26	0.035
9	1	0.16	0.4	0.035	0.16	0.26	0.035
9	2	0.16	0.4	0.035	0.16	0.26	0.035
9	3	0.16	0.4	0.035	0.16	0.26	0.035
9	4	0.16	0.4	0.037	0.16	0.26	0.037
9	5	0.16	0.4	0.038	0.16	0.26	0.038
9	6	0.16	0.4	0.043	0.16	0.26	0.043
9	7	0.16	0.4	0.052	0.16	0.26	0.052
9	8	0.16	0.4	0.067	0.16	0.26	0.067
9	9	0.16	0.4	0.134	0.16	0.26	0.134
9	10	0.16	0.4	0.127	0.16	0.26	0.127
9	11	0.16	0.4	0.376	0.16	0.26	0.376
9	12	0.16	0.4	0.035	0.16	0.26	0.035
10	1	0.16	0.73	0.029	0.16	0.35	0.029
10	2	0.16	0.73	0.03	0.16	0.35	0.03
10	3	0.16	0.73	0.03	0.16	0.35	0.03
10	4	0.16	0.73	0.032	0.16	0.35	0.032
10	5	0.16	0.73	0.034	0.16	0.35	0.034
10	6	0.16	0.73	0.038	0.16	0.35	0.038
10	7	0.16	0.73	0.048	0.16	0.35	0.048
10	8	0.16	0.73	0.06	0.16	0.35	0.06
10	9	0.16	0.73	0.124	0.16	0.35	0.124
10	10	0.16	0.73	0.117	0.16	0.35	0.117
10	11	0.16	0.73	0.353	0.16	0.35	0.353
10	12	0.16	0.73	0.029	0.16	0.35	0.029
11	1	0.16	0.73	0.029	0.16	0.35	0.029
11	2	0.16	0.73	0.03	0.16	0.35	0.03
11	3	0.16	0.73	0.03	0.16	0.35	0.03
11	4	0.16	0.73	0.032	0.16	0.35	0.032
11	5	0.16	0.73	0.034	0.16	0.35	0.034
11	6	0.16	0.73	0.038	0.16	0.35	0.038
11	7	0.16	0.73	0.048	0.16	0.35	0.048
11	8	0.16	0.73	0.06	0.16	0.35	0.06
11	9	0.16	0.73	0.124	0.16	0.35	0.124
11	10	0.16	0.73	0.117	0.16	0.35	0.117
11	11	0.16	0.73	0.353	0.16	0.35	0.353
11	12	0.16	0.73	0.029	0.16	0.35	0.029
12	1	0.16	0.73	0.023	0.16	0.35	0.023
12	2	0.16	0.73	0.024	0.16	0.35	0.024
12	3	0.16	0.73	0.024	0.16	0.35	0.024
12	4	0.16	0.73	0.026	0.16	0.35	0.026
12	5	0.16	0.73	0.028	0.16	0.35	0.028
12	6	0.16	0.73	0.033	0.16	0.35	0.033
12	7	0.16	0.73	0.043	0.16	0.35	0.043

		Average Surface Moisture (2014,2016,2018)			Wet Surface Moisture (2015,2017)		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**	**Albedo**	**Bowen Ratio**	**Surface Roughness (m)**
12	8	0.16	0.73	0.036	0.16	0.35	0.036
12	9	0.16	0.73	0.051	0.16	0.35	0.051
12	10	0.16	0.73	0.046	0.16	0.35	0.046
12	11	0.16	0.73	0.215	0.16	0.35	0.215
12	12	0.16	0.73	0.021	0.16	0.35	0.021

Figure I-1 Aerial Photograph of the 10 km x 10 km Area Surrounding the Plant Barry Site

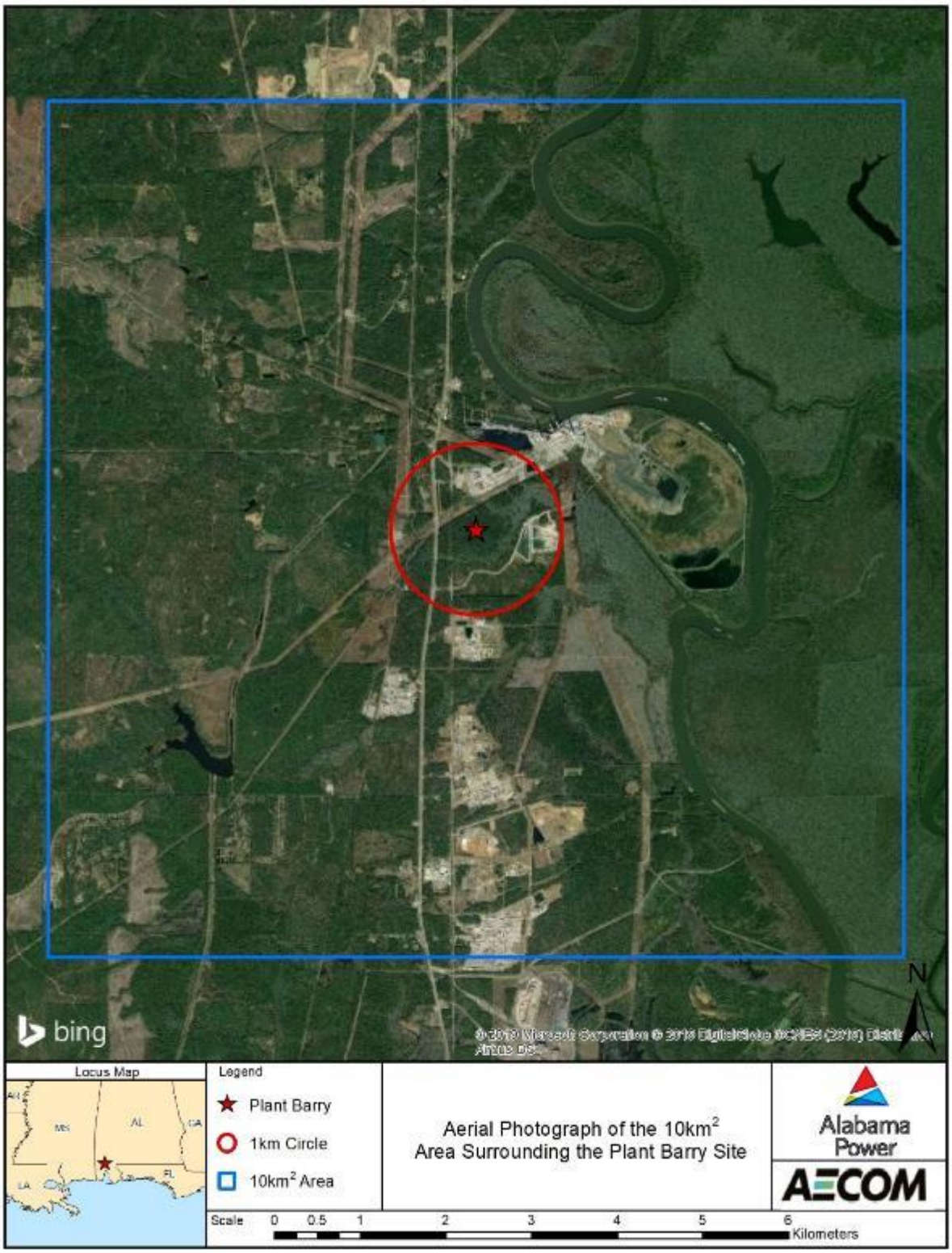


Figure I-2 Aerial Photograph of the 10 km x 10 km Area Surrounding Mobile Regional Airport

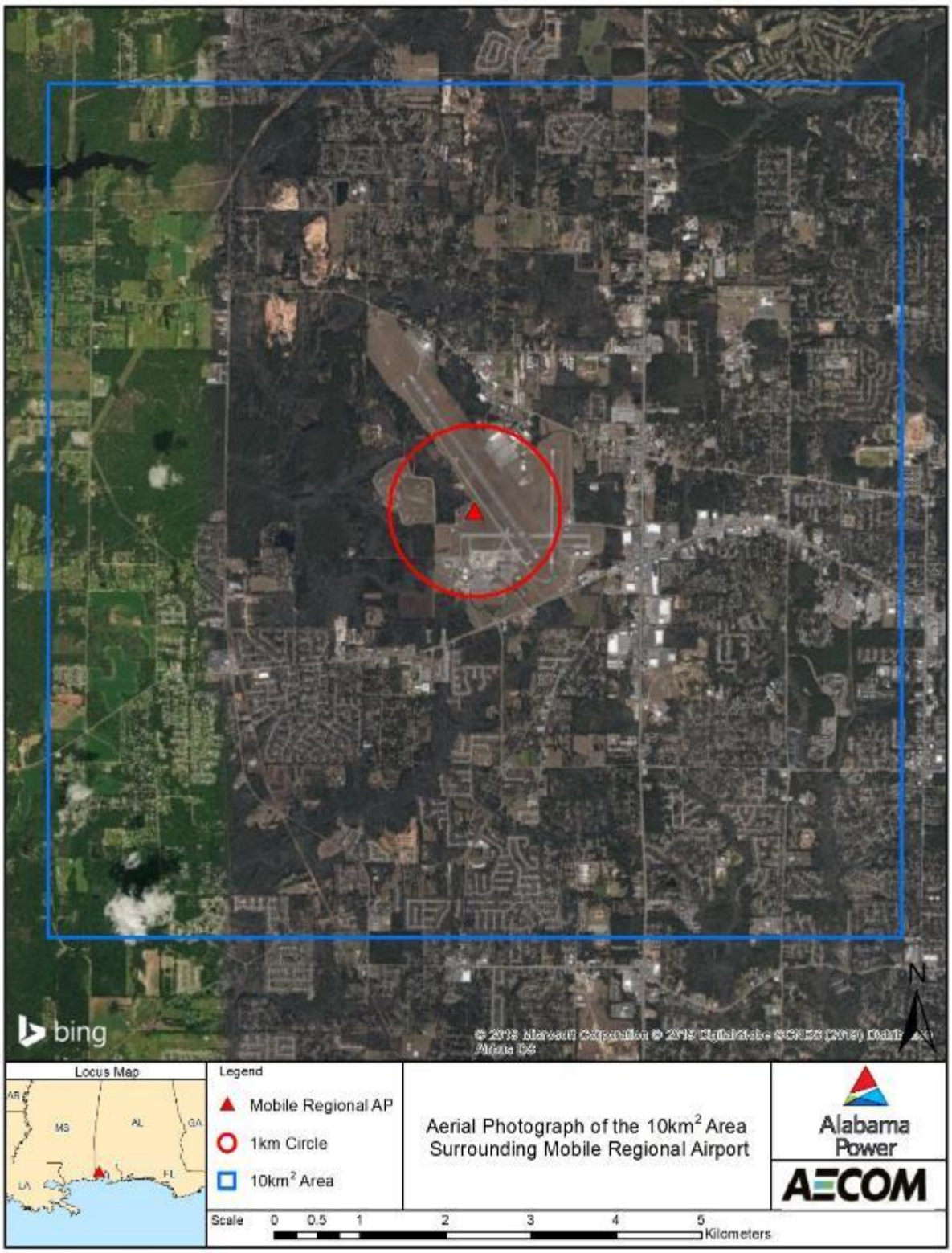


Figure I-3 1992 NLCD Data for the 10 km x 10 km Area Surrounding the Plant Barry Site

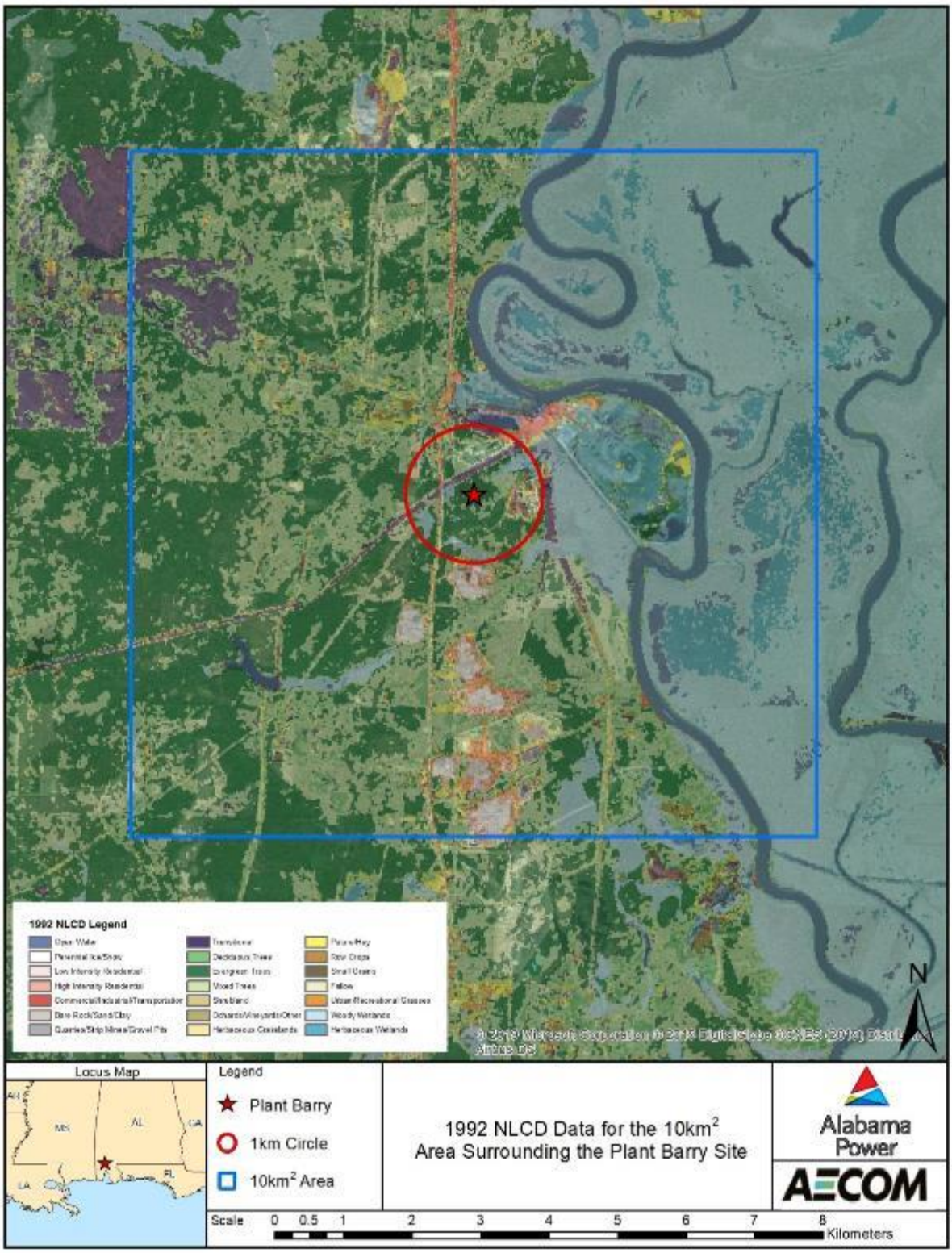


Figure I-4 1992 NLCD Data for the 10 km x 10 km Area Surrounding Mobile Regional Airport

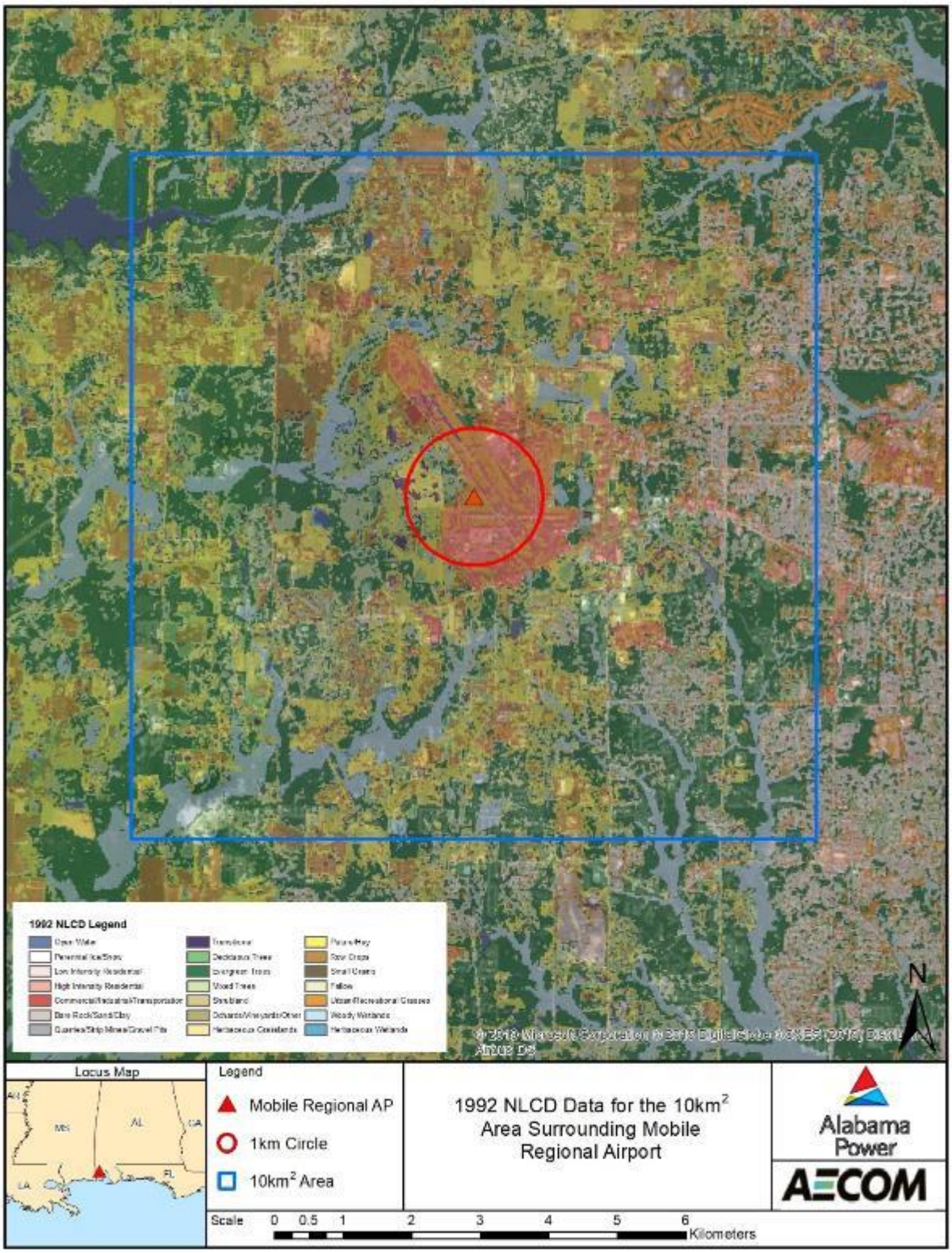


Figure I-5 Near-Field 1992 NLCD Data of the 1 km Area Surrounding the Plant Barry Site

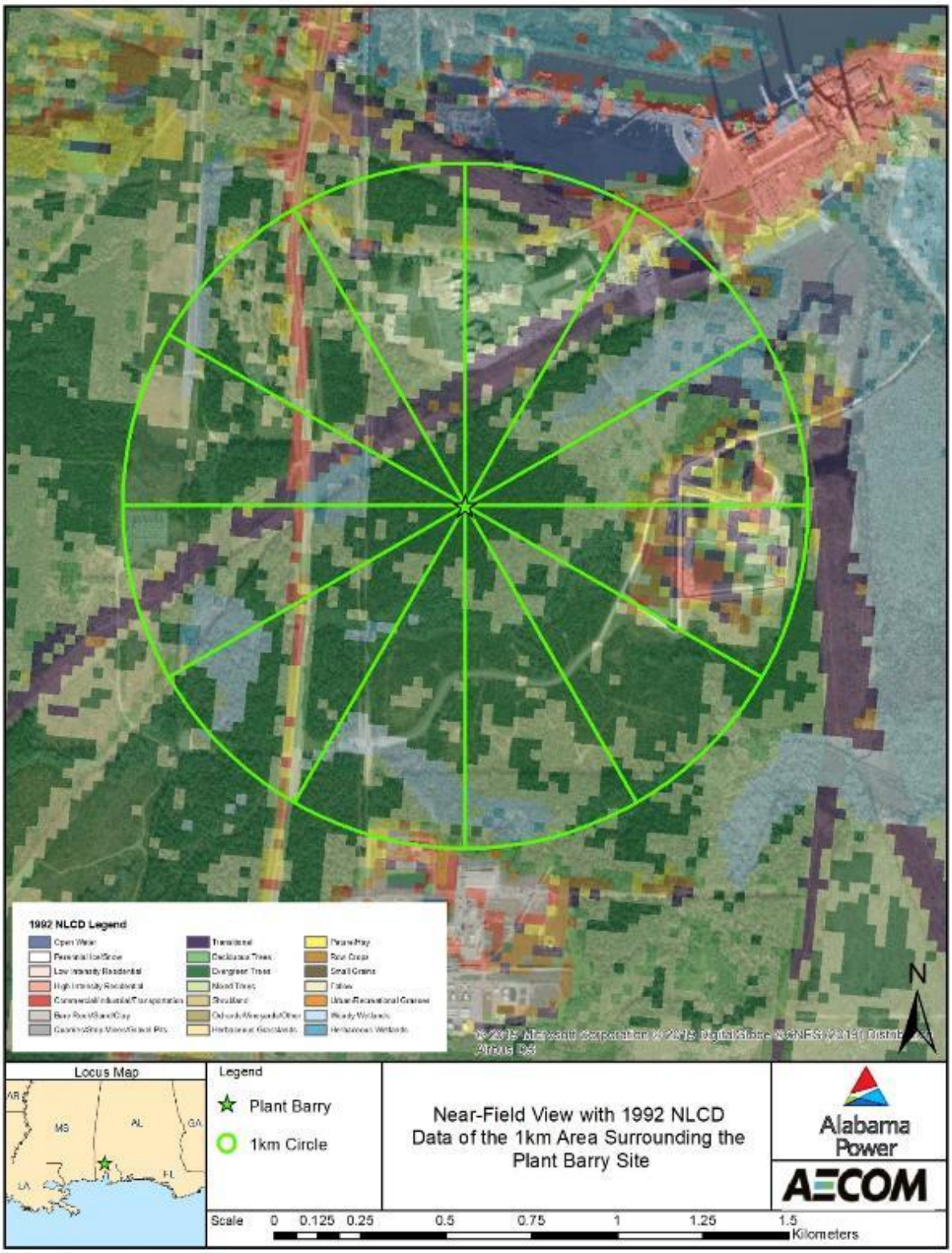
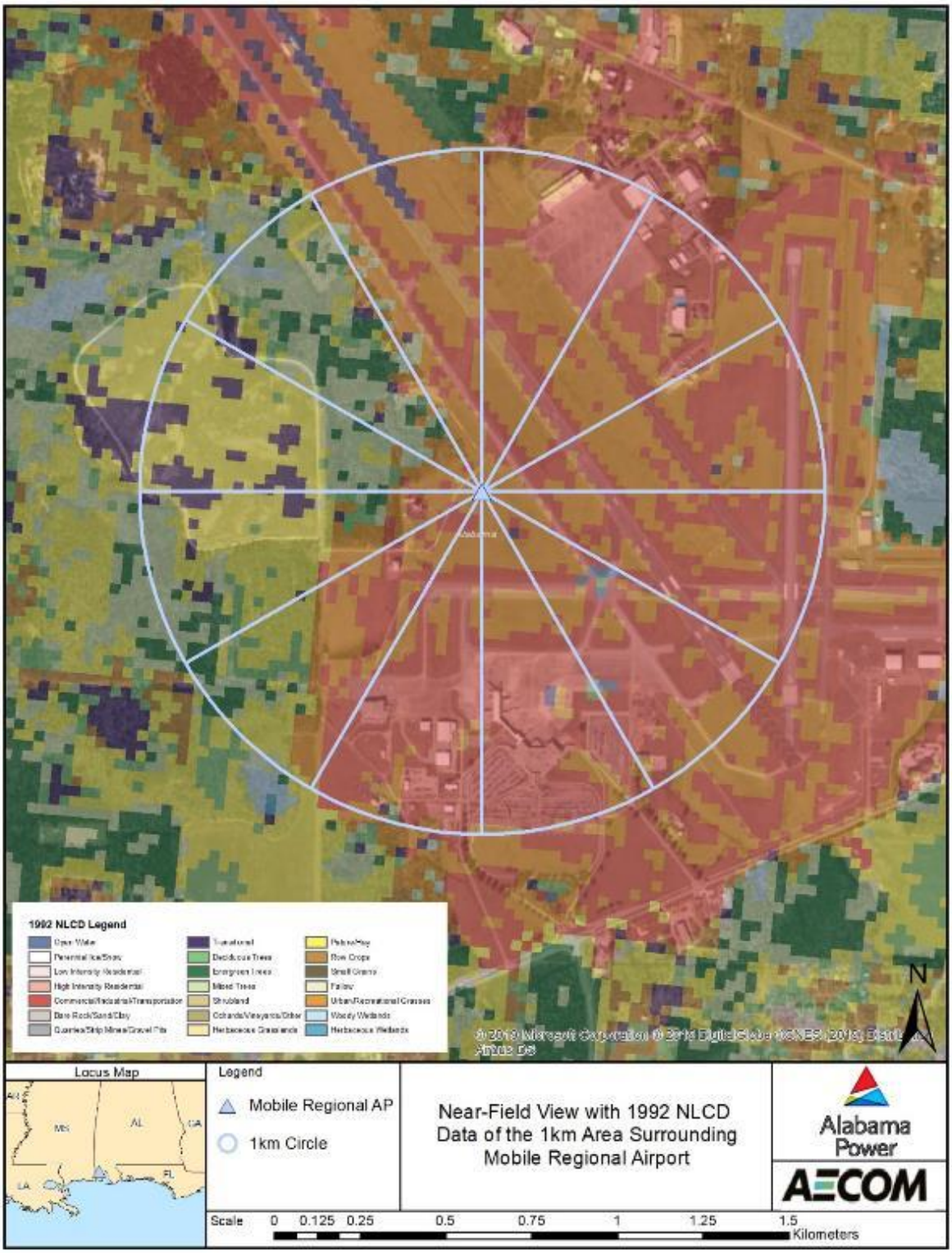


Figure I-6 Near-Field 1992 NLCD Data of the 1 km Area Surrounding Mobile Regional Airport



Appendix J

AQS Reports

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

User ID: XDADAMS

DESIGN VALUE REPORT

Report Request ID: 1772950 Report Code: AMP480 Sep. 4, 2019

GEOGRAPHIC SELECTIONS

Tribal Code	State	County	Site	Parameter	POC	City	AQCR	UAR	CBSA	CSA	EPA Region
	01	097	0003								

PROTOCOL SELECTIONS

Parameter Classification	Parameter	Method	Duration
DESIGN VALUE	44201		
DESIGN VALUE	88101		

SELECTED OPTIONS

Option Type	Option Value
WORKFILE DELIMITER	,
SINGLE EVENT PROCESSING	EXCLUDE REGIONALLY CONCURRED EVENTS
QUARTERLY DATA IN WORKFILE	NO
AGENCY ROLE	PQAO
USER SITE METADATA	STREET ADDRESS
MERGE PDF FILES	YES
USE LINKED SITES	YES

DATE CRITERIA

Start Date	End Date
2016	2018

APPLICABLE STANDARDS

Standard Description
Ozone 8-hour 2015
PM25 24-hour 2012
PM25 Annual 2012

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
PRELIMINARY DESIGN VALUE REPORT

Report Date: Sep. 4, 2019

Pollutant: Ozone(44201)
Standard Units: Parts per million(007)
NAAQS Standard: Ozone 8-hour 2015
Statistic: Annual 4th Maximum **Level:** .07

Design Value Year: 2016

REPORT EXCLUDES MEASUREMENTS WITH REGIONALLY CONCURRED EVENT FLAGS.

State: Alabama

Site ID	Poc	STREET ADDRESS	2016 Valid Days	2016 Percent Complete	2016 4th Max	2016 Cert& Eval	2015 Valid Days	2015 Percent Complete	2015 4th Max	2015 Cert& Eval	2014 Valid Days	2014 Percent Complete	2014 4th Max	2014 Cert& Eval	3 - Year Percent Complete	3 - Year Design Value	D. V. Validity
01-097-0003		Iroquois and Azalea, CHICKASAW, MOBILE CO., ALABAMA	231	94	.062	Y	235	96	.060	Y	228	93	.068	Y	94	.063	Y

Notes: 1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
PRELIMINARY DESIGN VALUE REPORT

Report Date: Sep. 4, 2019

Pollutant: Ozone(44201)
Standard Units: Parts per million(007)
NAAQS Standard: Ozone 8-hour 2015
Statistic: Annual 4th Maximum **Level:** .07

Design Value Year: 2017

REPORT EXCLUDES MEASUREMENTS WITH REGIONALLY CONCURRED EVENT FLAGS.

State: Alabama

			2017				2016				2015				3 - Year		
Site ID	Poc	STREET ADDRESS	Valid Days	Percent Complete	4th Max	Cert& Eval	Valid Days	Percent Complete	4th Max	Cert& Eval	Valid Days	Percent Complete	4th Max	Cert& Eval	Percent Complete	Design Value	D. V. Validity
01-097-0003		Iroquois and Azalea, CHICKASAW, MOBILE CO., ALABAMA	226	92	.065	Y	231	94	.062	Y	235	96	.060	Y	94	.062	Y

Notes:
1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
PRELIMINARY DESIGN VALUE REPORT

Report Date: Sep. 4, 2019

Pollutant: Ozone(44201)
Standard Units: Parts per million(007)
NAAQS Standard: Ozone 8-hour 2015
Statistic: Annual 4th Maximum **Level:** .07

Design Value Year: 2018

REPORT EXCLUDES MEASUREMENTS WITH REGIONALLY CONCURRED EVENT FLAGS.

State: Alabama

Site ID	Poc	STREET ADDRESS	2018 Valid Days	2018 Percent Complete	2018 4th Max	2018 Cert& Eval	2017 Valid Days	2017 Percent Complete	2017 4th Max	2017 Cert& Eval	2016 Valid Days	2016 Percent Complete	2016 4th Max	2016 Cert& Eval	3 - Year Percent Complete	3 - Year Design Value	D. V. Validity
01-097-0003		Iroquois and Azalea, CHICKASAW, MOBILE CO., ALABAMA	232	95	.065	Y	226	92	.065	Y	231	94	.062	Y	94	.064	Y

Notes:
1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

Pollutant: Site-LevelPM2.5 - Local Conditions(88101)
Standard Units: Micrograms/cubic meter (LC)(105)
NAAQS Standard: PM25 24-hour 2012 / PM25 Annual 2012
Statistic: Annual Weighted Mean **Level:** 12
Statistic: Annual 98th Percentile **Level:** 35

Design Value Year: 2016

REPORT EXCLUDES MEASUREMENTS WITH REGIONALLY CONCURRED EVENT FLAGS.

State Name: Alabama

Site_ID / STREET ADDRESS	2016 Cred. Days	2016 Comp. Qrtrs	2016 98th Perctil	2016 Wtd. Mean	2016 Cert& Eval	2015 Cred. Days	2015 Comp. Qrtrs	2015 98th Perctil	2015 Wtd. Mean	2015 Cert& Eval	2014 Cred. Days	2014 Comp. Qrtrs	2014 98th Perctil	2014 Wtd. Mean	2014 Cert& Eval	24-Hour Design Value	24-Hour Valid Ind.	Annual Design Value	Annual Valid Ind.
01-097-0003	121	4	15.7	8.1	Y	115	4	19.0	8.4	Y	118	4	18.0	9.0	Y	18	Y	8.5	Y
Iroquois and Azalea, CHICKASAW, MOBILE CO., ALABAMA																			

Notes:
1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

Pollutant: Site-LevelPM2.5 - Local Conditions(88101)
Standard Units: Micrograms/cubic meter (LC)(105)
NAAQS Standard: PM25 24-hour 2012 / PM25 Annual 2012
Statistic: Annual Weighted Mean **Level:** 12
Statistic: Annual 98th Percentile **Level:** 35

Design Value Year: 2017

REPORT EXCLUDES MEASUREMENTS WITH REGIONALLY CONCURRED EVENT FLAGS.

State Name: Alabama

Site_ID / STREET ADDRESS	2017					2016					2015					24-Hour		Annual	
	Cred. Days	Comp. Qrtrs	98th Perctil	Wtd. Mean	Cert& Eval	Cred. Days	Comp. Qrtrs	98th Perctil	Wtd. Mean	Cert& Eval	Cred. Days	Comp. Qrtrs	98th Perctil	Wtd. Mean	Cert& Eval	Design Value	Valid Ind.	Design Value	Valid Ind.
01-097-0003	111	4	17.4	8.0	Y	121	4	15.7	8.1	Y	115	4	19.0	8.4	Y	17	Y	8.1	Y
Iroquois and Azalea, CHICKASAW, MOBILE CO., ALABAMA																			

Notes:
1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

Pollutant: Site-LevelPM2.5 - Local Conditions(88101)
Standard Units: Micrograms/cubic meter (LC)(105)
NAAQS Standard: PM25 24-hour 2012 / PM25 Annual 2012
Statistic: Annual Weighted Mean **Level:** 12
Statistic: Annual 98th Percentile **Level:** 35

Design Value Year: 2018

REPORT EXCLUDES MEASUREMENTS WITH REGIONALLY CONCURRED EVENT FLAGS.

State Name: Alabama

Site_ID / STREET ADDRESS	2018 Cred. Days	2018 Comp. Qrtrs	2018 98th Perctil	2018 Wtd. Mean	2018 Cert& Eval	2017 Cred. Days	2017 Comp. Qrtrs	2017 98th Perctil	2017 Wtd. Mean	2017 Cert& Eval	2016 Cred. Days	2016 Comp. Qrtrs	2016 98th Perctil	2016 Wtd. Mean	2016 Cert& Eval	24-Hour Design Value	24-Hour Valid Ind.	Annual Design Value	Annual Valid Ind.
01-097-0003	111	4	16.9	8.1	Y	111	4	17.4	8.0	Y	121	4	15.7	8.1	Y	17	Y	8.1	Y
Iroquois and Azalea, CHICKASAW, MOBILE CO., ALABAMA																			

Notes:
1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

CERTIFICATION EVALUATION AND CONCURRENCE FLAG MEANINGS

FLAG	MEANING
M	The monitoring organization has revised data from this monitor since the most recent certification letter received from the state.
N	The certifying agency has submitted the certification letter and required summary reports, but the certifying agency and/or EPA has determined that issues regarding the quality of the ambient concentration data cannot be resolved due to data completeness, the lack of performed quality assurance checks or the results of uncertainty statistics shown in the AMP255 report or the certification and quality assurance report.
S	The certifying agency has submitted the certification letter and required summary reports. A value of "S" conveys no Regional assessment regarding data quality per se. This flag will remain until the Region provides an "N" or "Y" concurrence flag.
U	Uncertified. The certifying agency did not submit a required certification letter and summary reports for this monitor even though the due date has passed, or the state's certification letter specifically did not apply the certification to this monitor.
X	Certification is not required by 40 CFR 58.15 and no conditions apply to be the basis for assigning another flag value
Y	The certifying agency has submitted a certification letter, and EPA has no unresolved reservations about data quality (after reviewing the letter, the attached summary reports, the amount of quality assurance data submitted to AQS, the quality statistics, and the highest reported concentrations).

Notes:
1. Computed design values are a snapshot of the data at the time the report was run (may not be all data for year).
2. Some PM2.5 24-hour DVs for incomplete data that are marked invalid here may be marked valid in the Official report due to additional analysis.
3. Annual Values not meeting completeness criteria are marked with an asterisk ('*').

Monitor Values Report

Geographic Area: Paulding County, GA
Pollutant: NO2
Year: 2013
Exceptional Events: Included (if any)
Note: The * indicates the mean does not satisfy minimum data completeness criteria.

Obs	First Max 1hr	Second Max 1hr	98th Percentile	Annual Mean	Exc Events	Monitor Number	Site ID	Address	City	County	State	EPA Region
8358	24	22	18	2.73	None	1	132230003	King Farm, 160 Ralph King Path, Rockmart, Georgia, 30153	Not in a City	Paulding	GA	04

Get detailed information about this report, including column descriptions, at https://www.epa.gov/outdoor-air-quality-data/about-air-data-reports#mon

AirData reports are produced from a direct query of the AQS Data Mart. The data represent the best and most recent information available to EPA from state agencies. However, some values may be absent due to incomplete reporting, and some values may change due to quality assurance activities. The AQS database is updated by state, local, and tribal organizations who own and submit the data.

Readers are cautioned not to rank order geographic areas based on AirData reports. Air pollution levels measured at a particular monitoring site are not necessarily representative of the air quality for an entire county or urban area.

This report is based on monitor-level summary statistics. Air quality standards for some pollutants (PM2.5 and Pb) allow for combining data from multiple monitors into a site-level summary statistic that can be compared to the standard. In those cases, the site-level statistics may differ from the monitor-level statistics upon which this report is based.

Source: U.S. EPA AirData <https://www.epa.gov/air-data>
Generated: November 25, 2019

Monitor Values Report

Geographic Area: Paulding County, GA
Pollutant: NO2
Year: 2014
Exceptional Events: Included (if any)
Note: The * indicates the mean does not satisfy minimum data completeness criteria.

Obs	First Max 1hr	Second Max 1hr	98th Percentile	Annual Mean	Exc Events	Monitor Number	Site ID	Address	City	County	State	EPA Region
8259	23	21	17	2.63	None	1	132230003	King Farm, 160 Ralph King Path, Rockmart, Georgia, 30153	Not in a City	Paulding	GA	04

Get detailed information about this report, including column descriptions, at https://www.epa.gov/outdoor-air-quality-data/about-air-data-reports#mon

AirData reports are produced from a direct query of the AQS Data Mart. The data represent the best and most recent information available to EPA from state agencies. However, some values may be absent due to incomplete reporting, and some values may change due to quality assurance activities. The AQS database is updated by state, local, and tribal organizations who own and submit the data.

Readers are cautioned not to rank order geographic areas based on AirData reports. Air pollution levels measured at a particular monitoring site are not necessarily representative of the air quality for an entire county or urban area.

This report is based on monitor-level summary statistics. Air quality standards for some pollutants (PM2.5 and Pb) allow for combining data from multiple monitors into a site-level summary statistic that can be compared to the standard. In those cases, the site-level statistics may differ from the monitor-level statistics upon which this report is based.

Source: U.S. EPA AirData <https://www.epa.gov/air-data>
Generated: November 25, 2019

Monitor Values Report

Geographic Area: Paulding County, GA
Pollutant: NO2
Year: 2015
Exceptional Events: Included (if any)
Note: The * indicates the mean does not satisfy minimum data completeness criteria.

Obs	First Max 1hr	Second Max 1hr	98th Percentile	Annual Mean	Exc Events	Monitor Number	Site ID	Address	City	County	State	EPA Region
8023	17	16	13	1.88	None	1	132230003	King Farm, 160 Ralph King Path, Rockmart, Georgia, 30153	Not in a City	Paulding	GA	04

Get detailed information about this report, including column descriptions, at https://www.epa.gov/outdoor-air-quality-data/about-air-data-reports#mon

AirData reports are produced from a direct query of the AQS Data Mart. The data represent the best and most recent information available to EPA from state agencies. However, some values may be absent due to incomplete reporting, and some values may change due to quality assurance activities. The AQS database is updated by state, local, and tribal organizations who own and submit the data.

Readers are cautioned not to rank order geographic areas based on AirData reports. Air pollution levels measured at a particular monitoring site are not necessarily representative of the air quality for an entire county or urban area.

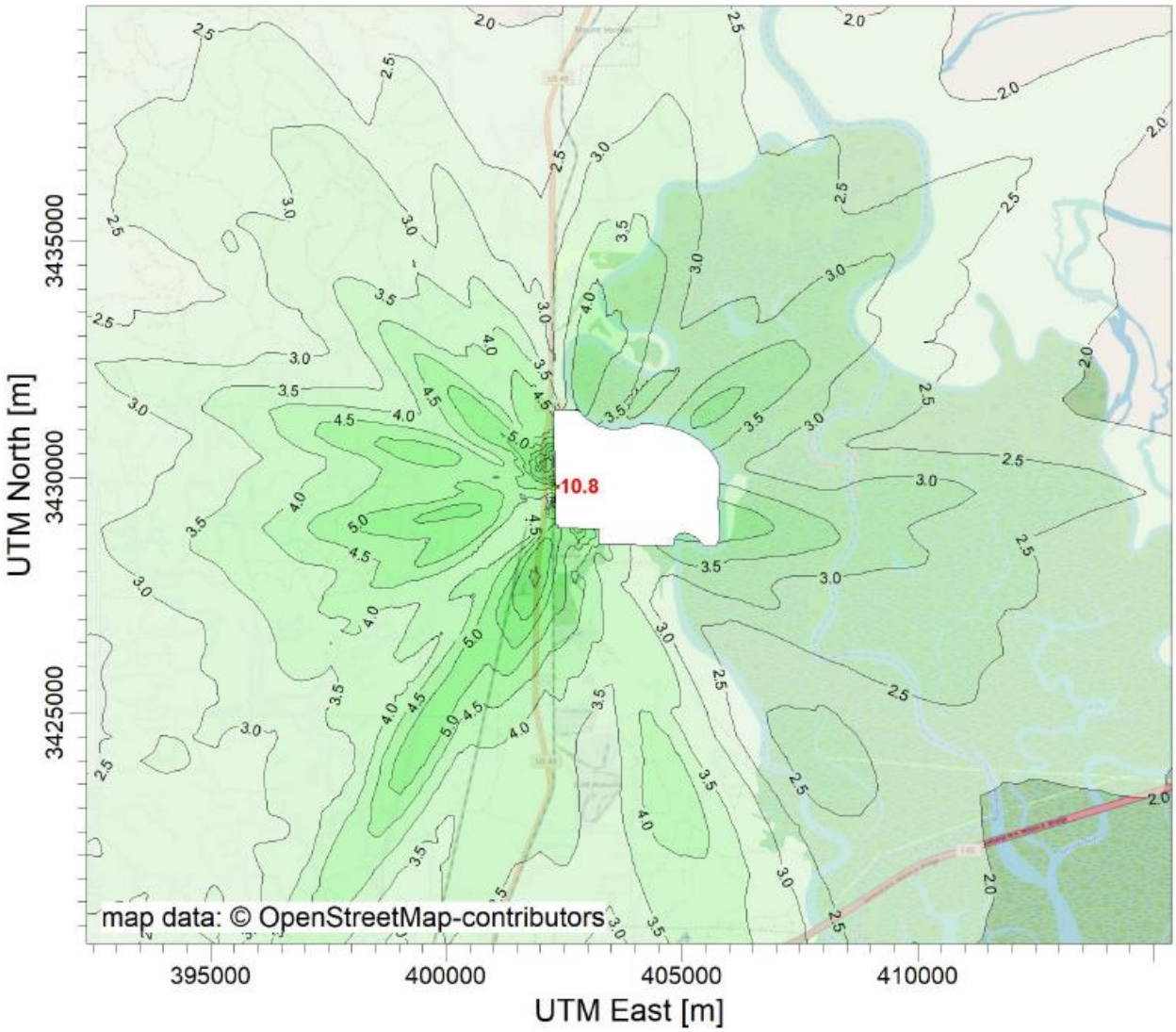
This report is based on monitor-level summary statistics. Air quality standards for some pollutants (PM2.5 and Pb) allow for combining data from multiple monitors into a site-level summary statistic that can be compared to the standard. In those cases, the site-level statistics may differ from the monitor-level statistics upon which this report is based.

Source: U.S. EPA AirData <https://www.epa.gov/air-data>
Generated: November 25, 2019

Appendix K

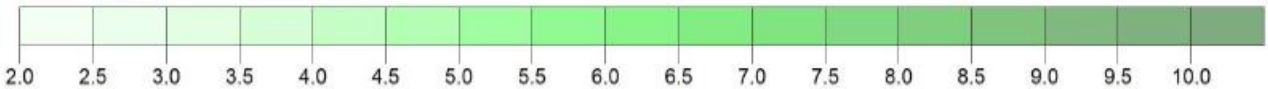
Concentration Isopleths

SIL Model Run – 1 hour NO_2 (AP Land Use)

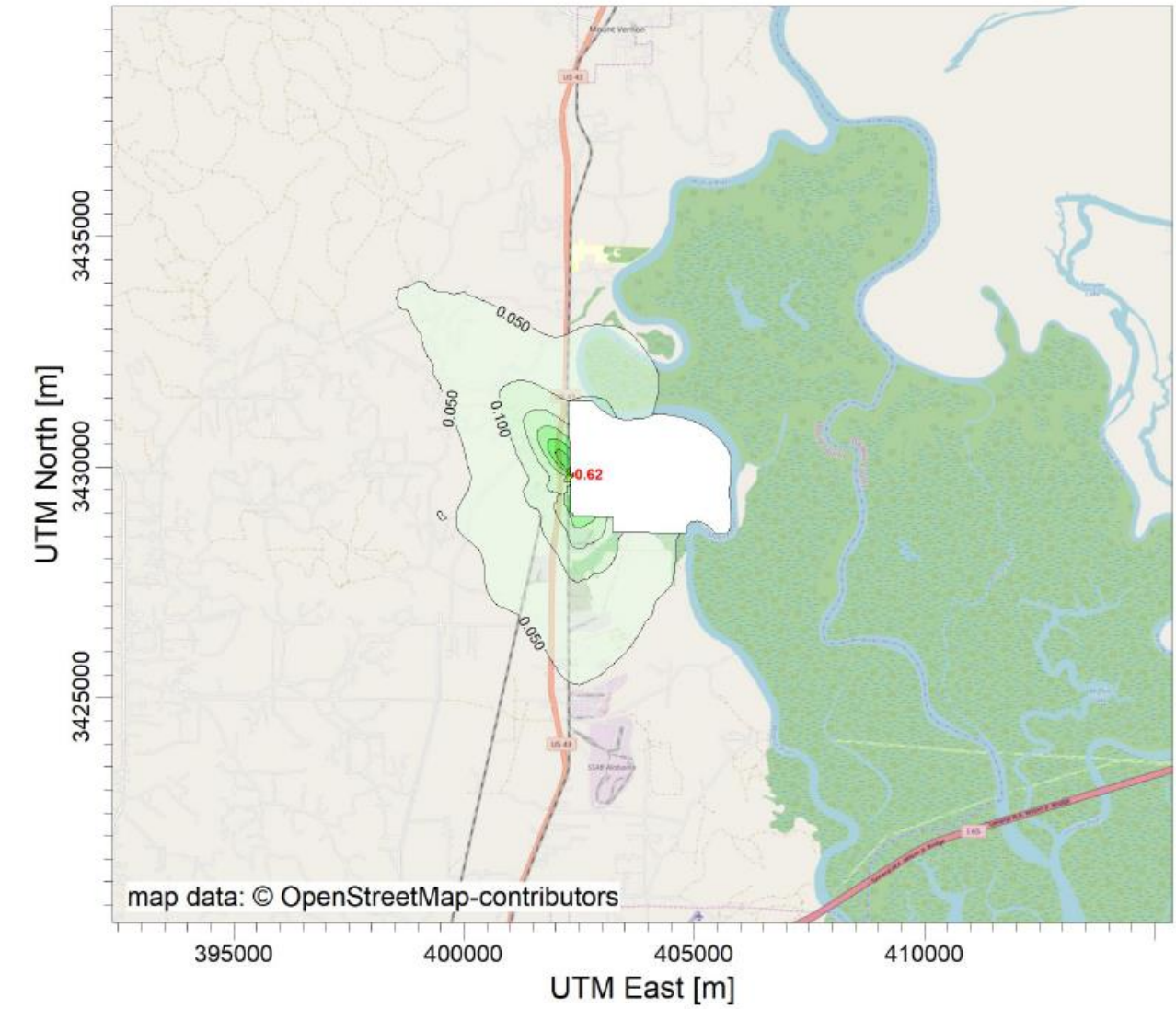


PLOT FILE OF 1ST-HIGHEST MAX DAILY 1-HR VALUES AVERAGED OVER 5 YEARS FOR SOURCE GROUP: ALL ug/m^3

Max: 10.8 [ug/m^3] at (402387.06, 3429813.08)

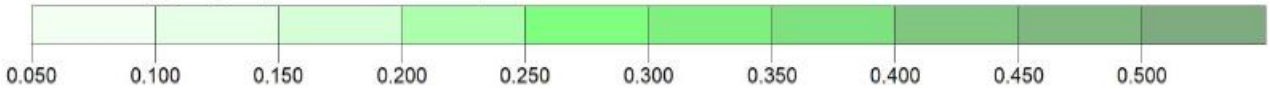


SIL Model Run – Annual NO_2 (AP Land Use)

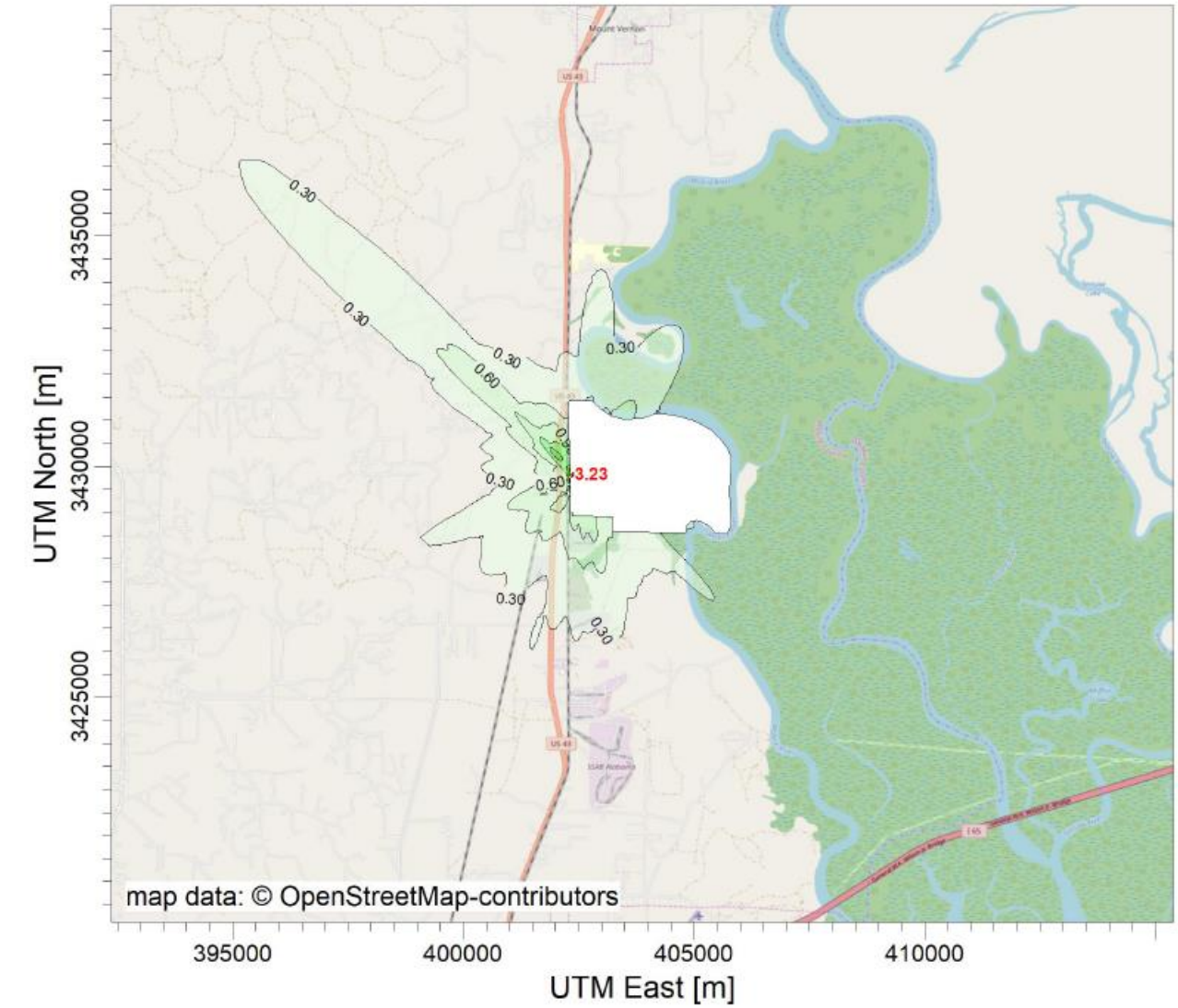


PLOT FILE OF ANNUAL VALUES AVERAGED ACROSS 1 YEARS FOR SOURCE GROUP: ALL ug/m^3

Max: 0.625 [ug/m^3] at (402386.42, 3429835.17)



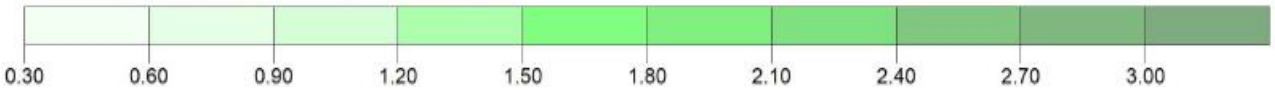
SIL Model Run – 24 hour PM_{10} (AP Land Use)



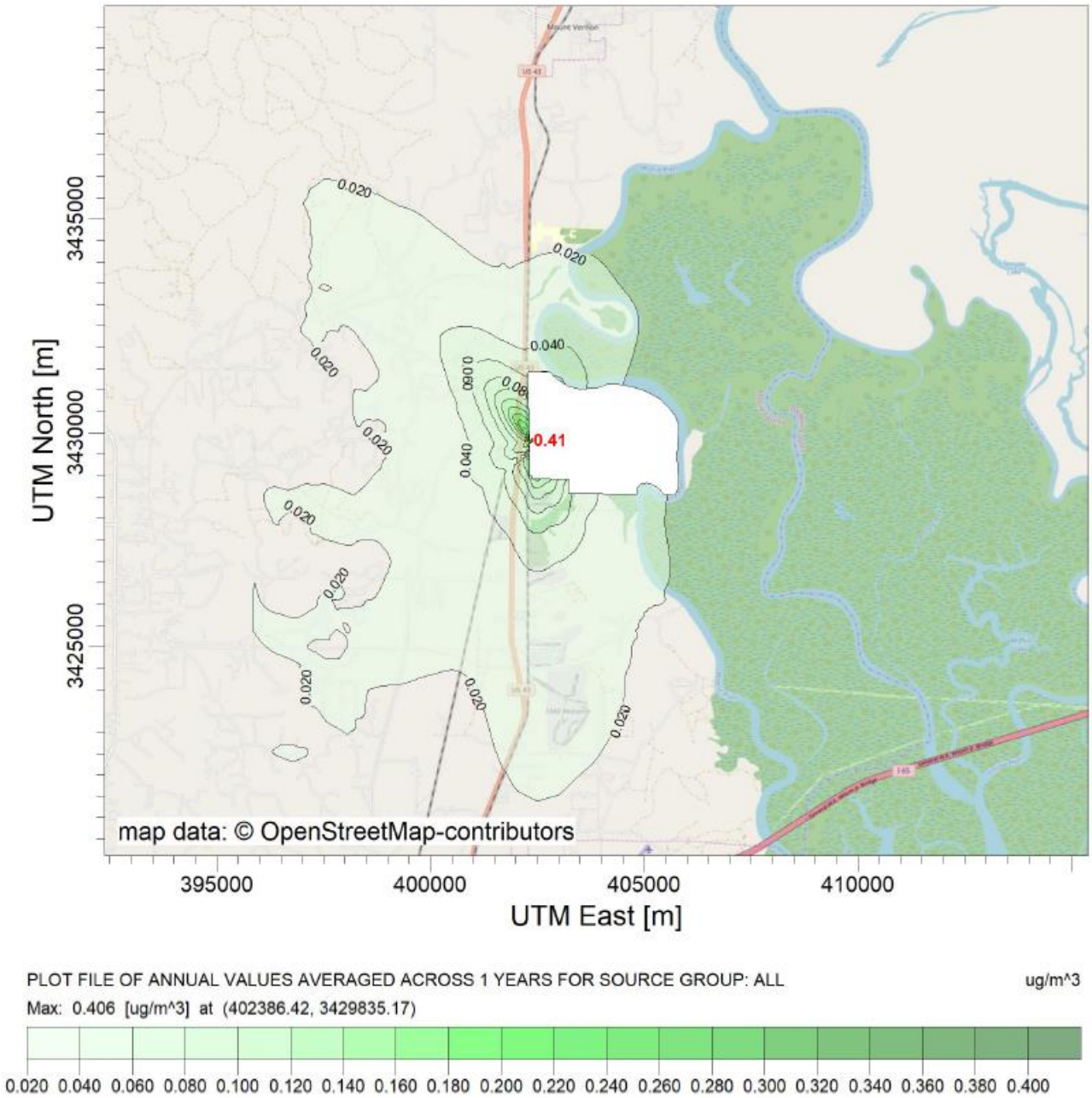
PLOT FILE OF HIGH 1ST HIGH 24-HR VALUES FOR SOURCE GROUP: ALL

ug/m^3

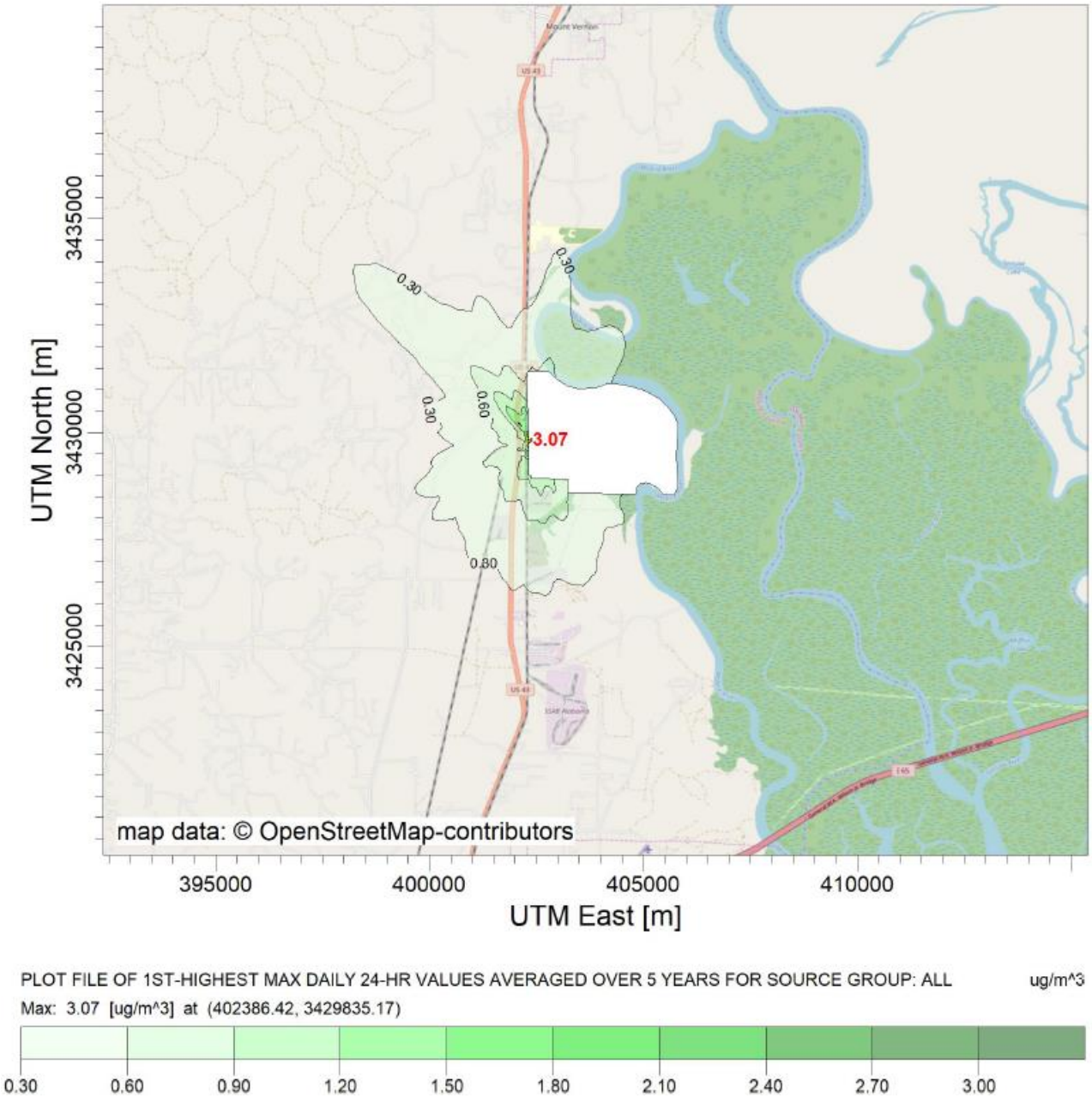
Max: 3.23 [ug/m^3] at (402386.42, 3429835.17)



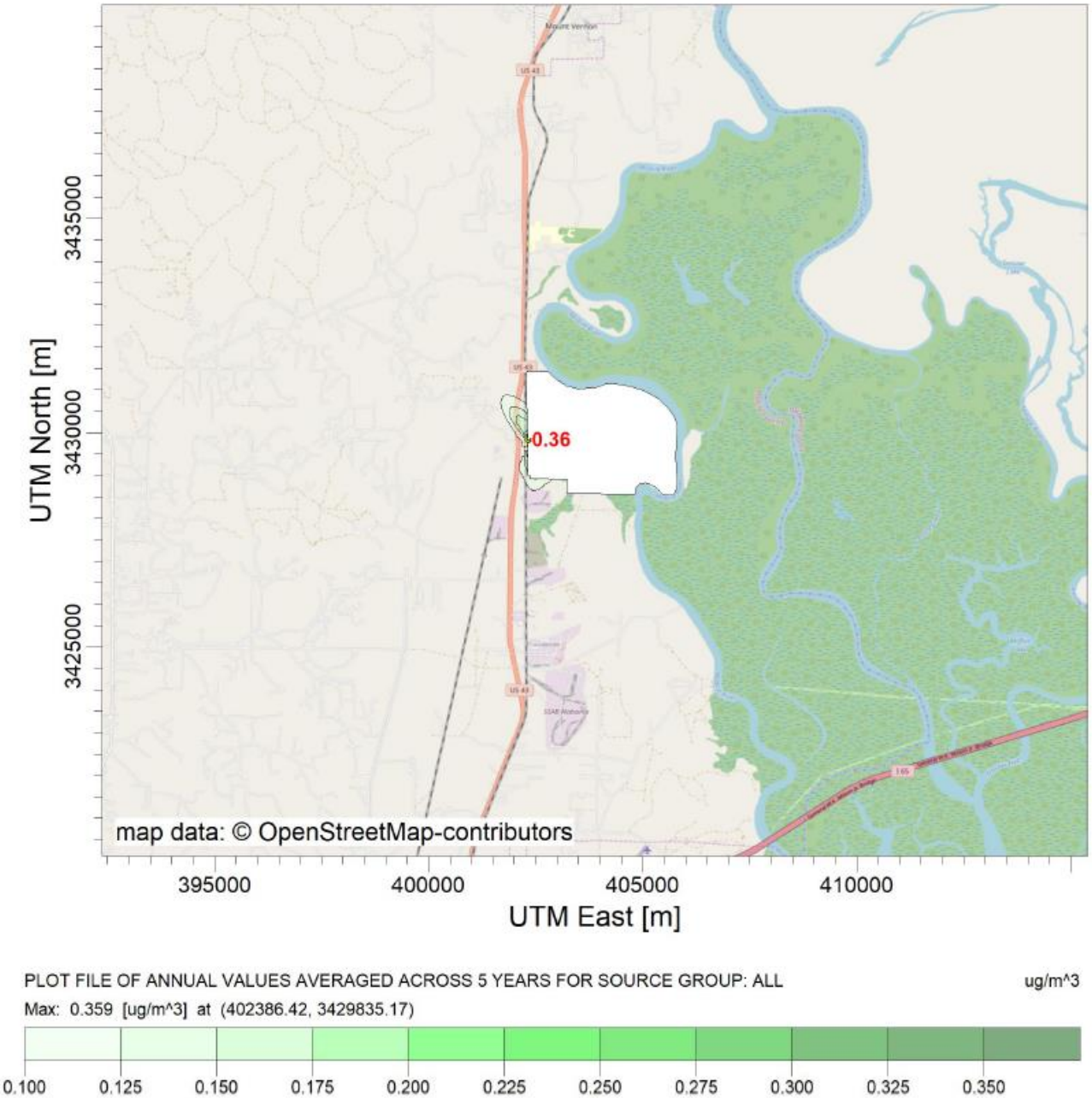
SIL Model Run – Annual PM_{10} (AP Land Use)



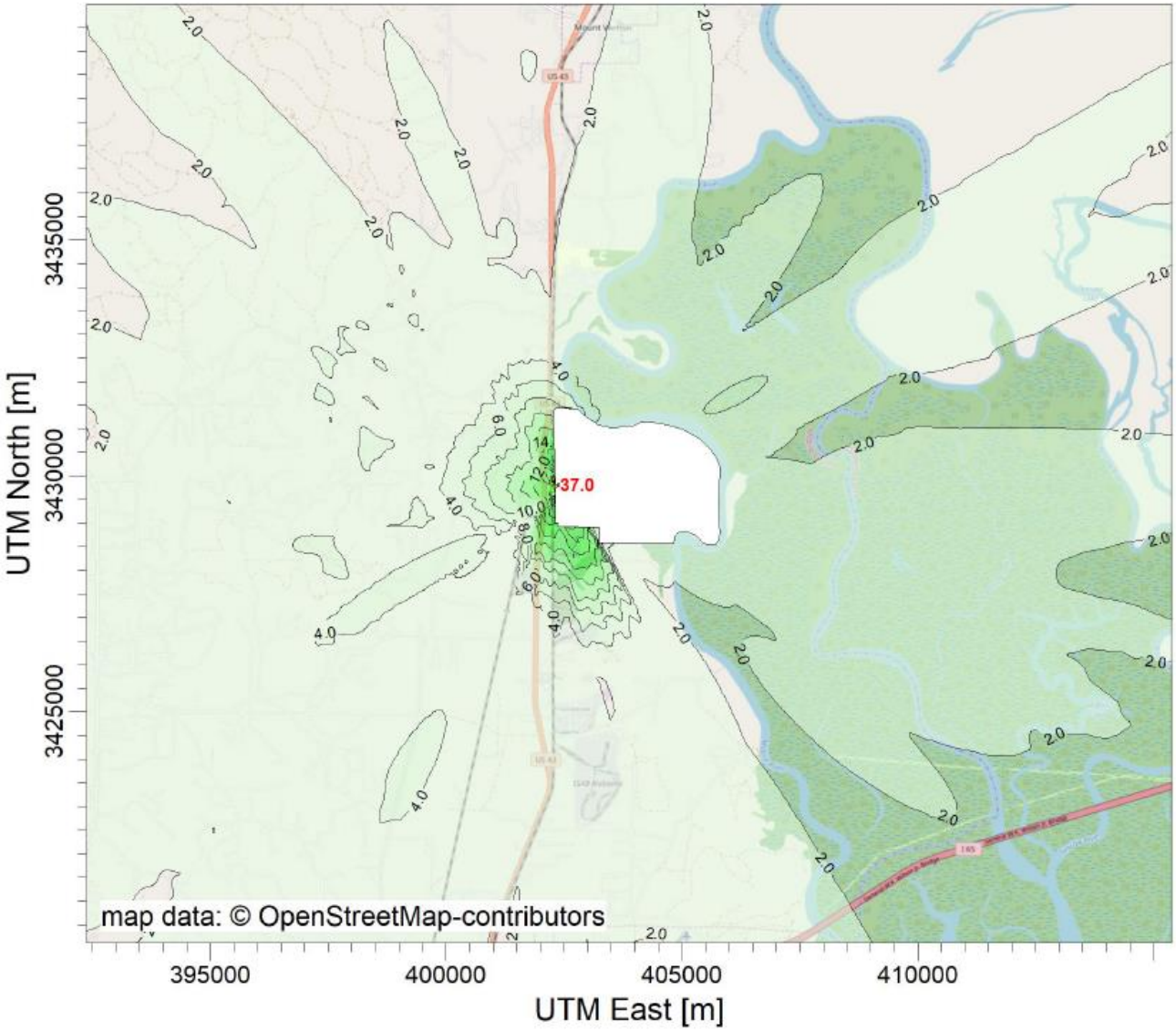
SIL Model Run – 24 hour $PM_{2.5}$ (AP Land Use)



SIL Model Run – Annual $PM_{2.5}$ (AP Land Use)



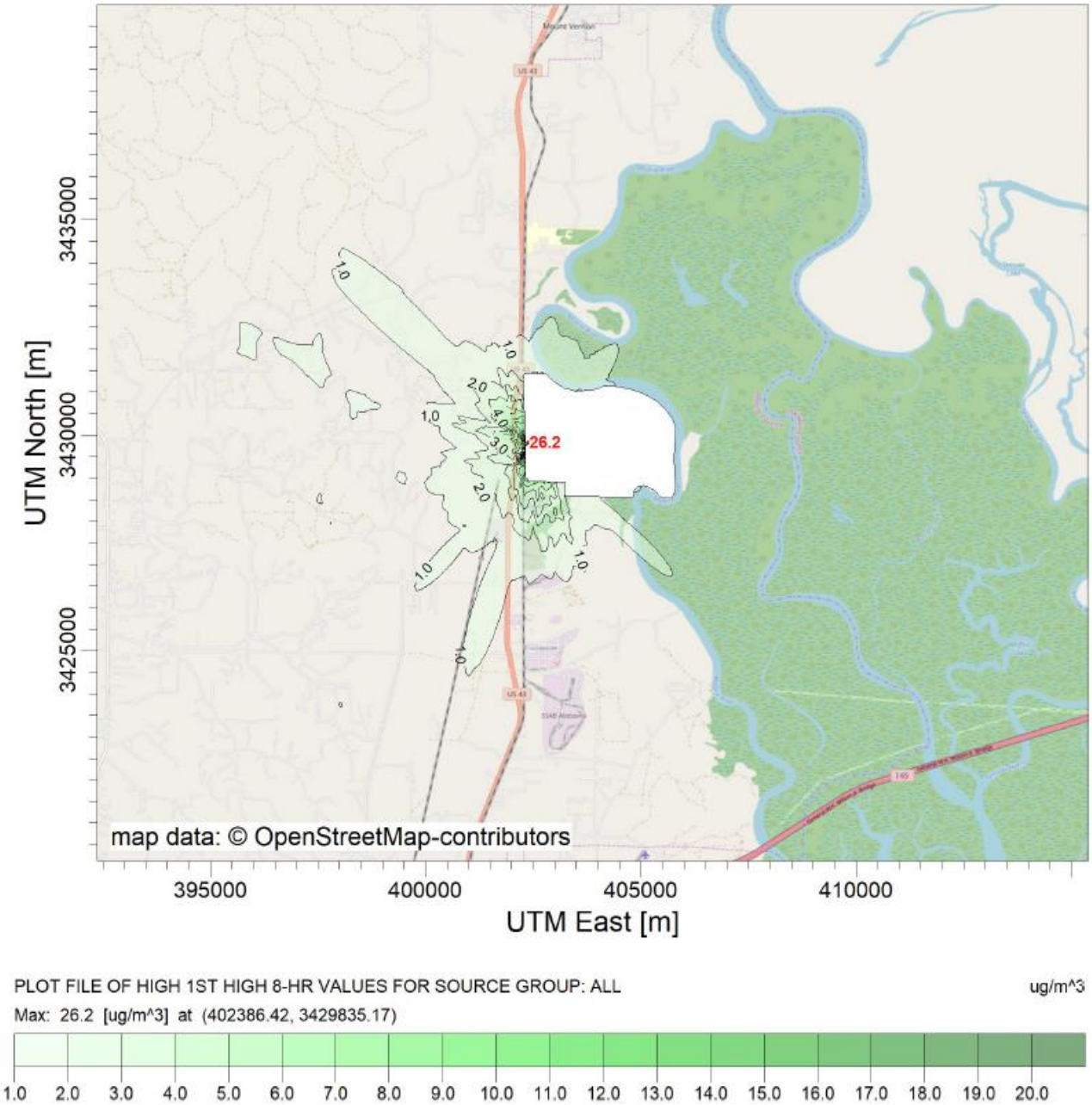
SIL Model Run – 1 hour CO (AP Land Use)



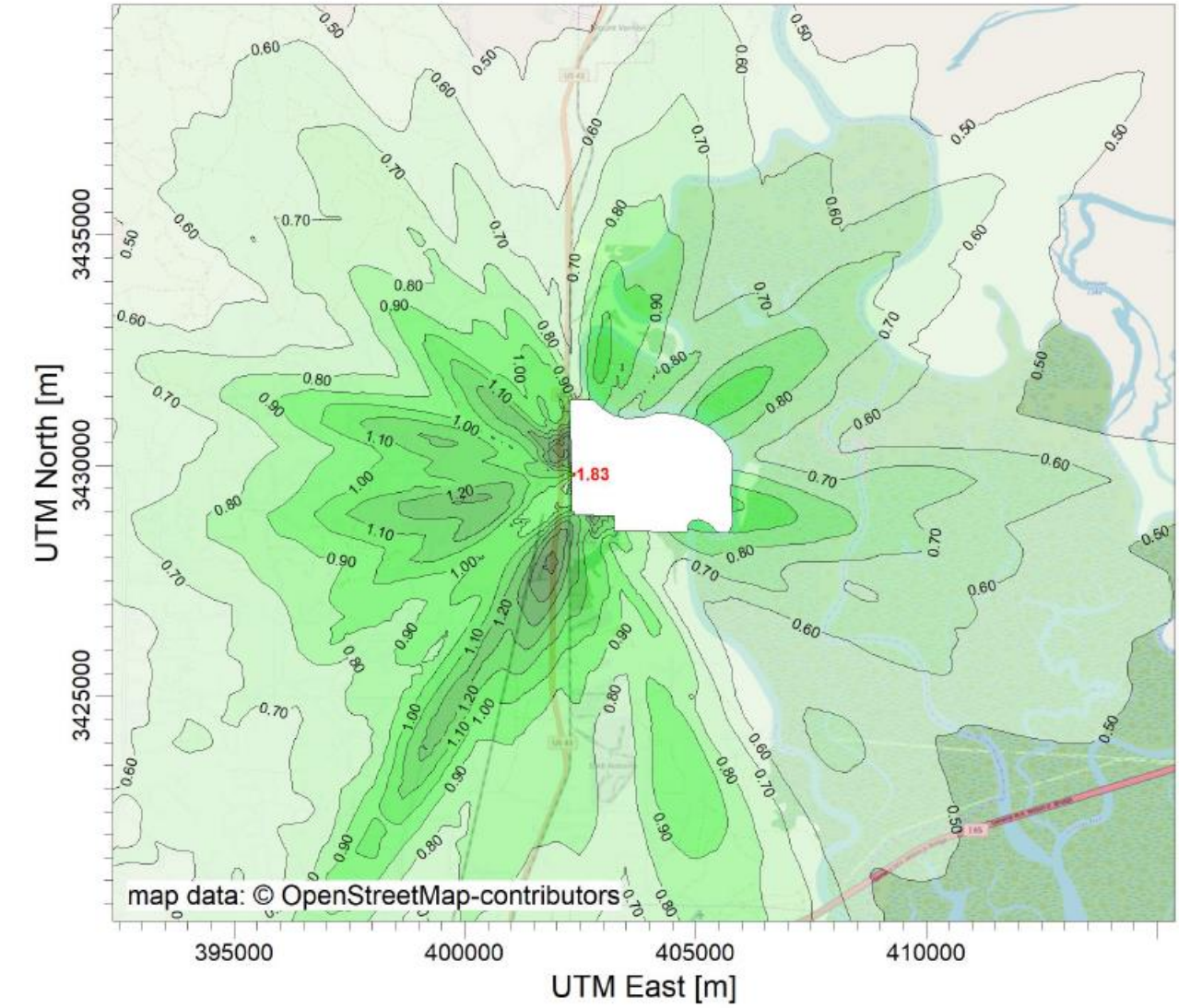
PLOT FILE OF HIGH 1ST HIGH 1-HR VALUES FOR SOURCE GROUP: ALL ug/m^3

Max: 37.0 [ug/m^3] at (402387.06, 3429813.08)

SIL Model Run – 8 hour CO (AP Land Use)



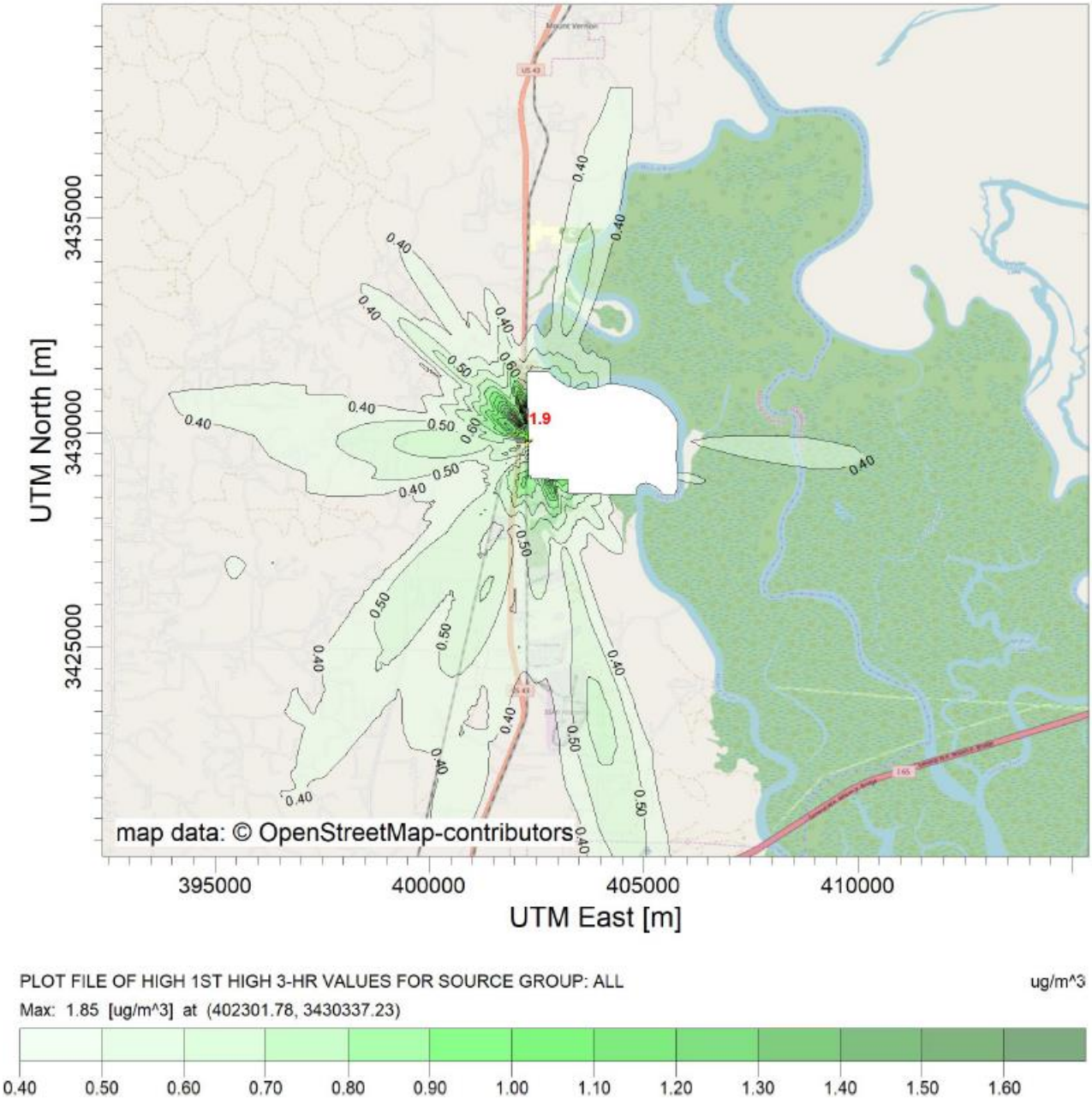
SIL Model Run – 1 hour SO_2 (AP Land Use)



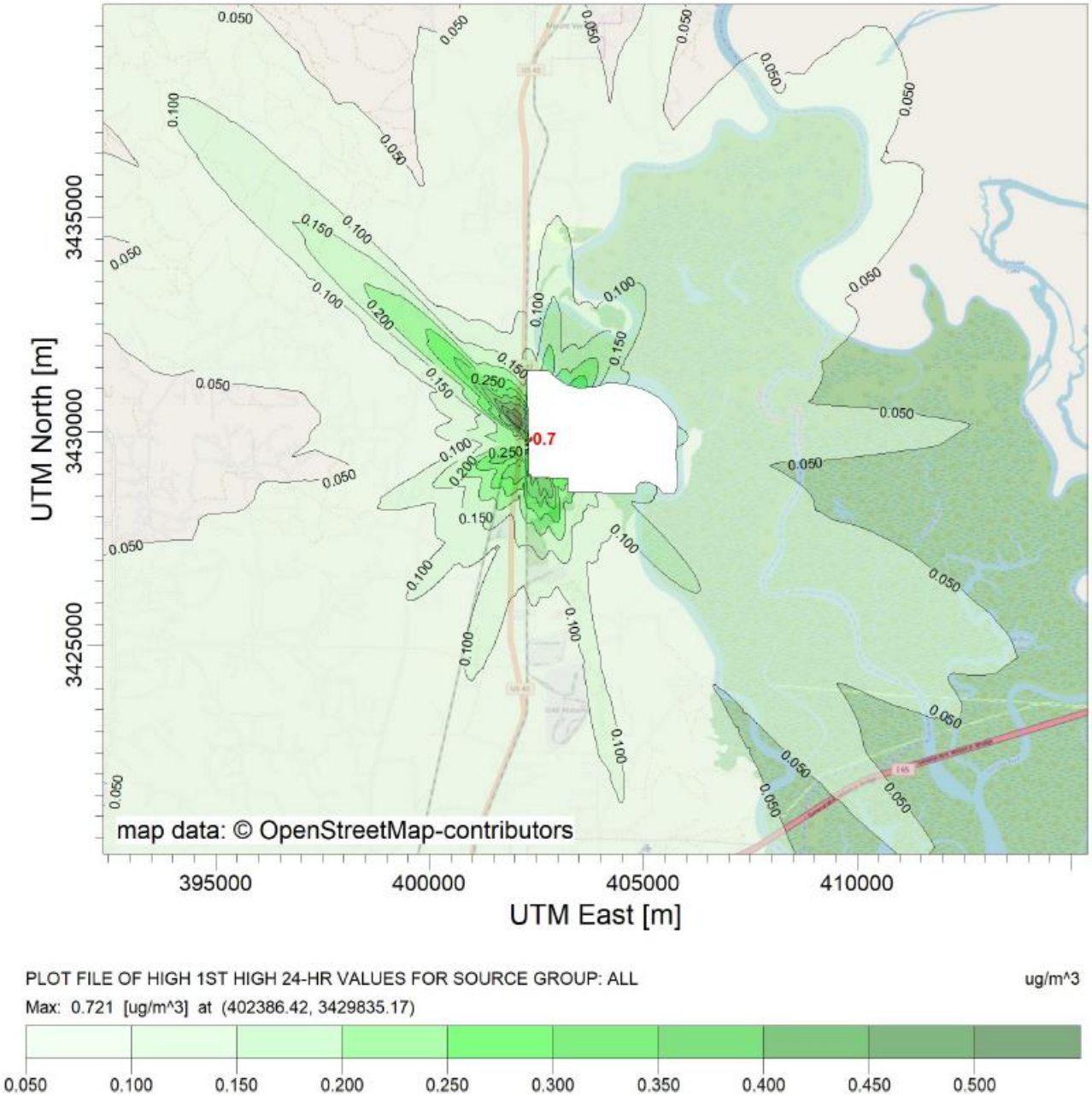
PLOT FILE OF 1ST-HIGHEST MAX DAILY 1-HR VALUES AVERAGED OVER 5 YEARS FOR SOURCE GROUP: ALL ug/m^3

Max: 1.83 [ug/m^3] at (402387.06, 3429813.08)

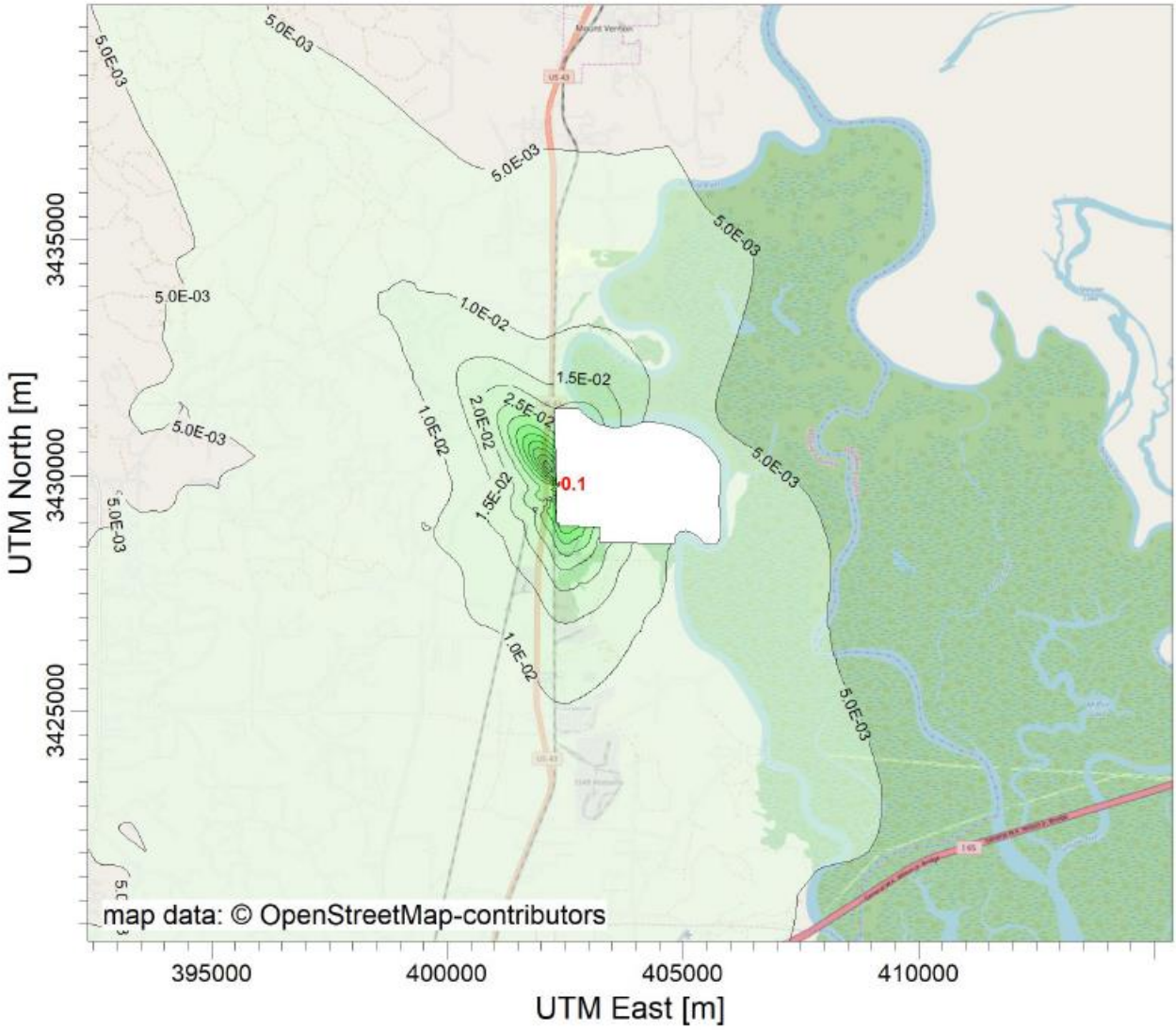
SIL Model Run – 3 hour SO_2 (AP Land Use)



SIL Model Run – 24 hour SO_2 (AP Land Use)



SIL Model Run – Annual SO_2 (AP Land Use)

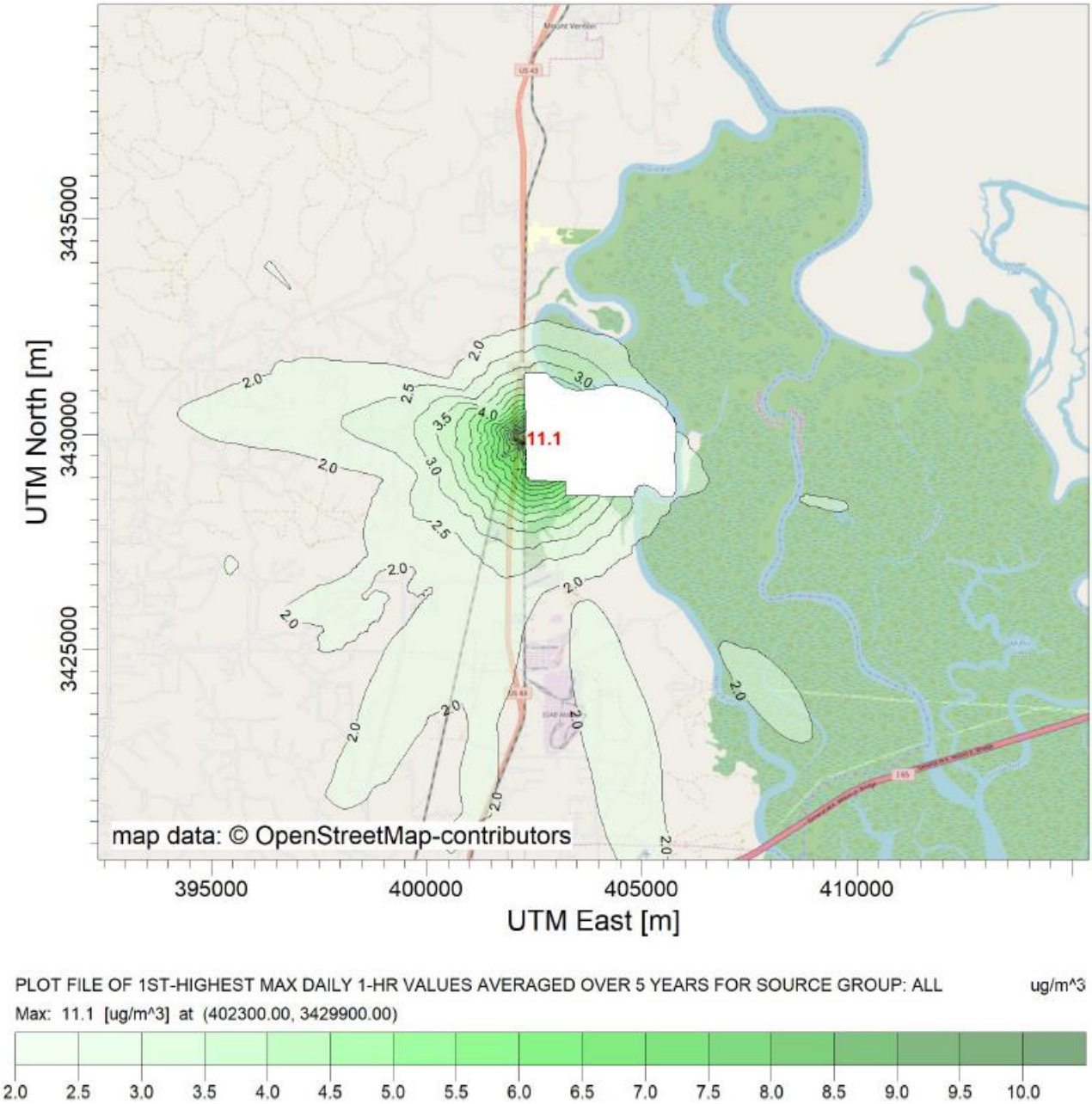


PLOT FILE OF ANNUAL VALUES AVERAGED ACROSS 1 YEARS FOR SOURCE GROUP: ALL ug/m^3

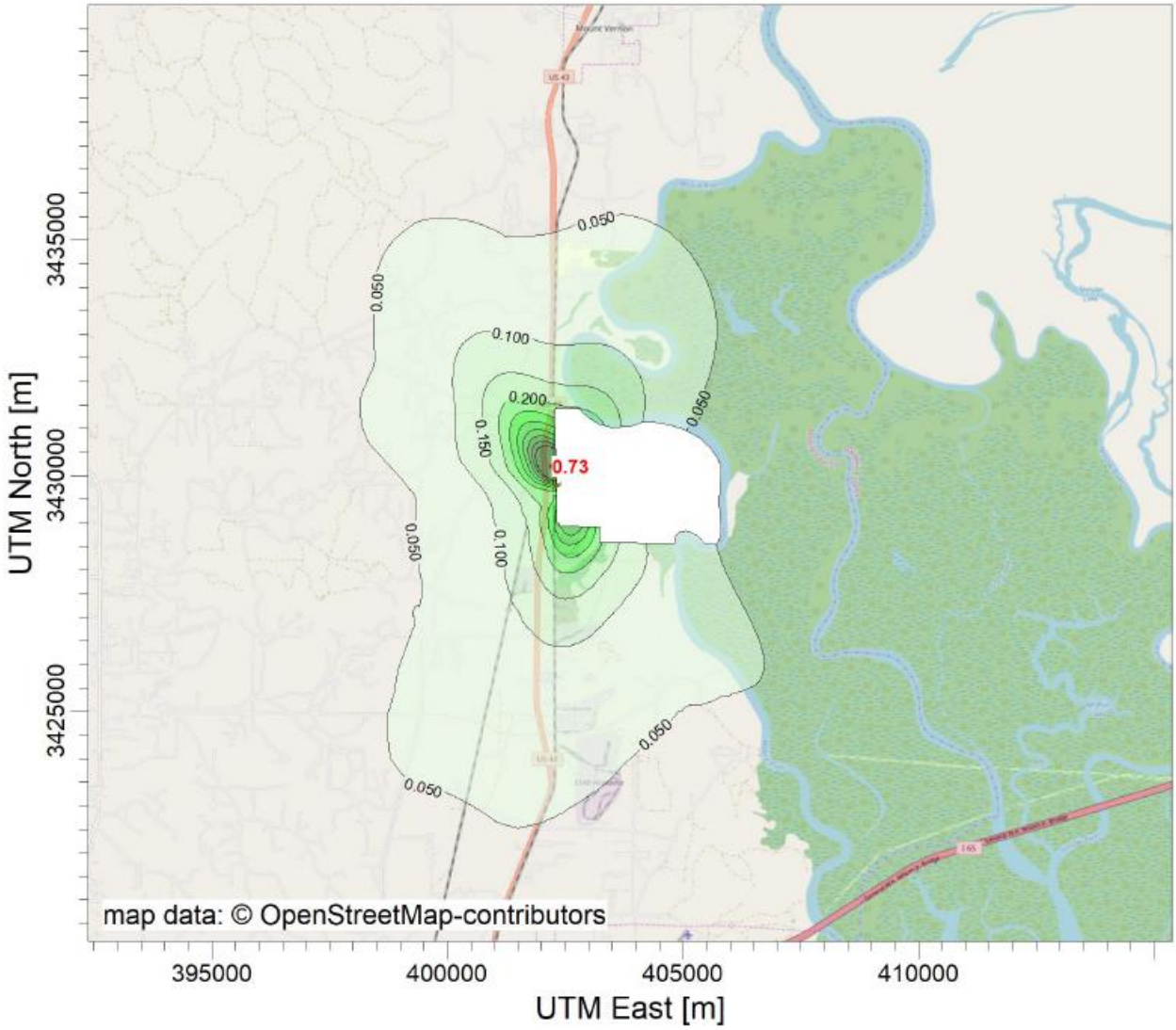
Max: 9.5E-02 [ug/m^3] at (402386.42, 3429835.17)

5.0E-03 1.0E-02 1.5E-02 2.0E-02 2.5E-02 3.0E-02 3.5E-02 4.0E-02 4.5E-02 5.0E-02 5.5E-02 6.0E-02 6.5E-02 7.0E-02 7.5E-02 8.0E-02

SIL Model Run – 1 hour NO_2 (SITE Land Use)

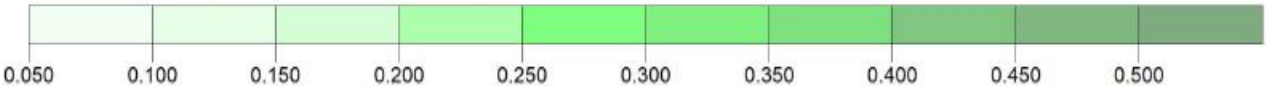


SIL Model Run – Annual NO_2 (SITE Land Use)

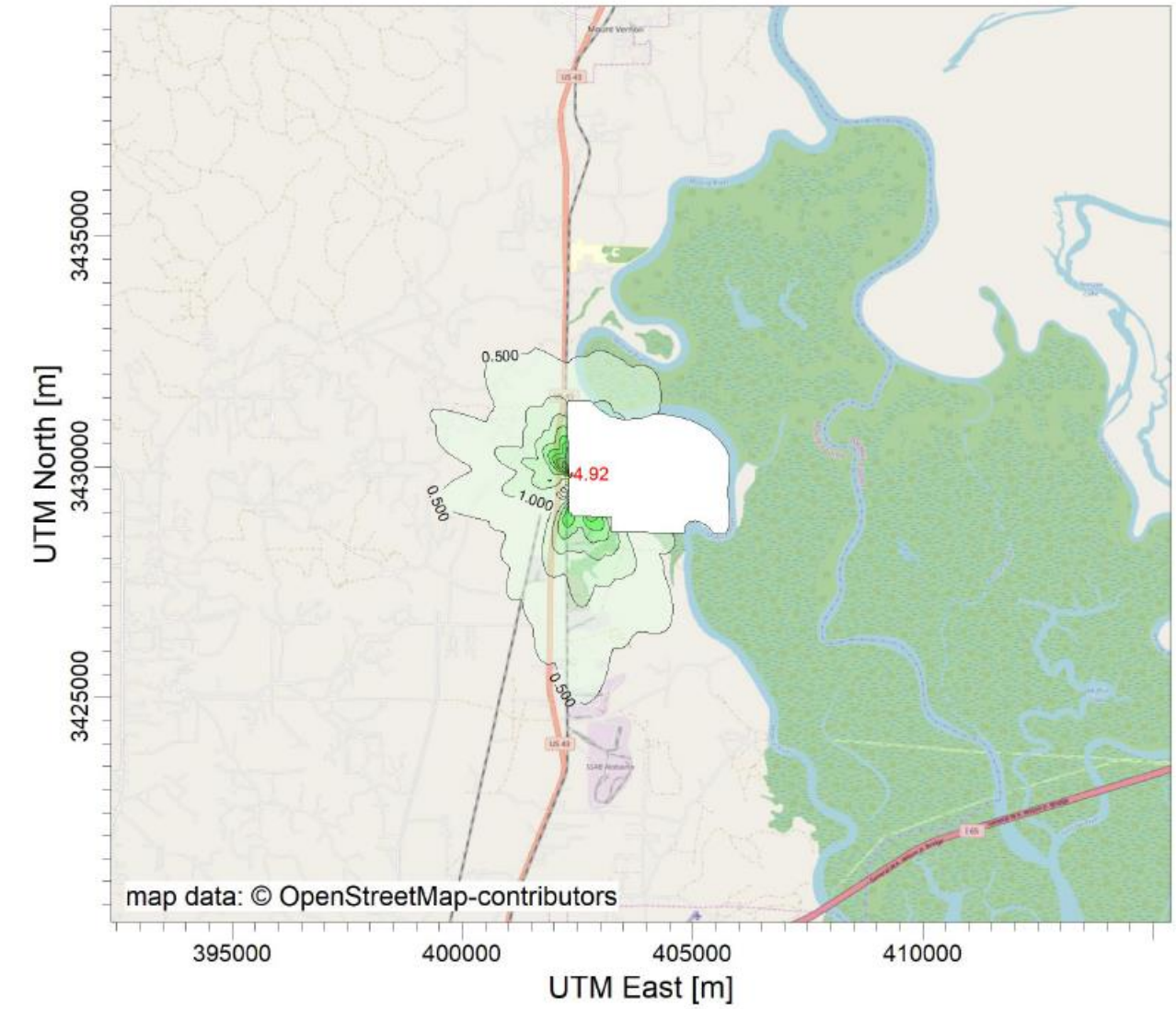


PLOT FILE OF ANNUAL VALUES AVERAGED ACROSS 1 YEARS FOR SOURCE GROUP: ALL ug/m^3

Max: 0.725 [ug/m^3] at (402200.00, 3430200.00)



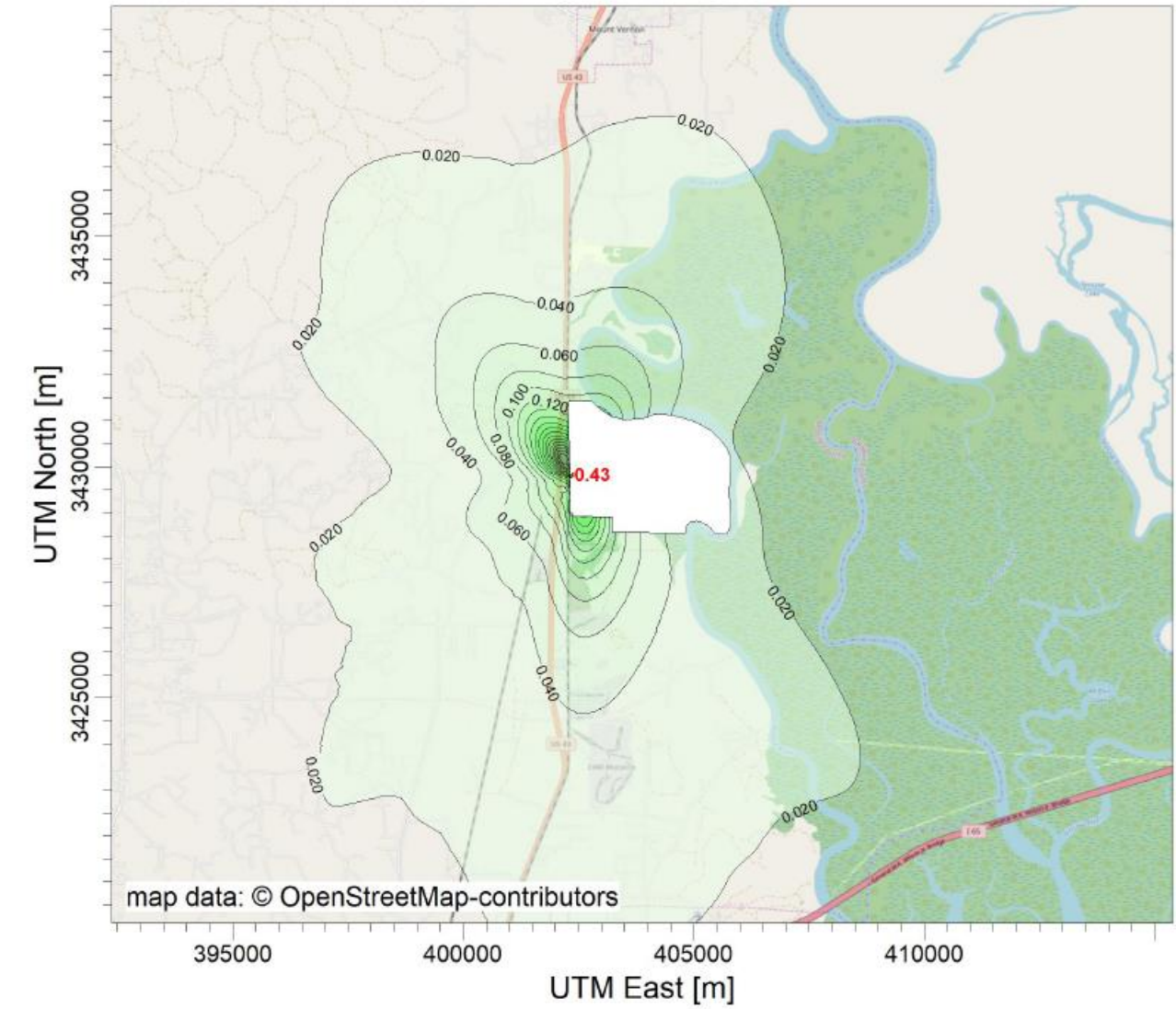
SIL Model Run – 24 hour PM_{10} (SITE Land Use)



PLOT FILE OF HIGH 1ST HIGH 24-HR VALUES FOR SOURCE GROUP: ALL ug/m^3

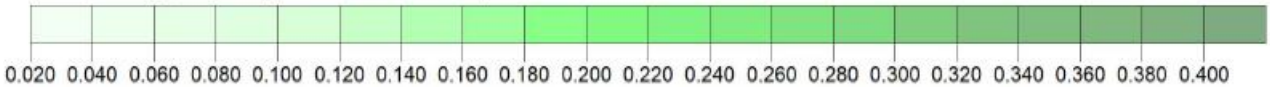
Max: 4.916 [ug/m^3] at (402386.42, 3429835.17)

SIL Model Run – Annual PM_{10} (SITE Land Use)

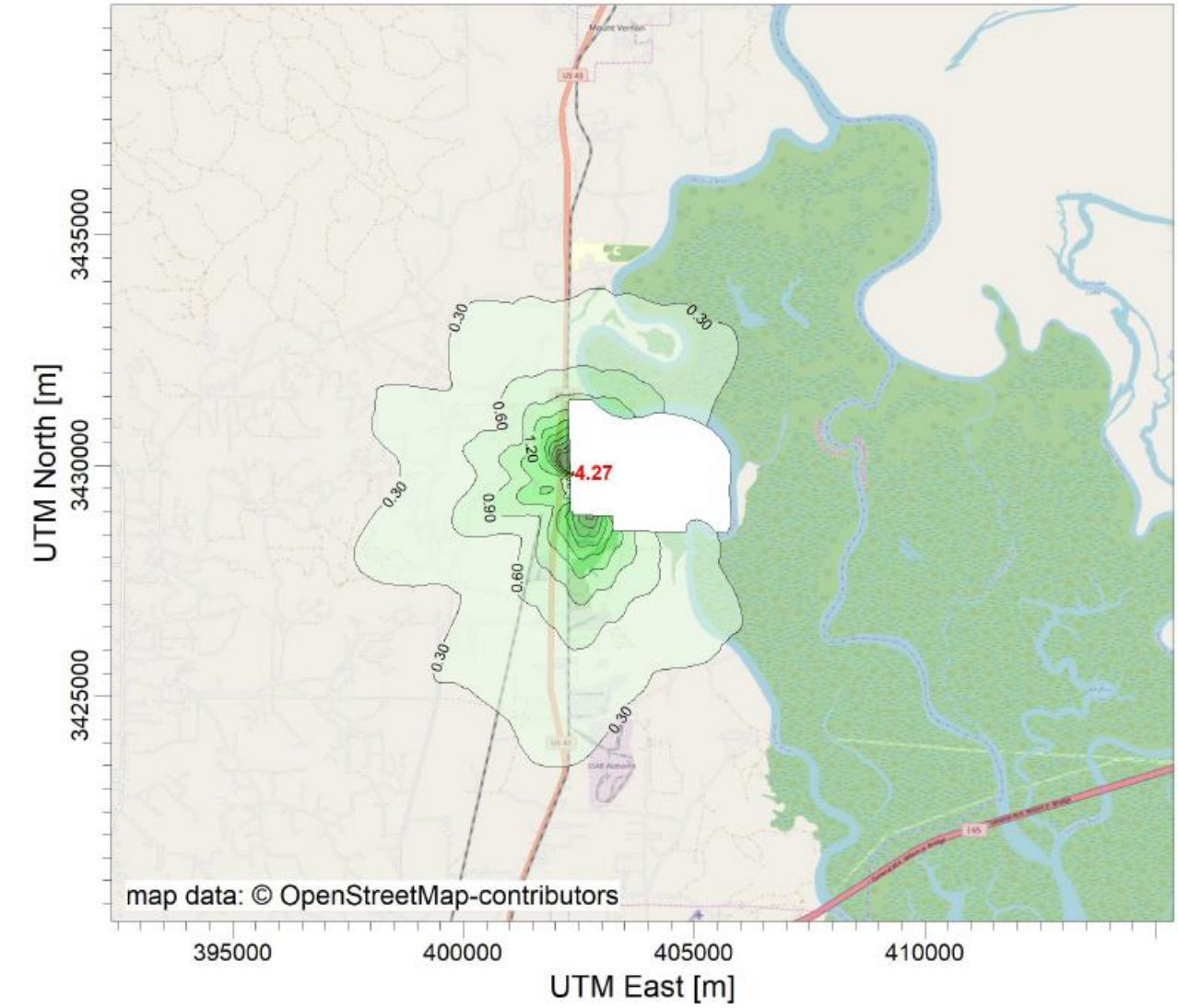


PLOT FILE OF ANNUAL VALUES AVERAGED ACROSS 1 YEARS FOR SOURCE GROUP: ALL ug/m^3

Max: 0.429 [ug/m^3] at (402386.42, 3429835.17)



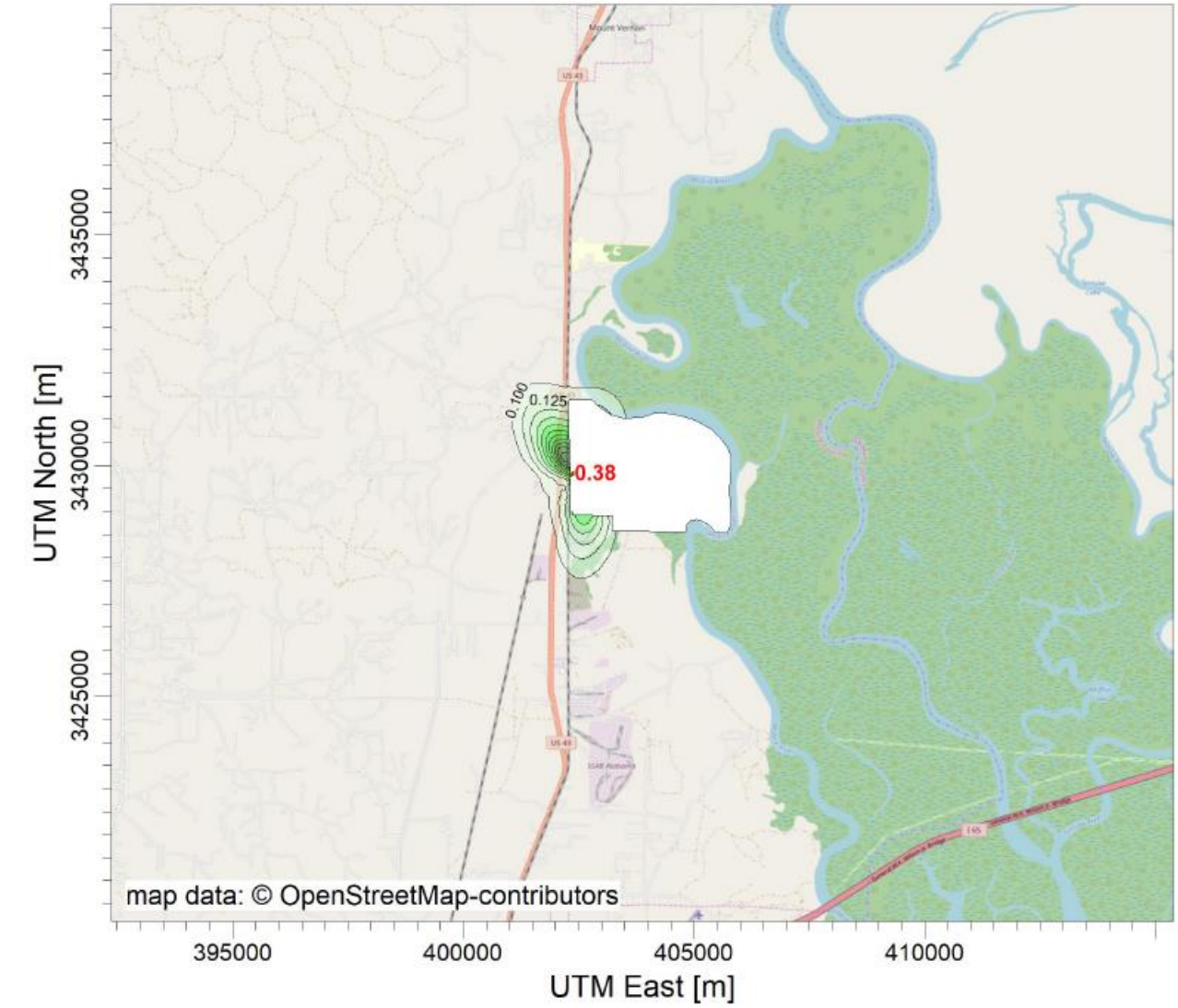
SIL Model Run – 24 hour $PM_{2.5}$ (SITE Land Use)



PLOT FILE OF 1ST-HIGHEST MAX DAILY 24-HR VALUES AVERAGED OVER 5 YEARS FOR SOURCE GROUP: ALL ug/m^3

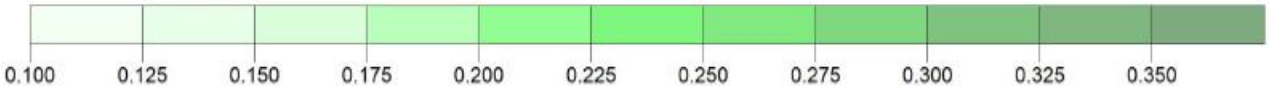
Max: 4.27 [ug/m^3] at (402386.42, 3429835.17)

SIL Model Run – Annual $PM_{2.5}$ (SITE Land Use)

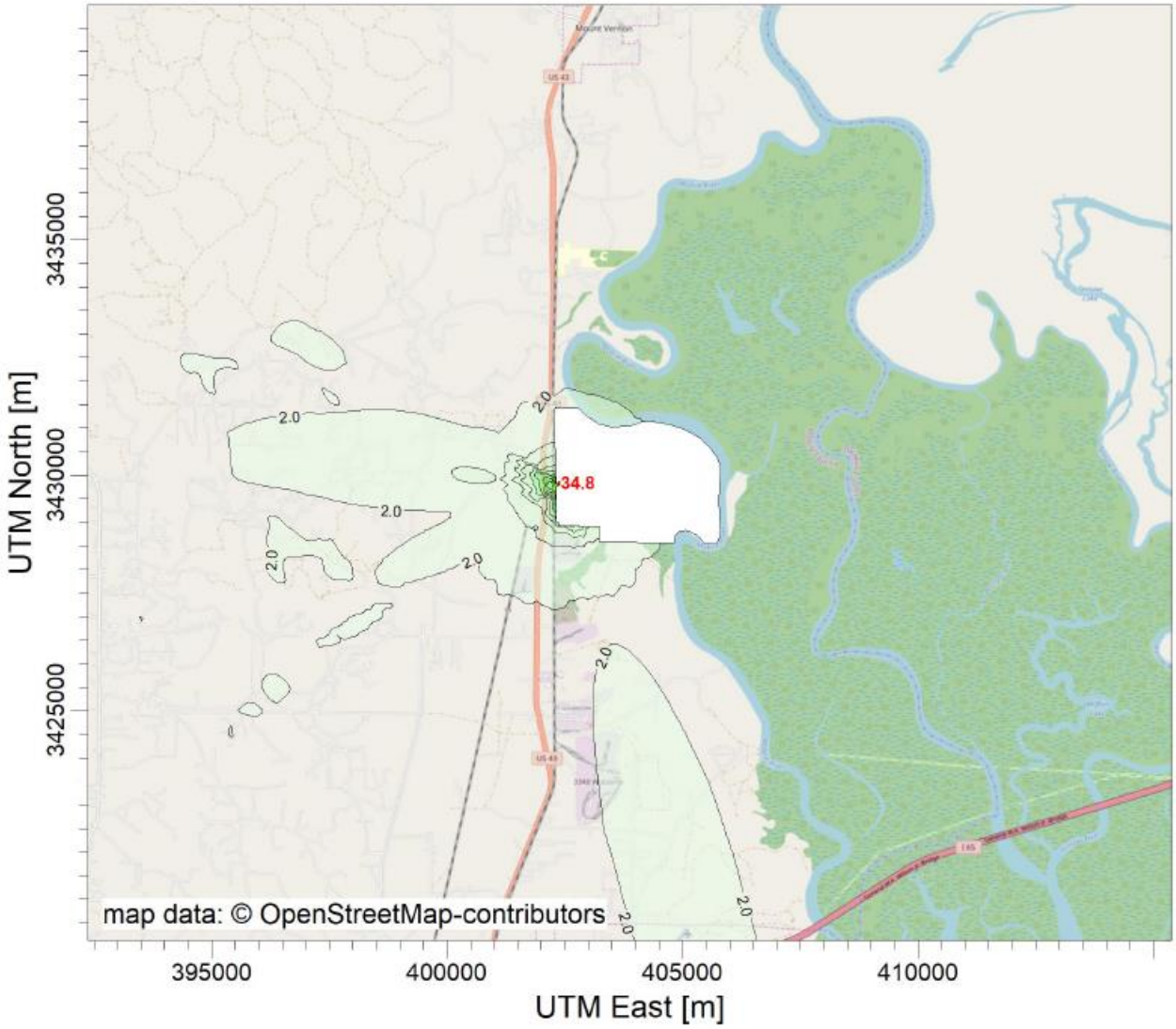


PLOT FILE OF ANNUAL VALUES AVERAGED ACROSS 5 YEARS FOR SOURCE GROUP: ALL ug/m^3

Max: 0.384 [ug/m^3] at (402386.42, 3429835.17)



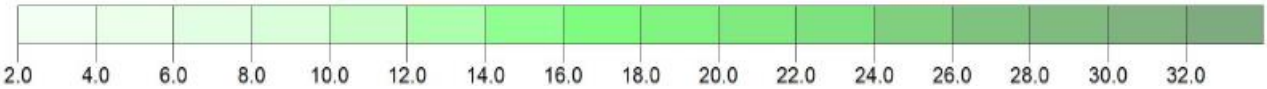
SIL Model Run – 1 hour CO (SITE Land Use)



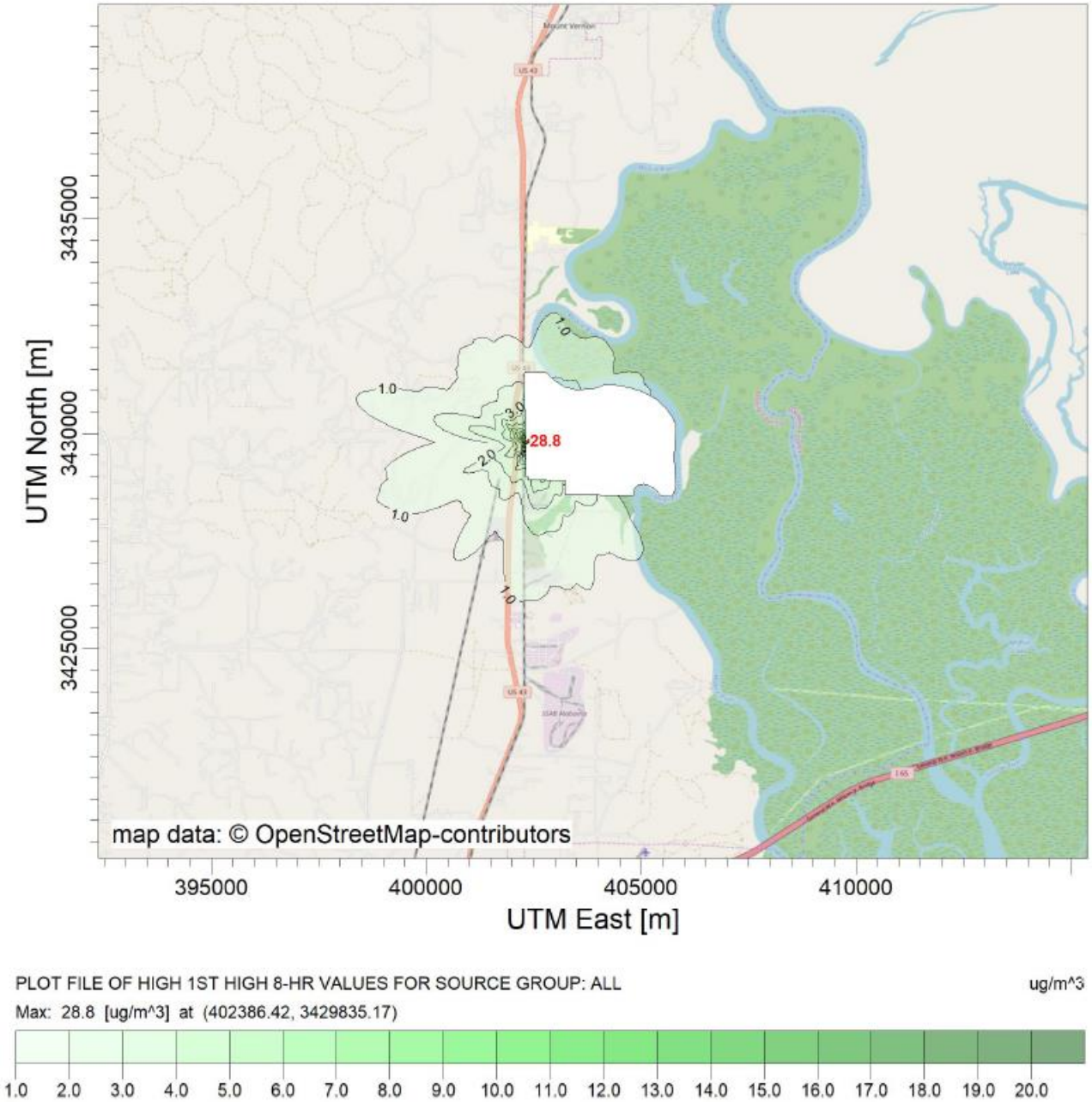
PLOT FILE OF HIGH 1ST HIGH 1-HR VALUES FOR SOURCE GROUP: ALL

ug/m^3

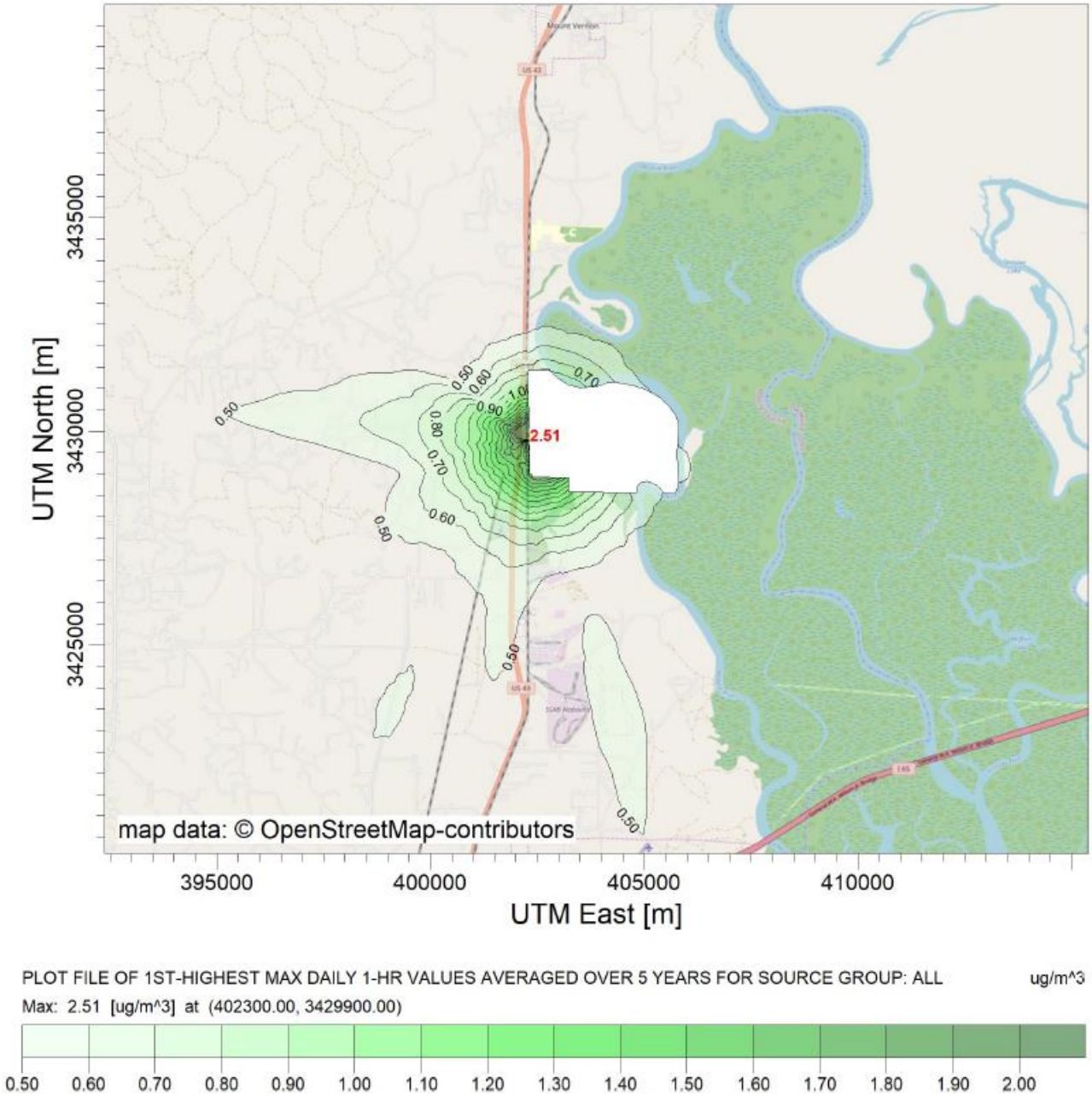
Max: 34.8 [ug/m^3] at (402386.42, 3429835.17)



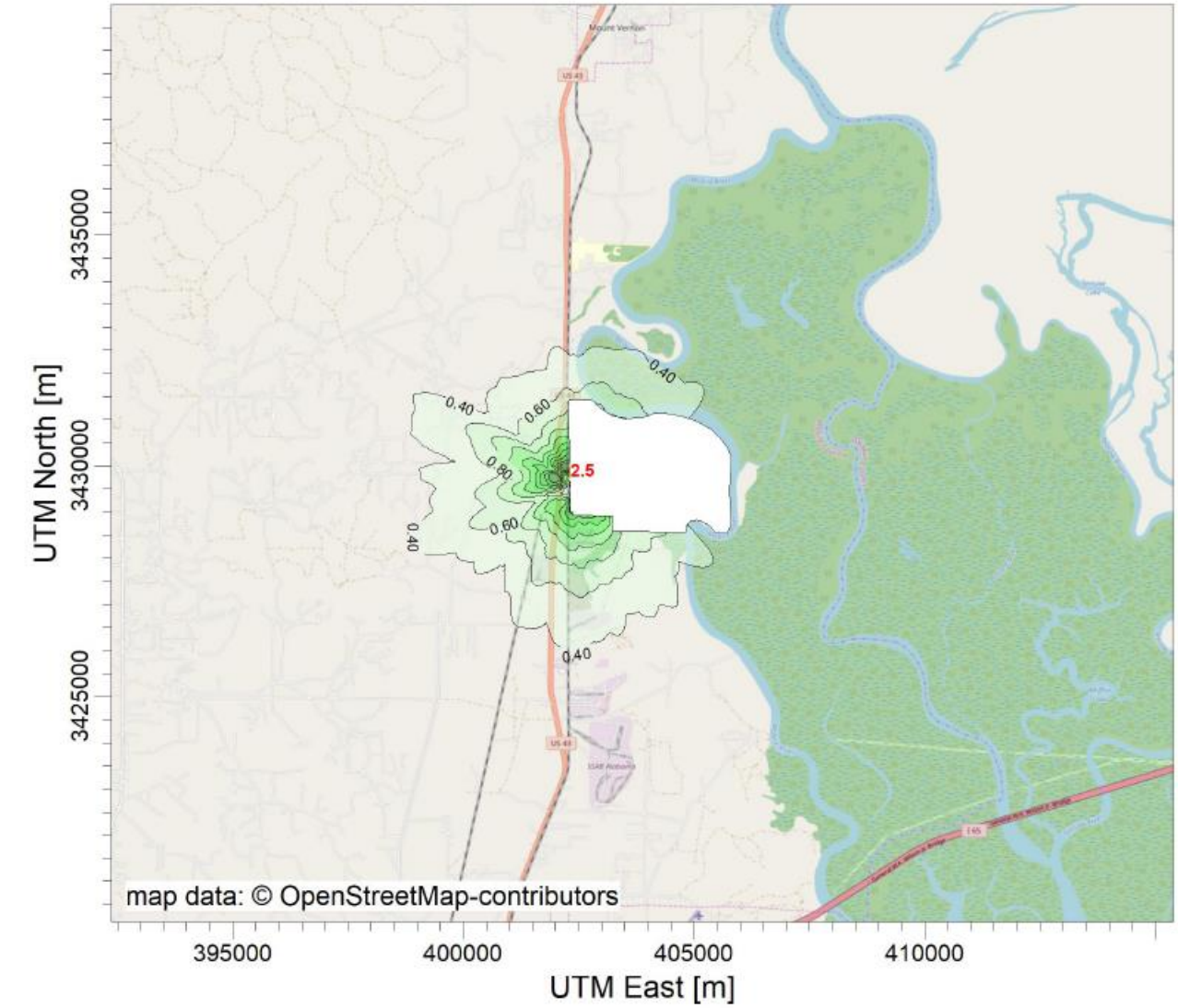
SIL Model Run – 8 hour CO (SITE Land Use)



SIL Model Run – 1 hour SO_2 (SITE Land Use)



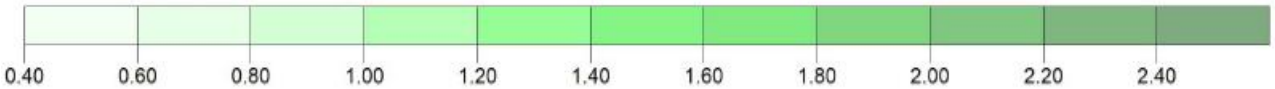
SIL Model Run – 3 hour SO_2 (SITE Land Use)



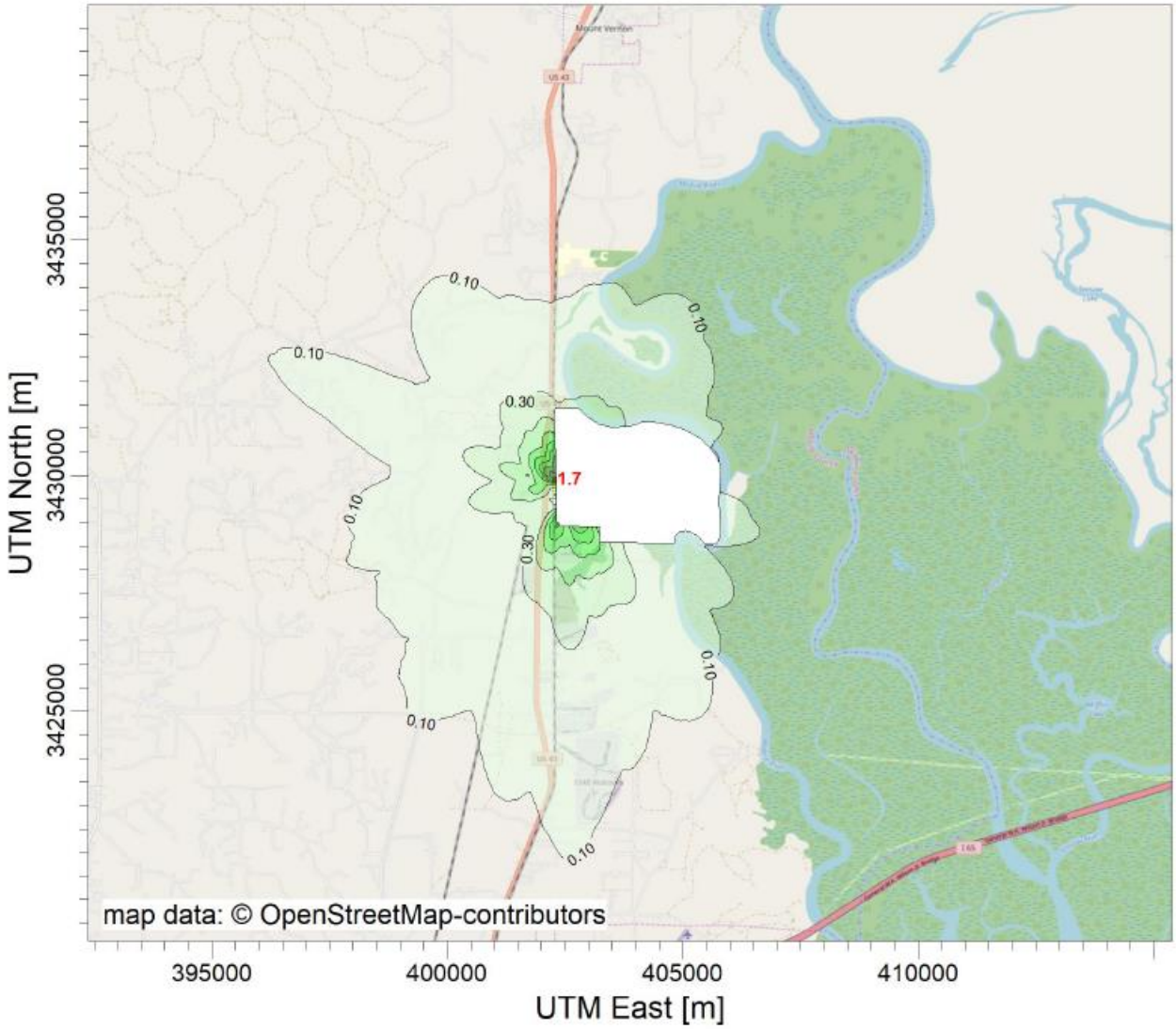
PLOT FILE OF HIGH 1ST HIGH 3-HR VALUES FOR SOURCE GROUP: ALL

ug/m^3

Max: 2.45 [ug/m^3] at (402300.00, 3429900.00)

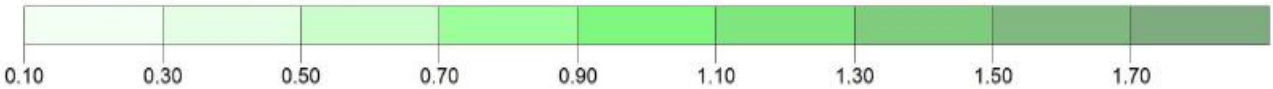


SIL Model Run – 24 hour SO_2 (SITE Land Use)

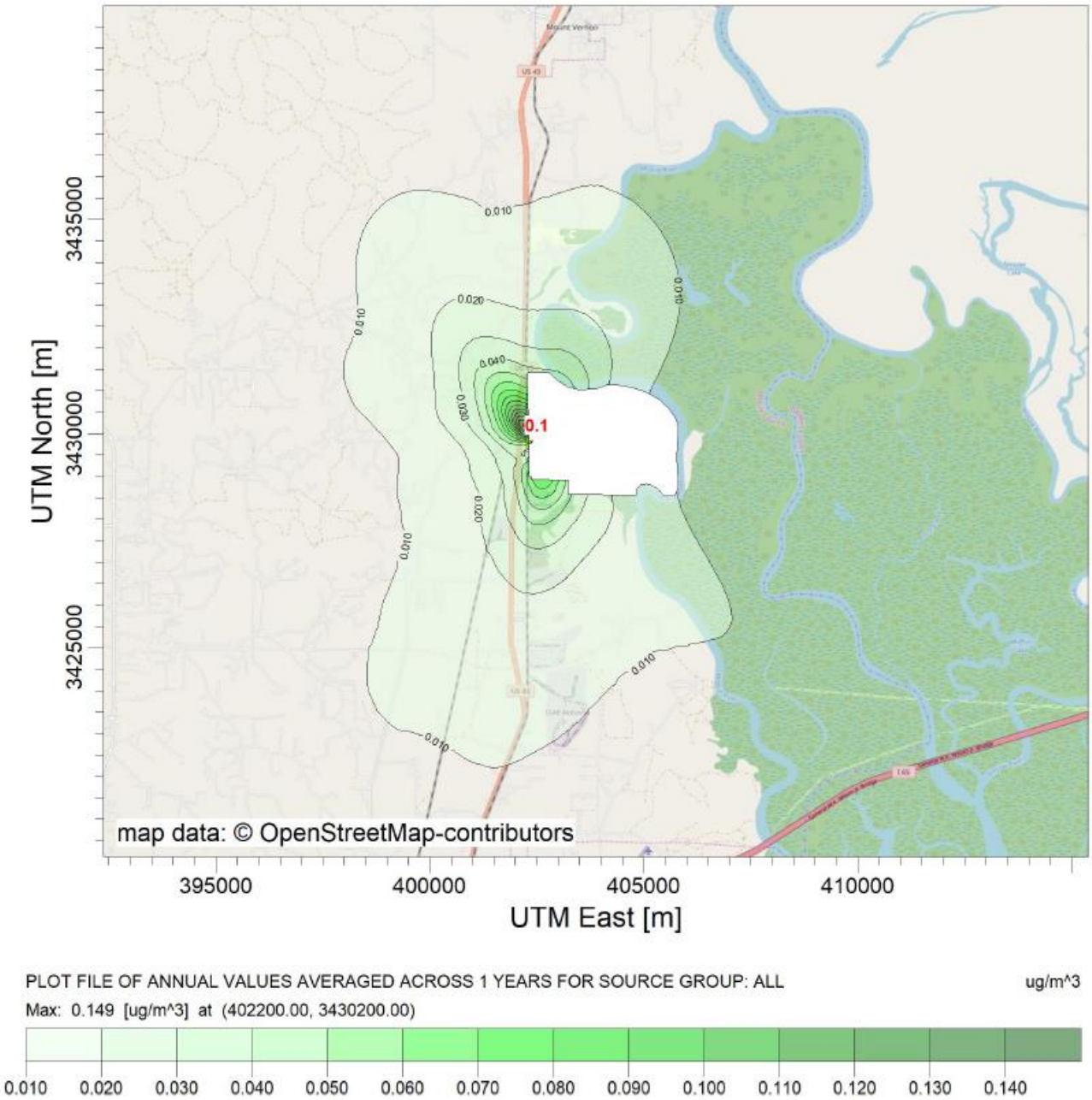


PLOT FILE OF HIGH 1ST HIGH 24-HR VALUES FOR SOURCE GROUP: ALL ug/m^3

Max: 1.71 [ug/m^3] at (402311.09, 3429939.59)



SIL Model Run – Annual SO_2 (SITE Land Use)



Phillips, Tyler

From: Phillips, Tyler
Sent: Tuesday, June 23, 2020 10:51 AM
To: Howard, Nikia
Subject: RE: Unit 8 and 9 Monitoring

I'd like for you to propose an averaging period, and I should be able to get the drafts to you this week. I just need to go through them one more time.

Tyler

From: Howard, Nikia <NHoward@southernco.com>
Sent: Tuesday, June 23, 2020 9:25 AM
To: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Subject: RE: Unit 8 and 9 Monitoring

Tyler,

I wanted to follow back up with you regarding the minimum temperature value for CAM. We would like to use 625°F as the minimum value. Did you have an averaging period in mind or do we need to propose one? Also, do you know when you will be able to share a draft of the permit? I know the T5s and CD permits are a top priority, but just wanted to know if the Barry permit was next in line.

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

Alabama Power

From: Howard, Nikia <NHoward@southernco.com>
Sent: Thursday, May 14, 2020 2:43 PM
To: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Subject: Re: Unit 8 and 9 Monitoring

Right now we are considering a minimum temperature.

Get Outlook for iOS

From: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Sent: Thursday, May 14, 2020 2:19:41 PM
To: Howard, Nikia <NHoward@southernco.com>
Subject: RE: Unit 8 and 9 Monitoring

EXTERNAL MAIL: Caution Opening Links or Files

I was hoping to have the monitoring set prior to submitting the drafts to review internally, but I could go ahead and add just the parameter for now and fill in the value later. After the internal review and revisions I can send you the drafts to look over. Would the value be a temp range or a min temp?

Tyler

From: Howard, Nikia <NHoward@southernco.com>
Sent: Thursday, May 14, 2020 1:58 PM
To: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Subject: RE: Unit 8 and 9 Monitoring

Tyler,

I just wanted to give you an update on the CAM parameter. We are considering the catalyst inlet temperature for a parameter, but are still evaluating a value for this. Will you need this information before you are able to share a draft of the permit?

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

Alabama Power

From: Howard, Nikia
Sent: Tuesday, May 05, 2020 7:29 AM
To: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Subject: RE: Unit 8 and 9 Monitoring

Tyler,

Yes, I agree that CAM would be applicable. I will get back with you when we decide on a parameter and value.

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212

Mobile 205.259.0655
nhoward@southernco.com

Alabama Power

From: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Sent: Monday, May 04, 2020 9:54 AM
To: Howard, Nikia <NHoward@southernco.com>
Subject: Unit 8 and 9 Monitoring

EXTERNAL MAIL: Caution Opening Links or Files

Nikia,

From what I can tell it looks like units and 8 and 9 could be subject to CAM for CO/VOC when the units are incorporated into the Title V later due to the BACT limits and Oxidation Catalyst. If so, we will need to add some CAM-like monitoring for CO/VOC to the air permit. Let me know if you agree CAM would be applicable, and if you agree, what are your thoughts on an Oxidation Catalyst parameter and value we could use for monitoring? This would not need to look like a CAM plan submittal, just a parameter and value that would satisfy CAM.

Give me a call if you want to discuss or have any questions.

Regard,

TYLER PHILLIPS
Environmental Engineering Specialist, Senior
Industrial Minerals Section
Energy Branch, Air Division
Alabama Department of Environmental Management
tyler.phillips@adem.alabama.gov
(334) 271-7867

Phillips, Tyler

From: Howard, Nikia <NHoward@southernco.com>
Sent: Friday, July 31, 2020 1:07 PM
To: Phillips, Tyler
Cc: Steele, C. Mark
Subject: RE: Barry U8&9 Draft Permits
Attachments: X014 (07-20)_APC Comments.docx; X015 (07-20)_APC Comments.docx; X016 (07-20)_APC Comments.docx

Tyler,

Attached are our additional comments on the revised drafts. We do not have any additional comments on the draft permit for the auxiliary boiler and cooling towers, but I included it just to be complete.
Please let us know the decision regarding the load change exemption. We would like to see the final draft if possible.

I've also included the additional information you requested regarding the control efficiencies for the SCR/DLNB on the NGCC and the ULNB for the aux boiler. If you need any additional information, please let me know.

<u>Combined Cycle Combustion Units</u>
NOx control –

a. Proposed BACT: SCR in combination with dry low NOx combustors **(80%-90%)**
b. **Water or steam injection – 60% control**
c. Good combustion practices – "base" level of emissions performance; no control efficiency

<u>Auxiliary Boiler</u>
NOx control –

a. Proposed BACT: Ultra Low NOx burners **(85%-90%)**
b. **SCR – 85-90% control** (equivalent or lower control efficiency than ULNBs)

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

Alabama Power

From: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Sent: Friday, July 17, 2020 12:43 PM
To: Howard, Nikia <NHoward@southernco.com>
Cc: Steele, C. Mark <CMSteele@southernco.com>
Subject: RE: Barry U8&9 Draft Permits

EXTERNAL MAIL: Caution Opening Links or Files

Attached are revised drafts. Please see my comment/question about the load change exception for the NGCC units.

Tyler

From: Howard, Nikia <NHoward@southernco.com>
Sent: Friday, July 10, 2020 1:10 PM
To: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Cc: Steele, C. Mark <CMSteele@southernco.com>
Subject: RE: Barry U8&9 Draft Permits

Tyler,

Please find attached our comments on the draft permits for the Barry combined cycle project. We would like to see another version after you have addressed these comments. Let me know if you have any questions.

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

Alabama Power

From: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Sent: Thursday, June 25, 2020 10:50 AM
To: Howard, Nikia <NHoward@southernco.com>; Steele, C. Mark <CMSteele@southernco.com>
Subject: Barry U8&9 Draft Permits

EXTERNAL MAIL: Caution Opening Links or Files

Attached are the draft permits for the Barry Unit 8 & 9 project. Please review and respond with any comments you have by July 10th. Let me know if additional time is needed.

Regards,

TYLER PHILLIPS
Environmental Engineering Specialist, Senior
Industrial Minerals Section
Energy Branch, Air Division
Alabama Department of Environmental Management
tyler.phillips@adem.alabama.gov
(334) 271-7867

Phillips, Tyler

From: Phillips, Tyler
Sent: Thursday, July 23, 2020 10:11 AM
To: Howard, Nikia
Cc: Steele, C. Mark
Subject: RE: Barry U8&9 Project

Thank Nikia, I also wanted the control efficiencies of the chosen control options when there are multiple technically and economically feasible options. Sorry if I didn't make that clear. Could you provide the control efficiencies for the SCR/DLNB on the NGCC and the ULNB for the Aux Boiler?

Tyler

From: Howard, Nikia <NHoward@southernco.com>
Sent: Thursday, July 23, 2020 9:32 AM
To: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Cc: Steele, C. Mark <CMSteele@southernco.com>
Subject: RE: Barry U8&9 Project

Tyler,

Please see the additional information below that you requested for the project. Control efficiencies have been provided for water/steam injection for CC units and SCR for auxiliary boilers.
If you have any questions, please let me know.

Combined Cycle Combustion Units

1. NOx control –
    a. Proposed BACT: SCR in combination with dry low NOx combustors
    b. Water or steam injection – 60% control
    c. Good combustion practices – "base" level of emissions performance; no control efficiency
2. CO control –
    a. Proposed BACT: oxidation catalyst in combustion with combustion controls/good combustion practice
    b. Other technically feasible alternatives - none
3. VOC control –
    a. Proposed BACT: oxidation catalyst in combustion with combustion controls/good combustion practice
    b. Other technically feasible alternatives – none
4. PM control –
    a. Proposed BACT: combustion controls/good combustion practice with natural gas firing
    b. Other technically feasible alternatives – none
5. GHG control –
    a. Proposed BACT: energy efficiency with low carbon (natural gas) fuel
    b. Other technically/economically feasible alternatives – none

Auxiliary Boiler

1. NOx control –
    a. Proposed BACT: Ultra Low NOx burners
    b. **SCR – 85-90% control** (equivalent or lower control efficiency than ULNBs)
2. CO and VOC control –
    a. Proposed BACT: Good combustion practice and burner design

b. Oxidation catalyst: equivalent to or somewhat lower control efficiency than GCP per EPA's RBLC

3. PM control –
   a. Proposed BACT: good combustion practice with natural gas firing
   b. Other technically feasible alternatives – none

Emergency Diesel Engines (Electric Generators and Firewater Pump)

1. NOx, CO & VOC control –
   a. Proposed BACT: Engine design, combustion controls & good combustion practices
   b. Other technically feasible alternatives – none
2. PM control –
   a. Proposed BACT: Ultra low sulfur/low ash fuel
   b. Other technically feasible alternatives - none

Cooling Tower

1. PM control –
   a. Proposed BACT: drift eliminators
   b. Other technically feasible alternatives – none

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

Alabama Power

From: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Sent: Thursday, July 02, 2020 8:42 AM
To: Howard, Nikia <NHoward@southernco.com>
Cc: Steele, C. Mark <CMSteele@southernco.com>
Subject: RE: Barry U8&9 Project

EXTERNAL MAIL: Caution Opening Links or Files

A small range would be okay. We want to see control efficiencies when there are multiple technically and economically feasible control options for a unit and pollutant and not all of the technically and economically feasible controls are applied. If there are multiple options and they are all applied then I don't need the control efficiency. Some examples, if the only SO2 technically and economically feasible control option for the engines is low sulfur diesel, then I don't need the control efficiency. If you have combustion controls and GCP as the options for another pollutant but both are being applied, then I don't need the efficiency. Its for times when there are multiple options for a given unit and pollutant, such as NOx on the NGCC with water injection, dry low no combustor, and SCR, but at least one technology is not applied that I need the control efficiencies.

From: Howard, Nikia <NHoward@southernco.com>
Sent: Thursday, July 2, 2020 8:11 AM
To: Phillips, Tyler <tyler.phillips@adem.alabama.gov>

Cc: Steele, C. Mark <CMSteele@southernco.com>
Subject: RE: Barry U8&9 Project

Tyler,

Is a control efficiency range acceptable to provide for these options? We wanted to provide efficiencies that are readily available from the RBLC or the industry for the different technologies.

Also, do you want us to provide efficiencies for all of the control technologies provided? For example, do you want us to provide it where we have listed combustion controls and good combustion practices?
Do you want the efficiencies for the emergency equipment and cooling towers?

From: Phillips, Tyler <tyler.phillips@adem.alabama.gov>
Sent: Thursday, June 25, 2020 11:09 AM
To: Howard, Nikia <NHoward@southernco.com>; Steele, C. Mark <CMSteele@southernco.com>
Subject: Barry U8&9 Project

EXTERNAL MAIL: Caution Opening Links or Files

We would like to see some additional information for the Unit 8 & 9 project. For pollutants/units with more than one technically and economically feasible control option, please provide the control efficiencies for the technically and economically feasible options.

Feel free to contact me if you wish to discuss or have any questions.

Regards,

TYLER PHILLIPS
Environmental Engineering Specialist, Senior
Industrial Minerals Section
Energy Branch, Air Division
Alabama Department of Environmental Management
tyler.phillips@adem.alabama.gov
(334) 271-7867

Alabama Power Company
Plant Barry Combined Cycle Project
Air Construction Permit Application
Response to ADEM Modeling Comments

ADEM Modeling Comment #1: Please add a MERP column in the NAAQS table to clearly show how it was added to the final concentration.

Response: The NAAQS and PSD increment results in Tables 8-2 and 8-3 (shown below) from the February 2020 PSD Application have been updated in accordance with ADEM's request to show the MERPs $PM_{2.5}$ secondary concentration that was added to the model concentration to determine compliance. The MERPs-derived secondary $PM_{2.5}$ concentrations are based on data presented in Table 6-9 of the PSD Application submitted in February 2020. In addition, as noted in response to comment #5, the NAAQS results reflect the additional background sources included in the modeling.

Table 8-2: Summary of NAAQS Analysis

Pollutant	Averaging Period	Rank	Modeled Concentration (μg/m³)(1)	MERPs Secondary Concentration (μg/m³)(2)	Ambient Background Concentration (μg/m³)(3)	Total Concentration (μg/m³)(4)	NAAQS (μg/m³)	Complies (Y/N)?
NO_2	1-hour	98th Percentile Peak Daily 1-hr 5-year Average	85.84 (0.83)	n/a	31.0	116.84	189	Yes
$PM_{2.5}$	24-hour	98th Percentile 24-hr 5-year Average	11.53 (0.79)	0.092	17.0	28.62	35	Yes
	Annual	5-year Average	2.13 (0.25)	0.002	8.1	10.23	12	Yes

(1) Modeled contribution in parentheses represent Project contributions.
(2) MERPs secondary $PM_{2.5}$ concentration based on data from Table 6-9.
(3) Ambient background concentrations take from Table 6-12.
(4) Total concentration includes project, nearby sources, monitored background concentrations, and secondary $PM_{2.5}$.

Table 8-3: Summary of PSD Increment Analysis

Pollutant	Averaging Period	Rank	Modeled Concentration (μg/m³)	MERPs Secondary Concentration (μg/m³)(1)	Total Concentration (μg/m³)(2)	PSD Increments (μg/m³)	Complies (Yes/No)?
$PM_{2.5}$	24-hour	Highest 2nd Highest over 5 years	4.42	0.092	4.51	9	Yes
	Annual	Highest Annual Average	0.46	.002	0.46	4	Yes

(1) MERPs secondary $PM_{2.5}$ concentration based on data from Table 6-9.
(2) Total concentration includes project, nearby sources, and secondary $PM_{2.5}$.

ADEM Modeling Comment #2: Please add a MERP column in the SIL and Increment table to clearly show how it was added to the final concentration. If you don't do that please remove verbiage saying the MERP was added.

Response: The SIL results in Table 7-4 (shown below) from the February 2020 PSD Application has been updated in accordance with ADEM's request to show the MERPs $PM_{2.5}$ secondary concentration that was added to the model concentration when comparing to the SILs.

Table 7-4: Summary of Maximum AERMOD Concentrations to Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration (µg/m³)		SIL (µg/m³)	Significant? (Yes or No)
		AP Land Use	SITE Land Use		
NO_2	1-hour	10.8	11.1	7.5	Yes
	Annual	0.62	0.73	1	No
PM_{10}	24-Hour	3.23	4.92	5	No
	Annual	0.41	0.43	1	No
$PM_{2.5}$ Modeled	24-Hour	3.07	4.27	1.2	Yes
	Annual	0.36	0.38	0.3	Yes
$PM_{2.5}$ MERPs Secondary(1)	24-Hour	0.092		1.2	Yes
	Annual	0.002		0.3	Yes
$PM_{2.5}$ Total(2)	24-Hour	3.16	4.36	1.2	Yes
	Annual	0.36	0.39	0.3	Yes
CO	1-Hour	37.0	34.8	2,000	No
	8-Hour	26.2	28.8	500	No
SO_2	1-Hour	1.83	2.51	7.9	No
	3-hour	1.9	2.5	25	No
	24-hour	0.7	1.7	5	No
	Annual	0.1	0.1	1	No

(1) MERPs secondary $PM_{2.5}$ concentration based on data from Table 6-9.
(2) Total concentration includes project and secondary $PM_{2.5}$.

ADEM Modeling Comment #3: Please add a visibility statement to the soils section.

Response: The following sentence existing in the last paragraph of Section 9.2 on page 9-2 of the PSD Application was added to address visibility.

"In addition, demonstration of compliance with the 24-hour PM_{10}/$PM_{2.5}$ and 1-hour NO_2 NAAQS would also indicate that the Project should not have any nearby impacts associated with visible plumes."

If the Project's impact associated with visible plumes needs to be addressed further, we will coordinate with ADEM when submitting page changes associated with updates to the PSD Application.

ADEM Modeling Comment #4: Please add an addendum of all correspondence with the FLM concerning Breton.

Response: Attached is the correspondence with the FLM regarding the proposed Project's impact on Breton. Alabama Power emailed the FLM initially on October 1, 2019 followed-up by another email on November 21, 2019. Although official email correspondence was not received, Ms. Collins verbally confirmed that an AQRV analysis for the Project would not be necessary. This was communicated to ADEM on March 13, 2020.

ADEM Modeling Comment #5: Please add an addendum of the ADEM provided inventories used in the NAAQS and increment modeling.

Response: Alabama Power has conducted revised NAAQS modeling with an updated $PM_{2.5}$ background source inventory provided by ADEM, which included additional sources based on a slight shift in the Project's Significant Impact Area. The updated inventory included one additional NAAQS source and one PSD increment expanding source. Since the modeling conservatively excluded increment expanding sources, only the NAAQS modeling was revised. The updated NAAQS modeling files were provided to ADEM on February 28, 2020 and should replace what was in the original modeling archive submittal that accompanied the February 2020 PSD application as Appendix G. The additional source included in the 24-hour and annual PM2.5 NAAQS modeling is shown below.

Facility No.	Stack Description	Stack No.	Stack Type	UTM Coordinates East	UTM Coordinates North	Increment Type	Allowable (lb/hr)	actual (lb/hr)	Base Elev. (m)	Stack Ht. (m)	GEP (m)	Stack Dia. (m)	Exit Temp. K	Velocity (m/s)
503-8065	Meltshop Baghouse	001	V	403.50	3423.58	Baseline Source	27.25		9.14	53.34		7.62	392	16.56

Please note the modeling results shown in Table 8-2 above reflect the revised modeling results, showing very little change in only the 24-hour modeled $PM_{2.5}$ concentration.

From: Howard, Nikia
To: "Healan, Geoffrey"
Cc: Steele, C. Mark; "Bacon, Leigh"
Subject: RE: Request for Determination of Need for Class I AQRV Modeling Analysis
Attachments: image001.gif

Geoff,

I just wanted to follow-up with you regarding our communications with the FLM about a screening level determination for the Plant Barry Combined Cycle Project. I made several attempts to receive written correspondence regarding the Project, but was not able to do so. I did, however, receive verbal confirmation from Ms. Collins that an AQRV analysis for the Project would not be necessary and that the Project would be screened out since the Q/d ratio was less than 10.

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

From: Howard, Nikia
Sent: Thursday, November 21, 2019 11:39 AM
To: 'Catherine_Collins@fws.gov' <Catherine_Collins@fws.gov>
Subject: RE: Request for Determination of Need for Class I AQRV Modeling Analysis

Ms. Collins,

Please find attached an updated form with the CBI note removed. There has also been an update to the emissions calculations (removed 1 of the auxiliary boilers from the project) from the previous submittal. The total sum of the relevant emissions is now 611 tons per year for the project. This will result in an updated Q/d ratio of 4.6.

Thank you for considering our request for a screening level determination. If you have any questions, or need any additional information, please let me know.

Thanks,

Nikia Howard
Alabama Power - Air Compliance

Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

From: Howard, Nikia
Sent: Tuesday, October 01, 2019 3:32 PM
To: Catherine_Collins@fws.gov
Cc: Phillips, Tyler <tyler.phillips@adem.alabama.gov>; Healan, Geoffrey <GAH@adem.alabama.gov>; Steele, C. Mark <CMSteele@southernco.com>; Connors, Jeffrey <Jeffrey.Connors@aecom.com>
Subject: Request for Determination of Need for Class I AQRV Modeling Analysis

Ms. Collins,

Alabama Power Company (APC) proposes to construct up to 2 new natural gas-fired combined cycle generating units located at Barry Steam Electric Generating Plant (Plant Barry) with a nominal generating capacity of up to 1,486 megawatts (MW). Plant Barry is located approximately 20 miles north of Mobile, Alabama. APC is developing an air permit application for submittal to the Alabama Department of Environmental Management (ADEM) for the issuance of an Air Permit authorizing construction of this project. Federal and ADEM regulations require notice of these type permit applications to the appropriate Federal Land Manager of nearby Class I Areas.

The proposed project is located approximately 132 km from the Breton National Wildlife Refuge Class I Area. There are no other Class I Areas within 300 km of Plant Barry.

The FLAG 2010 guidance states that proposed sources with a Q/d ratio less than 10 will likely not have an adverse impact on a Class I Area. As I'm sure you are aware, the Q in the Q/d is the sum of the SO_2, NO_X, H_2SO_4, and PM emissions from the project expressed in tons/year. Conservatively, the total sum of the relevant emissions is 619 tons per year for the this project. The project scope does not include any backup fuel capability. The d in the Q/d is the distance (km) from the source to the Class I Area of interest; in this case Breton National Wildlife Refuge. Regarding this project relative to Breton, Q=619 and d=132, and the resultant Q/d ratio = 4.7. This is far less than 10, the screening level suggested in the FLM guidance. Given this low Q/d ratio, APC believes an AQRV modeling analysis for regional haze and deposition of Breton National Wildlife Refuge Class I Area is not warranted.

Please find attached a completed Southern Region US Forest Service "Request for Determination of Need for a Class I AQRV Modeling Analysis" form that provides all the relevant information for the US Fish and Wildlife Service to make their determination regarding this project. It would be greatly appreciated if you could provide a response within the next two weeks as ADEM requires your determination to be included in the air permit application.

Please note that Alabama Power considers information contained in this request to be **Confidential Business Information**. Accordingly, do not disclose or release any information contained in this email or attachment.

Thank you for considering our request and we look forward to your response. If you have any questions, please contact me.

Thanks,

Nikia Howard
Alabama Power - Air Compliance
Tel 205.257.3212
Mobile 205.259.0655
nhoward@southernco.com

Phillips, Tyler

From: Phillips, Tyler
Sent: Thursday, April 2, 2020 10:59 AM
To: Mark Steele (CMSteele@southernco.com)
Cc: Youngpeter, Jennifer S; Carr, Doug
Subject: Barry PSD Application Comments
Attachments: Barry PSD Application Comments.docx

Mark,

See attached document for my comments on the Barry PSD application. Please review, address, and respond to these comments by May 1st.

Feel free to give me a call to discuss the comments once you've had a chance to review them.

Regards,

TYLER PHILLIPS
Environmental Engineering Specialist, Senior
Industrial Minerals Section
Energy Branch, Air Division
Alabama Department of Environmental Management
tyler.phillips@adem.alabama.gov
(334) 271-7867

APC – Barry PSD Application Comments

1. Some units discuss the expected emission rates for various pollutants but don't include emission limit in BACT proposal.
    a. Need SO2 emission limits included in proposal for BACT for CC, Aux Boiler.
2. Proposed NGCC BACT limits requested lb/hr only. Will also need limits for all levels of operation, could use ppm ratings or lb/MMBtu limits in addition to lb/hr.

    From '90 NSR guidance, BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements).
3. FGD or add on SO2 controls not being technically feasible for NGCC, small natural gas-fired boilers, and emergency engines due to the expected level of SO_2 emissions from the units being lower or orders of magnitude lower than the outlet concentrations of other combustion sources utilizing FGD control technology doesn't prove technical infeasibility. If the concentration of SO2 is so low that the FGD technology is not effective or the unit cannot operate properly with the control installed, then that would make it technically infeasible. Otherwise, further analysis should be done.
4. Very little discussion as to specifically why technically infeasible control option is not feasible.
    a. FGR on boiler for VOC/CO.
5. Considered technically feasible but ruled out due to not being "top-level" control or ruled out without energy, environmental, and economical analysis performed.
    a. SCR NOx on boiler. When ranking options, were commercially available SCR control options researched or was it assumed that due to BACT limits in RBLC that SCR wouldn't be any better than LNB/ULNB?
    b. Oxidation catalyst for CO/VOC from boiler, if its technically feasible it should be ranked and evaluated under Step 4 of BACT analysis.
6. Controls identified from RBLC having no further discussion about feasibility.
    a. Cooling tower TDS limit
7. Need proposed GHG limit for Aux Boiler.
8. Control technologies precluded from analysis due to not being in NSPS regulations. EPA NSR guidance states, "The fact that a NSPS for a source category does not require a certain level of control or particular control technology does not preclude its consideration in the top-down BACT analysis."
    a. PM control on aux boiler. (Explain why not technically feasible)
    b. Tier IV controls on emergency engines (NOx, VOC, PM). This seems like a demonstrated control technology for emergency generator engines, and you cannot ignore 4 BACT listings due to "emergency diesel engines are not required to meet Tier IV emission limits". Guidance doc also states that vendor info should be considered. Cummins has commercially available tier 4 engines that can be used for "emergency backup assurance". https://www.cummins.com/generators/tier-4-certified-generator-sets
9. NSPS applicability section of application talks about diesel storage tanks. No emission calculations or forms for new tanks. New emissions sources? If so, form 108 for tanks (Items 1-6 and Tables 1-3 as applicable) should be submitted to verify tank applicability.

Alabama Power Company
Plant Barry Combined Cycle Project
Air Construction Permit Application
Response to ADEM Comments

Response to Comments #1 and #2 Regarding NGCC Emission Limits

The proposed SO_2 limits for the combined cycle units and the auxiliary boiler have been updated in the table below. The proposed limits for the combined cycle units have been updated to also include emission limits on a lb/mmBtu basis.

Table 5-5: Proposed BACT Emission Limits and Compliance Demonstration Methods

	Proposed Emission Limits	Compliance Demonstration Methods
Combined Cycle Units (per unit)		
Nitrogen Oxides	39.1 lb/hr[1] 0.008 lb/mmBtu	EPA Reference Method 7 or 7E
Carbon Monoxide	23.8 lb/hr[1] 0.005 lb/mmBtu	EPA Reference Method 10
Volatile Organic Compounds	13.6 lb/hr[1] 0.003 lb/mmBtu	EPA Reference Method 25, 25A, or 25B
Particulate matter (PM10/PM2.5)	21.51 lb/hr 0.004 lb/mmBtu	EPA Reference Method 5, 17 or 201 and 202
Sulfur Dioxide	0.002 lb/mmBtu 0.6 gr/100 scf	EPA Reference Method 6, Annual Fuel Sampling
Greenhouse Gases (CO_2e)	2,445,022 ton/yr	CEMS, Fuel Use Monitoring
Auxiliary Boiler		
Sulfur Dioxide	0.002 lb/mmBtu 0.6 gr/100 scf	EPA Reference Method 6, Annual Fuel Sampling

[1] The proposed pound per hour emissions rates are based on a concentration of 2 ppm @ 15% O2 each for NOx, CO, and VOC, consistent with the vendor guarantees for these pollutants under normal operating conditions

Received 5/1/2020 TSP

Response to Comment #3 Regarding SO_2 Controls

Sections 5.2.5.1, 5.3.4.1, and 5.4.3.1 of the Air Construction Permit Application Technical Support Document (TSD) have been updated to include language to address the technical infeasibility of SO_2 controls for the combined cycle units, auxiliary boiler, and emergency engines. The revised sections are as follows:

5.2.5.1 Steps 1 & 2 –Technical Feasibility Assessment for SO_2 Emission Control Alternatives

A search of EPA's RBLC was performed to identify large natural gas-fired combined-cycle units permitted since 2008 with BACT determinations for SO_2. This search identified a total of 49 listings of units in this category with BACT determinations for SO_2; all of these listings describe the use of natural gas or clean fuel as the control technology that was concluded to be representative of BACT. An additional 12 listings also list efficient combustion or GCP as representative of BACT. The results of this RBLC search are summarized in Appendix E, Table E-5.

Flue gas desulfurization (FGD) is a post-combustion alternative that has been utilized to control SO_2 emissions from certain combustion sources that utilize high sulfur-content fuels, including coal-fired and residual oil-fired boilers. EPA concluded that FGD use on these units would be unreasonable when emission standards for combustion turbines were initially proposed under the NSPS program. At that time, the Agency selected the firing of low sulfur fuels as the basis of the proposed standards of performance[1]. Similarly, the use of low sulfur fuel was proposed as the basis of the SO_2 emission standard in the most recent revision of the NSPS for combustion turbines, and FGD was not identified by EPA as an available SO_2 emission control alternative for combustion turbines when the revised NSPS was promulgated[2]. Moreover, none of the RBLC listings for large combined cycle turbines list FGD as having been applied to units in this source category. FGD systems would not be capable of any practical level of emission control and have not been demonstrated on natural gas-fired combined cycle units. The SO_2 emissions rate from the proposed combined cycle units is nearly two orders of magnitude lower than the outlet emission rates that have been achieved on other combustion sources that have used FGD. Consequently, FGD is not a technically feasible SO_2 control option for natural gas-fired combined cycle units; the only technically feasible and top-level alternative to control SO_2 emissions from these units is the use of low sulfur fuels, including natural gas.

5.3.4.1 Steps 1 - 4 – Technical Feasibility Assessment and Ranking of Auxiliary Boiler SO_2 Emissions Control Alternatives

When standards of performance for small boilers were proposed under the NSPS program, EPA declined to establish SO_2 emission limits for natural-gas fired units because of the low uncontrolled emission levels associated with them[3]. As with natural gas-fired combined cycle units, the use of FGD would not be capable of any practical level of emission control on natural gas-fired boilers because the SO_2 emissions from these units are considerably lower than the outlet emission rates that have been achieved on other combustion sources using FGD. Also, the use of FGD systems on natural gas-fired auxiliary boilers has not been demonstrated on auxiliary boilers.

A review of the RBLC was conducted to identify available alternatives to control SO_2 emissions from small natural gas-fired boilers. The RBLC search results are presented in Appendix E, Table E-11. A total of 53 natural gas-fired boilers with BACT limits for SO_2 were identified. The emission control alternative that is identified as BACT for SO_2 was included in 42 of these listings. The use of natural gas or clean fuel was identified as BACT for 39 listings, and good combustion practices was identified as BACT for 12 listings.

---

[1] 42 Fed. Reg. at 53,785.

[2] 70 Fed. Reg. at 8,320.

[3] *Id.* at 24,804.

None of these RBLC listings identified FGD as having been applied to small natural gas-fired boilers. In addition, EPA has noted that "Because of these low uncontrolled SO_2 emission levels, the application of any control technology to natural gas-fired steam generating units would entail unreasonable costs"[4]. Accordingly, evidenced by these listings and the unreasonable costs of additional controls, the exclusive firing of natural gas is the top-level alternative for control of SO_2 emissions from small natural gas-fired boilers.

5.4.3.1 Steps 1 - 4 - Technical Feasibility Assessment and Ranking of Emergency Diesel Engine SO_2 Emission Control Alternatives

EPA declined to establish emission limits for SO_2 from emergency diesel engines when the new source performance standards for units in this category (i.e., 40 CFR 60 Subpart IIII) were proposed because the use of low sulfur fuel was determined to be the best demonstrated technology. At the time, the agency explained that limits on SO_2 emissions from diesel engines were not warranted because the recent revisions to the transportation diesel fuel standards - adoption of ultra-low sulfur diesel fuel requirements - would result in decreases in SO_2 emissions from these units[5]. Post-combustion SO_2 control alternatives are not technically feasible because the control of SO_2 emissions from diesel engines is achieved by removing the sulfur from the fuel prior to use. Therefore, post-combustion control alternatives are not available for diesel engines and have not been demonstrated on these engines.

A review of the RBLC was conducted to identify available alternatives to control SO_2 emissions from emergency diesel engines. The RBLC search results are presented in Appendix E, Table E-17. A total of 71 engines with BACT limits for SO_2 were identified. The emission control alternative that is identified as BACT for SO_2 was included in 49 of these listings. The use of ultra-low sulfur diesel (ULSD) fuel containing no more than 15 ppm sulfur was identified as BACT for 36 listings of these listings; good combustion practices was identified as BACT for 13 listings. Accordingly, it can be concluded that the firing of low sulfur diesel fuel is the only technically feasible alternative for control of SO_2 emissions from emergency diesel engines, and the firing of ULSD is the top-level control alternative.

---

[4] *Id.* at 24,804.

[5] *Id.* at 39,879.

Response to Comments #4a and #5b Regarding FGR and Oxidation Catalyst

For the auxiliary boiler, Section 5.3.2.1 of the TSD has been updated to address technical infeasibility of flue gas recirculation and Section 5.3.2.2 has been updated to address technical infeasibility of the oxidation catalyst.

5.3.2.1 Step 1 - Available Auxiliary Boiler CO and VOC Control Alternatives

A review of the RBLC was conducted to identify available alternatives to control CO and VOC emissions from small natural gas-fired boilers. The RBLC search results are presented in Appendix E, Tables E-8 and E-9.

A total of 101 units with BACT limits for CO in the same size range as the auxiliary boiler (<100 MMBtu/hr heat input) were identified. The emission control alternative that is identified as BACT for CO was included in 83 of these listings. Good combustion and burner design (i.e., ULNBs, LNBs, combustion control and/or good combustion practices) was identified as BACT for 69 of these listings. Use of an oxidation catalyst system was identified as BACT in two listings (Footprint Power in Salem, MA and the Marshalltown Generating Station in Marshalltown, IA). Use of flue gas recirculation or exhaust gas recirculation alone was identified as BACT in four listings, and the use of clean fuel or natural gas alone was identified in two listings.

Similarly, a total of 90 units with BACT limits on VOC emissions from small boilers were identified in the RBLC search. The alternative that was identified as BACT for VOC was included in 69 of these listings. As with CO, good combustion and burner design (58 listings), catalytic oxidation (one listing), flue gas recirculation or exhaust gas recirculation alone (four listings), and the use of clean fuel or natural gas alone (two listings) are the specific alternatives that are described as being used to control VOC emissions. An additional four listings describe "boiler operation in conformance with manufacturer's specifications" as BACT.

EPA states that the emission rates of CO and VOC from natural gas-fired boilers depend principally on their fuel combustion efficiency, noting specifically that "...VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air."[6] EPA also notes that some measures to reduce NOx emissions, including the use of flue gas recirculation, can reduce combustion efficiency, resulting in increased CO and VOC emissions.

Although several boiler listings in the RBLC identify flue gas recirculation (either alone or in combination with other measures) as having been concluded to be representative of BACT for CO or VOC, this alternative has not been described by EPA or boiler manufacturers as a control technique for these pollutants. Rather, as described above in the section on Ultra Low NOx Burners, flue gas recirculation is a means to reduce NOx formation. The RBLC listings that suggest that flue gas recirculation has been concluded to be BACT for CO or VOC also list this alternative as BACT for NOx, and thus the inclusion of flue gas recirculation as a control alternative for CO or VOC may have been made in error.

Accordingly, flue gas recirculation is not considered to be a control alternative for CO or VOC emissions from natural gas-fired boilers.

Oxidation Catalyst

As described in Sections 5.2.2.2 and 5.2.3.2, an oxidation catalyst system is a post-combustion technology that removes CO and VOC from the exhaust gas of a combustion source. Oxidation catalyst systems are more generally applied within the HRSG for combined cycle units and to larger boilers. Such systems must

---

[6] AP-42: Compilation of Emission Factors – Section 1.4: Natural Gas Combustion (1998)

be installed in an appropriate location within the tube passes of a boiler where the exhaust gas temperature is within the appropriate range, which varies depending on catalyst formulation. Further, effective oxidation catalyst control requires a limited space velocity across the surface of the catalyst and to limit pressure drop across the catalyst grid. For these reasons, there are few examples of the application of oxidation catalyst systems to control CO or VOC emissions from small natural gas-fired boilers.

Good Combustion and Burner Design

The fundamental design criteria for fuel burners is to maximize combustion efficiency, and thereby minimize the formation of products of incomplete combustion. Good combustion practices thus optimize combustion and heat liberation with specific burner design features (such as optimization of the combustion air-to-fuel ratio and promotion of complete air/fuel mixing) that results in minimization of CO and VOC formation.

5.3.2.2 Steps 2-4 - Technical Feasibility, Ranking and Effectiveness of Auxiliary Boiler CO and VOC Control Alternatives

EPA's RBLC contains very few examples of operating facilities that have employed add on-controls, such as oxidation catalyst systems, to control CO or VOC emissions from small boilers. Although this alternative along with good combustion/burner design are technically feasible alternatives for control of these pollutants from small boilers in some settings, an oxidation catalyst is not technically feasible for the proposed auxiliary boiler. Here, the boiler is expected to operate for short periods of time, typically operating for up to a few hours prior to each startup of the combined cycle units. Due to the expected intermittent operation of the auxiliary boiler, the boiler will not consistently have the appropriate exhaust gas temperature range necessary for effective application of the oxidation catalyst, and the temperature range may not be achieved at all during short duration boiler operating periods. As such, an oxidation catalyst to control CO or VOC emissions is not technically feasible for the proposed auxiliary boiler.

For small auxiliary boilers with oxidation catalysts, the lowest CO emissions level in the RBLC is 0.0035 lb/MMBtu for the auxiliary boiler at the new Footprint Power facility in Salem, MA. This facility, which was permitted in 2014 has only recently begun operation and information is not yet available to conclude that the permitted emission level on this boiler has been demonstrated.

The lowest VOC emissions level in the RBLC for small boilers where the emission control alternative is identified is 0.0017 lb/MMBtu for the auxiliary boiler at Black Hills Power's Cheyenne Prairie Generating Station near Cheyenne, WY, which lists good combustion practices as the control method.

Good combustion practices and burner design features to ensure complete combustion have been concluded to be representative of BACT for most of the small boilers listed in the RBLC with limits on CO. For CO, the emission limits for these measures in the RBLC listings is from 0.0075 to 0.25 lb/MMBtu, with majority of the listings having limits below 0.040 lb/MMBtu. Of the 42 small boilers included in the RBLC that were permitted within the past 5 years, 19 have CO limits below 0.040 lb/MMBtu, with 15 listings having emission limits between 0.030 and 0.040 lb/MMBtu.

Good combustion practices and/or burner design features to ensure complete combustion have also been concluded to be representative of BACT for most of the small boilers listed in the RBLC with limits on VOC. For VOC, the emission limits in the RBLC listings where the emission control technology is identified range from 0.0017 to 0.054 lb/MMBtu. The lowest emission level from among these listings (for the 25 MMBtu/hr auxiliary boiler at the Cheyenne Prairie Generating Station in Wyoming) describes good combustion as BACT for VOC. A total of 34 boilers are listed as having been permitted within the past 5 years; 21 of these have VOC limits below 0.0060 lb/MMBtu, and ten have emissions limits between 0.0030 and 0.0050 lb/MMBtu.

Response to Comment #5a Regarding SCR

Section 5.3.1.2 of the TSD has been updated to address the technical feasibility of SCR for the auxiliary boiler. Although post-combustion control of NOx emissions with an SCR is generally a technical feasible option, it is not technically feasible for the proposed auxiliary boiler because the unit is expected be operated intermittently for short periods of time.

5.3.1.2 Step 2 - Technical Feasibility Assessment of Auxiliary Boiler NOx Control Alternatives

A review of the RBLC was conducted to identify and assess the emissions performance of available alternatives to control NOx emissions from small (<100 MMBtu/hr heat input capacity) natural gas-fired boilers. The RBLC search results are presented in Appendix E, Table E-7. A total of 109 natural gas-fired boilers with BACT limits for NOx in this size range were identified. The emission control alternative that is identified as BACT for NOx was included in 97 of these listings. LNBs or ULNBs (either alone or in combination with other alternatives) were identified as BACT for 92 listings, and SCR in combination with LNBs was identified for two listings.

Accordingly, LNBs, ULNBs, and SCR are all considered technically feasible emission control alternatives for the auxiliary boiler.

While SCR is generally a technically feasible NOx control technology for natural gas-fired boilers, it is not technically feasible for the proposed auxiliary boiler. The boiler is expected to operate for short periods of time, typically operating for up to a few hours prior to each startup of the combined cycle units. Due to the expected short duration and intermittent operating periods for the auxiliary boiler, the boiler will not consistently have the requisite flue gas temperature required for ammonia injection necessary for effective application of the SCR. As such, an SCR for NOx control is not feasible for this boiler.

5.3.1.3 Steps 3-4 - Ranking and Effectiveness of Available Auxiliary Boiler NOx Control Alternatives

NOx emission limits for small natural gas-fired boilers listed in the EPA's RBLC range from 0.007 to 0.200 lb/MMBtu (see Appendix E, Table E-7). Thirty-one of the 109 RBLC listings for boilers in this category have emission limits equal to or less than 0.011 lb/MMBtu. All but two of these 31 listings identify either UNLBs or LNBs alone as the boiler's emission control system for NOx, including the listing with the lowest emission level (the auxiliary boiler at the CPV Towantic Power Plant near New Haven, CT). The other two of these listings describe the NOx control system as the exclusive use of natural gas as fuel and limitations in the permitted operating hours.

There are two RBLC listings for small boilers that describe the NOx control system as the use of SCR in combination with LNBs (Valero Delaware City Refinery in Delaware and Sabina Petrochemicals LLC in Texas). The permit limits for these listings, however (0.015 lb/MMBtu and 0.020 lb/MMBtu) are higher than other units that utilize ULNBs or LNBs to control NOx emissions. Moreover, the heat input rate for the boiler at Sabina Petrochemicals LLC facility is actually 243 mmBtu/hr and should not be listed in the RBLC for natural gas fired boilers less than 100 mmBtu/hr. Additionally, both listings are for boilers that are designed to operate in a continuous baseload steam generating configuration rather than intermittent operation. Moreover, the NOx permit limits and controls for these units were established as the Lowest Achievable Emission Rate (LAER) rather than BACT because both units are located in areas that are classified as non-attainment for ozone. Because these boilers were intended for continuous operations and would be expected to have the flue gas temperatures and stable exhaust gas flow rates necessary for effective operation of an SCR, they are not similar to the proposed auxiliary boiler.

Accordingly, ULNBs and LNBs, which represented the best control levels, are considered the top level of NOx controls for small boilers. Emission limits in the range of 0.007 to 0.011 lb/MMBtu (6 to 9 ppm at 3% O_2) have been concluded to be representative of BACT.

Response to Comment #6a

The following sections of the TSD have been updated to address total dissolved solids restrictions for cooling towers.

5.5.1 Step 1 - Available Cooling Tower PM Control Alternatives

A review of the RBLC was conducted to identify available PM, PM10 and PM2.5 control measures for cooling towers. Based on a review of RBLC entries, there are no add-on control devices for cooling towers. Particulate matter emissions can be minimized by good design and operating practices, specifically the installation and use of high efficiency drift eliminators. The results of the RBLC review are presented in Appendix E Table E-19; a total of 27 cooling tower listings were identified. The emission control method was identified in all of these listings, and each listing identified the use of drift eliminators as BACT. The presence of high total dissolved solids (TDS) in the cooling water circulating through the cooling tower also affects particulate matter emissions, and three listings identified restrictions in the TDS content of the cooling tower recirculation water as an additional requirement. However, the Mobile River, which is the source of make- up water for the proposed cooling towers, already has a naturally low concentration of TDS in the water.

5.5.2 Steps 2-4 - Technical Feasibility Assessment and Ranking of Cooling Tower PM Control Alternatives

Drift eliminators consist of baffles located at the top of a cooling tower that are designed to prevent water droplets from escaping the tower by causing the droplets to change direction and lose velocity, and by impaction on the baffle blades resulting in agglomeration of droplets. Drift eliminators are the only available and most stringent means to minimize particulate matter emissions generated by cooling towers. As such, good design and operating practices, including the use of high efficiency drift eliminators, are the only control options for reducing PM emissions generated by a cooling tower. Therefore, high efficiency drift eliminators are the top control option for PM10/PM2.5 BACT for the cooling towers.

5.5.3 Step 5 - Evaluation of BACT for Cooling Tower PM Control

Alabama Power will utilize drift eliminators on the new cooling towers proposed for the Project. The cooling towers will have a maximum drift rate equal to 0.0005% of the recirculated water flow. This is the only available and most stringent alternative to control particulate matter emissions from cooling towers and is, therefore, concluded to be representative of BACT.

Response to Comment #7 Regarding Auxiliary Boiler GHG Limit

For the auxiliary boiler, Section 5.3.5.3 of the TSD has been updated to include a tons per year limit for GHG.

5.3.5.3 Steps 4 and 5 - Proposed GHG Emissions Limits

Since efficient boiler design, cleaner fuels, and GCP are being considered in concert, ranking the effectiveness of each is not necessary. Alabama Power is proposing the use of efficient boiler design, cleaner fuels, and GCP as BACT for the auxiliary boiler. Additionally, Alabama Power proposes a limit of 46,416 tpy CO2e for the auxiliary boiler.

Response to Comment #8a Regarding PM Controls

The following sections of the TSD have been updated to address the infeasibility of PM controls on the auxiliary boiler.

5.3.3.1 Step 1 - Available PM, PM_{10} and $PM_{2.5}$ Auxiliary Boiler Control Alternatives

Available particulate matter control technologies include electrostatic precipitators, baghouses, good combustion practices, boiler design, and use of clean fuels. Electrostatic precipitators and baghouses have been used to control and reduce particulate matter emissions from boilers firing high ash fuels such as coal-fired boilers. Since natural gas is a clean fuel and not a high ash fuel, these technologies would have no practical application on gas-fired boilers, and they have not been demonstrated as a control technology for these boilers. Also, EPA concluded that uncontrolled particulate matter emissions from small natural gas-fired boilers are very low. As a consequence, the Agency concluded at the time the NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (i.e., 40 CFR 60, Subpart Dc) were proposed that application of add-on particulate matter controls to small natural gas-fired units would impose significant costs, and that "...the use of any conventional PM control technology to reduce PM emissions from small natural gas-fired steam generating units is considered unreasonable..."[7] Therefore, add on control systems such as ESPs and baghouses are not technically feasible particulate control options for natural gas-fired boilers.

A review of the RBLC was conducted to identify available particulate matter control alternatives for natural gas-fired boilers. The RBLC search results are presented in Appendix E, Table E-10. A total of 54 natural gas-fired boilers with heat inputs less than 100 MMBtu/hr with BACT limits for particulate matter were identified. The particulate matter emission control alternative identified as BACT was included in 43 of these listings. Equipment design, combustion control and/or good combustion practices (either alone or in conjunction with the use of clean fuels) were identified as BACT for 29 of these listings. Use of clean (low sulfur, low ash) fuels alone was identified as BACT for 14 listings.

5.3.3.2 Steps 2-4 - Technical Feasibility Assessment and Ranking of Auxiliary Boiler PM Control Alternatives

Boiler design, combustion control and the use of clean fuels are the only feasible and most stringent alternatives for control of particulate matter from the proposed auxiliary boiler. Because the only technically feasible control technology has been selected, a ranking of control technologies is not necessary.

5.3.3.3 Step 5 - Evaluation of BACT for Auxiliary Boiler PM Control

The most stringent particulate matter control method demonstrated for small natural gas-fired boilers is the use of combustion controls in conjunction with the firing of clean fuel (such as natural gas). Accordingly, the boiler design and combustion controls in conjunction with the exclusive firing of natural gas is concluded to be representative of BACT for control of $PM/PM_{10}/PM_{2.5}$ emissions from the proposed auxiliary boiler. These measures will limit particulate matter emissions to 0.0075 lb/MMBtu of PM_{10} or $PM_{2.5}$.

---

[7] *Id.*

Response to Comment #8b Regarding Controls on Emergency Engines

The following sections of the TSD have been updated to address emission controls identified for the emergency engines.

5.4.1.1 Steps 1-2 - Available Technically-Feasible Emergency Diesel Engine Control Alternatives for NOx, CO, and VOC

EPA began regulating NOx, CO and VOC emissions from diesel engines with the promulgation of the first tier of emission standards for mobile source non-road engines in 1994 under 40 CFR Part 89. Under these requirements, "volatile organic compounds" are referred to as "non-methane hydrocarbons" or NMHC. In the following discussions, NMHC shall hereinafter be referred to as VOC.

The NSPS for stationary diesel engines (40 CFR Part 60, Subpart IIII), including emission standards for NOx, CO, and VOC, were proposed in July 2005. At that time, EPA noted that the emission control strategies that were chosen for the non-road engine standards were appropriate for stationary diesel engines as well, because engine manufacturers stated that they generally do not design and manufacture separate diesel engines for mobile and stationary use[8]. EPA identified two types of emission controls for NOx, CO and VOC from stationary diesel engines when 40 CFR Part 60, Subpart IIII standards were proposed: engine-based technologies and aftertreatment-based technologies.

Engine-based technologies include inlet air cooling, fuel injection rate controls, injection timing retard, exhaust gas recirculation, control of air/fuel ratio, and control of air consumption. Collectively, these alternatives are referred to as engine design, combustion controls, and good combustion practices. The aftertreatment technologies to control these pollutants include SCR for NOx control and a diesel oxidation catalyst (DOC) for the control of CO.

For aftertreatment technologies, an SCR system can be installed on certain engine types for the control of NOx emissions. SCR systems must be operated within a certain temperature range and require the injection of a reductant (Diesel Exhaust Fluid or DEF) to reduce NOx emissions. In order for the catalyst to operate properly, the exhaust temperature must reach a certain temperature. Thus, during the warm-up period the engine can operate but without the benefits of NOx reduction from the SCR. For emergency standby engines, reaching these temperatures is difficult during routine maintenance, testing and short duration operations when the engine is typically operated at low load. In order to realize the NOx reduction benefits, the engine would need to be operated at higher loads and for longer periods of time than what is necessary for a standby emergency engine. DEF and maintenance should also be considered in an emergency standby engine application. Crystallization of the DEF is more likely to occur in emergency standby engines due to their infrequent operation. This crystallization can cause damage to the SCR and to the engine itself.

A diesel oxidation catalyst (DOC) can be installed on certain engine types for the control of CO and hydrocarbon emissions. This alternative is not feasible for emergency diesel engines because it must also be operated within a certain temperate range for CO and hydrocarbon emission reductions to occur. The DOC consists of a coated metal substrate that promotes oxidation of CO and hydrocarbons in the exhaust. The emission reduction potential is strictly dependent on exhaust gas temperature and such systems have little to no oxidation activity at low exhaust temperatures. Because oxidation systems impose backpressure on the engine's exhaust system, they are only technically feasible on engines that are specifically designed for their use, and they are generally not technically feasible for retrofit situations.

When promulgating 40 CFR Part 60, Subpart IIII, EPA reaffirmed its conclusion in the proposed rule that the use of engine-based technologies to meet the Tier 2 or Tier 3 engine standards, rather than the

---

[8] 70 Fed. Reg. 39,870, 39,882 (July 11, 2005)

aftertreatment technologies that constitute Tier 4 controls, represent the best demonstrated technology (BDT) for controlling emissions from emergency stationary diesel engines and emergency fire pump engines. The Agency concluded that standards based on the use of aftertreatment technologies were not justifiable for emergency stationary engines or emergency fire pumps "...due to the cost of the technology relative to the emission reduction that would be obtained."[9] As mentioned above, these technologies require the engines to meet certain operating conditions in order to be effective and would not be effective on emergency engines that are designed to start up quickly and operate for short periods of time. Accordingly, engine design, combustion controls, and good combustion practices are considered available alternatives for control of NOx, CO and VOC from emergency stationary diesel engines.

A review of the RBLC was conducted to identify available alternatives to control NOx, CO and VOC emissions from emergency stationary diesel engines in the same size ranges as for the planned emergency generators (1,500 kw or 2010 hp) and emergency fire water pump engine (316 hp). The emission control alternatives identified are summarized in the following table and the results are presented in Appendix E, Tables E-13, E-14, and E-15.

Table 5-3: Summary of EPA RBLC Listings for Emergency Stationary Diesel Engines

	NOx Listings	CO Listings	VOC Listings
Total Listings	184	169	121
Listings with control technologies identified	136	132	97
Engine design or certification	76	80	43
Good combustion	78	76	56
Clean fuels/ULSD	25	22	18
Operating hours limitation	29	20	16

None of these listings identify the use of aftertreatment controls (DOC or post-combustion NOx controls) as BACT for NOx, CO, or VOC for emergency stationary diesel engines. Accordingly, the use of engine-based technologies can be concluded to be the only technically-feasible means to control NOx, CO, and VOC emissions from emergency stationary diesel engines and emergency stationary fire pump engines.

5.4.2.1 Step 1 - Available Emergency Diesel Engine PM Control Alternatives

As described in Section 5.4.1.1, when EPA promulgated the NSPS Subpart IIII emissions standards, it identified engine-based technologies as BDT to reduce emissions (including particulate matter emissions) from emergency stationary diesel engines and emergency fire pump engines. These alternatives are considered generally available for control of particulate matter from the proposed emergency diesel engines. The aftertreatment technology most often installed on engines to control emissions of PM is the diesel particulate filter (DPF) used in conjunction with ultra-low sulfur diesel fuel. In order to reduce PM emissions, the DPF typically uses a substrate made of a ceramic material to promote chemical reactions between gas-phase components of engine exhaust and soot particles that are collected in the filter. The collected particles must then be periodically burned off to regenerate the filter. Regeneration occurs when the exhaust temperatures increase promoting oxidation of the captured soot particles. While this is possible for non-emergency engines, it would require an emergency standby engine to run at a higher load for longer periods of time to allow exhaust temperatures to reach 600°C for an extended period of time. If a facility is

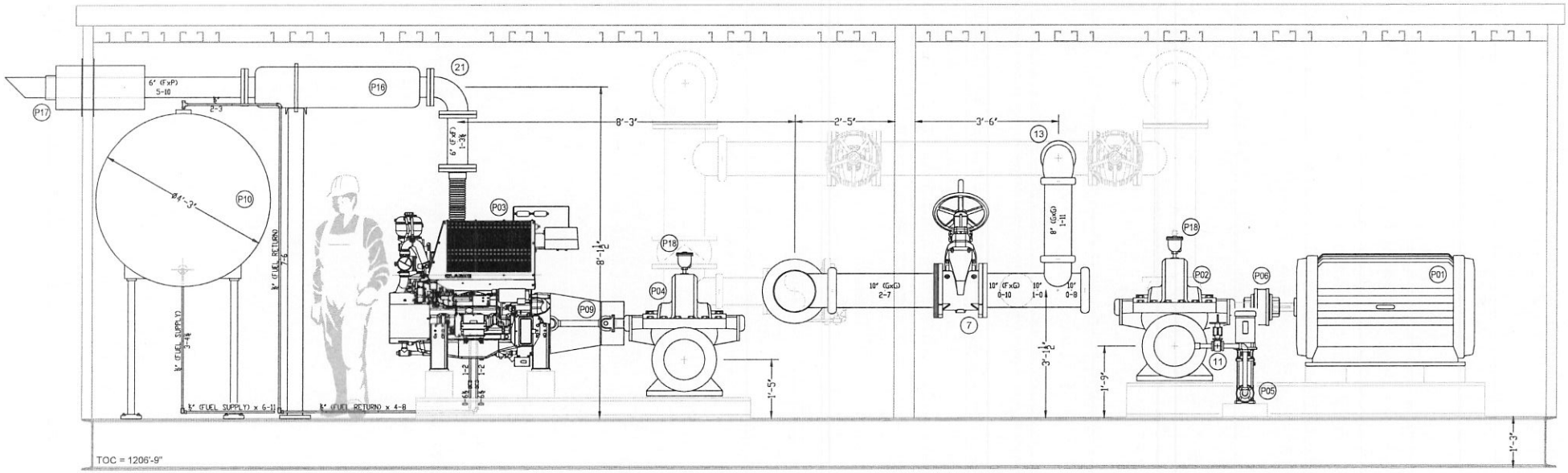
[9] *Id.* at 39,874.

not equipped with a load bank, it can become difficult to reach the load and temperature necessary for regeneration to occur. For these reasons, a DPF is not practical for emergency engines.

A review of the RBLC was conducted to augment identified alternatives to control particulate matter emissions from emergency diesel engines. The RBLC search results are presented in Appendix E, Table E-16. A total of 113 emergency diesel engines with BACT limits for particulate matter were identified. The emission control alternative identified as BACT for particulate matter was included in 86 of these listings. Engine design, combustion control and/or good combustion practices were identified as BACT for 67 of these listings, use of low sulfur fuel alone was identified as BACT for 7 listings, and a limitation on annual operating hours alone was identified as BACT for an additional listing. The use of a DPF was identified as BACT for four listings. The listings are emergency diesel engines planned for the Marshall Energy Center near Battle Creek, MI. This facility has not yet been constructed, and operation on an intermittent basis for these emission sources (such as emergency generators or emergency fire pump engines) has not yet been demonstrated. Moreover, the emission limits for these four listings (0.15 g/hp-hr) are consistent with the 40 CFR60, Subpart IIII requirements for emergency engines, which can be met without the use of a DPF. Engines with installed DPFs are normally designed to meet a more stringent emission limit. Therefore, a DPF is not technically feasible for the proposed emergency engines and has not been demonstrated on emergency engines that operate for short periods of time at low loads and temperature.

Response to Comment #9 Regarding Diesel Storage Tank

The diesel storage tanks are part of the fire pump engine assembly. Each storage tank is approximately 600 gallons. A diagram of the assembly is attached.


P17
6" (FxP)
5-10
P16
21
8'-3"
2'-5"
3'-6"
13
6" (FxF)
1-3
Ø1'-3"
P10
P03
P18
P04
P09
8'-1½"
1'-5"
10" (GxG)
2-7
10" (FxG)
6-10
10"
1-0
10"
0-8
8" (GxG)
1-11
7
3'-1½"
1'-9"
P02
P06
P01
11
P05
1'-3"
½" (FUEL RETURN)
7-5
½" (FUEL SUPPLY)
3-4
½" (FUEL SUPPLY) x 6-11
½" (FUEL RETURN) x 4-8
TOC = 1206'-9"