Preliminary Determination
Alabama Power Company – Plant Barry
503-1001

Introduction

On February 20, 2020**,** Alabama Power Company (APC) submitted an air permit application for a project to take place at Plant Barry located at 15300 Highway 43 North, Bucks, Mobile County, Alabama. Additional information was received on May 1, 2020. APC has proposed the addition of two (2) new natural gas-fired combined cycle (NGCC) units arranged in a 1-on-1 configuration. Ancillary equipment associated with the proposed project would include one (1) natural gas-fired boiler rated at 90.5 MMBtu/hr, two (2) diesel-fired emergency generator engines rated at 1,500 kilowatts (kW) each, one (1) diesel-fired emergency fire pump engine rated at 236 kW, and two (2) multi-cell mechanical draft cooling towers. Each NGCC unit would consist of a natural gas-fired combustion turbine, a heat recovery steam generator (HRSG) with a supplementary natural gas-fired duct burner, and a reheat condensing steam turbine generator. Additionally, each NGCC unit would be capable of producing a gross output of approximately 744 megawatts (MW).

Facility Description

The APC - Barry facility is an electric power generation facility currently with two (2) natural gas-fired steam electric generating units, two coal-fired steam electric generating units, and two (2) 2-on-1 NGCC units. 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 other small engines.

PSD

The proposed project would qualify as a major source modification since the emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), volatile organic compounds (VOC), and greenhouse gas emissions (GHG) would result in a net increase more than the significant emissions rates listed in ADEM Admin. Code r. 335-3-14-.04(1)(w). The proposed project would be subject to ADEM Admin. Code r. 335-3-14-.04 which was adopted pursuant to the federal requirements for prevention of significant deterioration (PSD).

PSD regulations were designed to limit pollutant concentration increases in areas that are cleaner than the National Ambient Air Quality Standards (NAAQS). The regulations establish increments that set ceilings on the amount of increased ambient pollutant concentrations that will be allowed in a PSD area. Sources subject to PSD regulations must comply with specific pre-construction review requirements.

A major source or major modification under a PSD review must be constructed with Best Available Control Technology (BACT). Additionally, the effects on soils, vegetation, visibility, and ambient air quality must be addressed for each applicable pollutant. If the net air emissions increase of any applicable pollutant is less than its significance emission rate, a PSD review is not necessary for that pollutant.

The following table shows the PSD significant emissions increase threshold values and worst-case net emission increases as specified in the application submitted:

Pollutant	PSD Significant Emission Rate (TPY)	Proposed Net Emission Rate Increase (TPY)	Significant Source
Particulate Matter (PM)	25	70.5	YES
Particulate Matter < 10µ (PM_{10})	15	189.7	YES
Particulate Matter < 2.5µ ($PM_{2.5}$)	10	183.7	YES
Sulfur Dioxide (SO_2)	40	70.9	YES
Nitrogen Oxides (NO_X)	40	350.2	YES
Carbon Monoxide (CO)	100	520.7	YES
Volatile Organic Compounds (VOC)	40	383.4	YES
Lead (Pb)	0.6	0.02	NO
Sulfuric Acid mist (H_2SO_4)	7	0.2	NO
Fluorides	3	0	NO
Total Reduced Sulfur	10	0	NO

Greenhouse Gases (GHG)(CO_{2e})	75,000	4,937,975	YES

BACT

The Clean Air Act prescribes several technology-based limitations affecting new or modified air pollution sources. Among these limitations is BACT. New or modified units located at a major source for PSD with significant net emission increases must be constructed with BACT, which is determined on a case-by-case basis, and addresses the energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that technology would bring.

NO_X

NO_X emissions are generated from fuel combustion and are a result of three (3) formation mechanisms: thermal NO_X from the dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air, fuel-derived NO_x from the oxidation of nitrogenous compounds that are present in the fuel, and prompt NO_x from the oxidation of hydrocarbon radicals near the combustion flame. NO_x controls typically either control NO_x emissions by reducing NO_x formation caused by combustion or reducing NO_x emissions after their formation via an add on control device.

Controls reducing formation of NO_x would include water or steam injection, combustor design features such as dry low-NO_x burners (LNB) and ultra-low NO_x burner (ULNB), and good combustion practices (GCP). NO_x emission reductions could also be achieved through post-combustion controls such as selective catalytic reduction (SCR) that uses ammonia or urea injected into the exhaust gas steam to react with NO_x to form nitrogen and water or selective non-catalytic reduction (SNCR) that uses high temperatures and a reducing agent such as ammonia or urea to reduce NO_x emissions.

NGCC Units

SCR systems, dry low NO_x combustors, and water or steam injection were identified with RBLC as being applied to natural gas-fired combustion turbines and are considered technically feasible NO_x control options. The application of a combined SCR control system and dry low NO_x combustor are considered technically feasible NO_x control measures, have been demonstrated on NGCC units, and would be considered the top-level control for these units. APC proposes low- NO_x burners, good combustion practices (GCP), an SCR control system, and NO_x emission limits of 31.9 lb/hr and 0.008 lb/MMBtu for BACT.

A review of the RBLC revealed that the proposed control design would provide NO_X control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for NO_X emissions from the NGCC units.

Auxiliary Boiler

SCR and SNCR systems and LNBs or ULNBs were identified as potential control options for small (<100 MMBtu/hr) natural gas-fired boilers. The application of an SCR control system is considered impractical, as the use of LNBs or ULNBs have been demonstrated to meet the top level of demonstrated NO_x control for small boilers in RBLC. A SNCR system would not be technically feasible due to the increased exhaust gas temperature required to initiate and sustain the NO_x reduction reaction, limitation due to the boiler design, and the lack of demonstrated implementation of SNCR for a similar boiler. APC proposes low- NO_x burner, GCP, and a NO_x emission rate of 0.011 lb/MMBtu for BACT.

A review of the RBLC revealed that the proposed control design would provide NO_X control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for NO_X emissions from the Auxiliary Boiler.

Diesel Emergency Engines

Engine design, combustion controls, and GCP were identified as being applicable to diesel engines for the control of NO_x emissions. All these options are considered technically and economically feasible. APC proposes the use of engine design, combustion controls, and GCP with a NMHC + NO_X limit of 4.8 g/bhp-hr for the generators a limit of 3.0 g/bhp-hr for the fire pump as BACT for the emergency engines.

A review of the RBLC revealed that the proposed control design would provide NO_X control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for NO_X emissions from the emergency engines.

SO_2

SO_2 emissions from combustion sources occur as a result of the oxidation of sulfur-containing compounds in the fuel during combustion. SO_2 emissions are typically very low when the fuel contains low concentrations of sulfur compounds. Natural gas and low-sulfur diesel both contain low levels of sulfur compounds and would therefore produce low levels of SO_2 emissions as a result of their combustion.

Clean fuels, good combustion practices, and flue gas desulfurization (FGD) were identified as potential control technologies for the proposed sources.

NGCC Units

A review of RBLC was performed to identify large NGCC units with BACT determinations for SO_2. All listings identified in RBLC describe the use of natural gas or clean fuel as the control technology representative of BACT for this type of unit. Some listings also identified GCP or efficient combustion as BACT. FGD is a control technology utilized to control SO_2 from certain combustion sources. However, FGR control technology has not been demonstrated on natural gas-fired combined cycle units, and since natural gas has a low sulfur content, reductions in SO_2 emissions would be expected to be minimal from the use of FGD technology. As such, APC proposes the exclusive firing of natural gas with a sulfur content less than 0.6 gr/100 scf and a SO_2 emission limitation of 0.002 lb/MMBtu and as BACT.

A review of the RBLC revealed that the proposed control design would provide SO_2 control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for SO_2 emissions from the proposed NGCC units.

Auxiliary Boiler

A review of RBLC was performed to identify small natural gas-fired boilers with BACT determinations for SO_2. Most listings identified in RBLC describe the use of natural gas or clean fuel as the control technology representative of BACT for this type of unit. Some listings identified GCP or efficient combustion as BACT. FGD is a control technology utilized to control SO_2 from certain combustion sources. FGD is not technically feasible for small natural gas-fired boilers due to the expected level of SO_2 emissions being minimal, and FGD control technology has not been demonstrated on small natural gas-fired boilers. As such, APC proposes the exclusive firing of natural gas with a SO_2 emission limitation of 0.002 lb/MMBtu as BACT.

A review of the RBLC revealed that the proposed control design would provide SO_2 control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for SO_2 emissions from the proposed auxiliary boiler.

Emergency Engines

Low sulfur fuel was identified as being applicable to diesel engines for the control of SO_2 emissions. As this was the only control technology identified, APC proposes the use of ultra-low sulfur diesel fuel (containing no more than 15 ppm sulfur) exclusively as BACT.

A review of the RBLC revealed that the proposed control design would provide SO_2 control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for SO_2 emissions from the emergency engines.

VOC

New combustion sources associated with the proposed project would result in VOC emissions as a product of combustion. VOC emissions result from incomplete combustion of carbon compounds in the fuel, which is influenced by the temperature and residence time within the combustion zone.

Combustion controls/good combustion practices, clean fuels, and oxidation catalyst were identified as available control technologies for the control of VOC emissions.

NGCC Units

Potential control technologies for VOC emissions resulting from the NGCC units would be GCP and the use of oxidation catalysts. Both GCP and oxidation catalysts would be considered technically and economically feasible. Oxidation catalysts would be considered top-level control for VOC emissions. APC proposes GCP, oxidation catalysts, and VOC emissions limits of 13.6 lb/hr and 0.003 lb/MMBtu as BACT.

A review of the RBLC revealed that the proposed control design would provide VOC control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for VOC emissions from the proposed NGCC units.

Auxiliary Boiler

GCP, burner design, and oxidation catalysts were identified as potential control alternatives for VOC emissions from small natural gas-fired boilers. Oxidation catalysts must be installed and operated under specific conditions to be effective; since this unit would be expected to operate for short periods of time (typically for up to a few hours at a time prior to startup of the combined cycle units) the unit would not consistently have the appropriate exhaust gas temperature necessary for effective application of an oxidation catalyst. Therefore, GCP and burner design are the only options considered technically and economically feasible. GCP is typically identified as periodic burner tune-ups, maintaining optimum combustion efficiency, and implementing appropriate maintenance procedures. APC proposes GCP, burner design, and a VOC emissions limit of 0.004 lb/MMBtu as BACT.

A review of the RBLC revealed that the proposed control design would provide VOC control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for VOC emissions from the proposed auxiliary boiler.

Emergency Engines

Engine design, combustion controls, and GCP were identified as being applicable to diesel engines for the control of VOC emissions. All these options are considered technically and economically feasible. APC proposes the use of engine design, combustion controls, and GCP with a NMHC + NO_X limit of 4.8 g/bhp-hr for the generators a limit of 3.0 g/bhp-hr for the fire pump as BACT for the emergency engines.

A review of the RBLC revealed that the proposed control design would provide VOC control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for VOC emissions from the proposed emergency engines.

CO

CO emissions result from incomplete combustion of carbonaceous fuels. Temperature and residence time are the primary factors influencing CO formation. The CO emissions from new sources associated with the proposed project are a result of the combustion of natural gas in the NGCC units and auxiliary boiler and diesel fuel in the emergency engines.

Oxidation catalysts, combustion controls/GCP, clean fuels, and engine design were identified as potential control techniques for the control of CO emissions.

NGCC Units

Both oxidation catalysts and combustion controls have been demonstrated on similar sources in the RBLC database and would be considered technically feasible options. The use of oxidation catalysts would be considered the top-level CO control for the NGCC units. APC proposes to use oxidation catalysts and CO emissions limitations of 23.8 lb/hr and 0.005 lb/MMBtu.

A review of the RBLC revealed that the proposed control design would provide CO control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for CO emissions from the proposed NGCC units.

Auxiliary Boiler

GCP, burner design, and oxidation catalysts were identified as a potential control alternative for CO emissions from small natural gas-fired boilers. Oxidation catalysts must be installed and operated under specific conditions to be effective; since this unit would be expected to operate for short periods of time (typically for up to a few hours at a time prior to startup of the combined cycle units) the unit would not consistently have the appropriate exhaust gas temperature necessary for effective application of an oxidation catalyst. Therefore, GCP and burner design are the only options considered technically and economically feasible. GCP is typically identified as periodic burner tune-ups, maintaining optimum combustion efficiency, and implementing appropriate maintenance procedures. APC proposes GCP, burner design, and a CO emissions limit of 0.037 lb/MMBtu as BACT.

A review of the RBLC revealed that the proposed control design would provide CO control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for CO emissions from the proposed auxiliary boiler.

Emergency Engines

Engine design, combustion controls, and GCP were identified as being applicable to diesel engines for the control of CO emissions. All these options are considered technically and economically feasible. APC proposes the use of engine design, combustion controls, and GCP with a CO limit of 2.6 g/bhp-hr as BACT for the emergency engines.

A review of the RBLC revealed that the proposed control design would provide CO control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for CO emissions from the emergency engines.

PM, PM_{10}, $PM_{2.5}$

Particulate matter emissions from combustion sources are a combination of filterable and condensable particles. The filterable portion is the result of incomplete combustion and impurities in the fuel, while the condensable portion is the result of formation of sulfates and other compounds. PM emissions from the cooling tower are emitted as a result of the discharge of liquid water droplets containing dissolved solids in the air steam leaving the unit (called “drift”).

Electrostatic precipitators (ESP), baghouses, clean fuels, GCP/combustion control, boiler design, and engine design were identified as potential control technologies for PM emissions from combustion sources.

NGCC units

There are no add-on controls such as an ESP or Baghouse for PM demonstrated on NGCC units. The top-level demonstrated PM control method for NGCC units is the use of low ash and low sulfur fuels. Firing of natural gas and proper combustion practices are demonstrated on similar units according to the RBLC and would be considered technically and economically feasible. APC proposes to the use of natural gas and good combustion practices with PM emissions limits of 21.51 lb/hr and 0.004 lb/MMBtu (including filterable and condensable PM) as BACT.

A review of the RBLC revealed that the proposed control design would provide PM control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for PM emissions from the proposed NGCC units.

Auxiliary Boiler

A review of RBLC was conducted to determine applicable PM control methods for natural gas-fired boilers less than 100 MMBtu/hr. The use of clean fuels, boiler design, and combustion control were identified as potential controls for PM emissions. Firing of clean fuels, boiler design, and proper combustion practices are demonstrated on similar units according to the RBLC and would be considered technically and economically feasible. APC proposes the firing of clean fuel, combustion control, and boiler design with a PM emissions limit of 0.0075 lb/MMBtu of PM_{10} or $PM_{2.5}$ (filterable) as BACT.

A review of the RBLC revealed that the proposed control design would provide PM control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for PM emissions from the proposed boiler.

Emergency Engines

Engine design, combustion controls, and combustion of clean fuels were identified as being applicable to diesel engines for the control of PM emissions. All of these would be considered technically and economically feasible options. APC proposes engine design, combustion control, combustion of clean fuels, and a PM (filterable) emission limit of 0.15 g/bhp-hr as BACT.

A review of the RBLC revealed that the proposed control design would provide PM control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for PM emissions from the emergency engines.

Cooling Towers

A review of RBLC identified drift eliminators as being an applicable control for PM from cooling towers. Drift eliminators would be technically and economically feasible. APC proposes the use of drift eliminators with a maximum drift rate of 0.0005% of the recirculated water flow as BACT.

A review of the RBLC revealed that the proposed control design would provide PM control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for PM emissions from the cooling towers.

GHG (CO_{2e})

GHG emissions result from the combustion of fuels and include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

Carbon capture, utilization, and storage (CCUS), energy efficient design, low carbon fuels, and GCP were identified as available technologies to control GHG emissions.

NGCC Units

99.9% of GHG emissions from this unit would be CO_2. APC evaluated energy efficiency, use of low carbon fuels, and CCUS as CO_2 emission controls. Energy efficiency and low carbon fuels are considered technically feasible. APC evaluated technical feasibility for CCUS and determined that, 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. However, APC still evaluated the economic feasibility of CCUS for the NGCC. APC determined that the cost for CCUS would be approximately \$73/ton CO_2 captured, equating to an annual cost of \$322 million when considering the size of the units. The levelized cost of electricity from NGCC generation is projected at $183-240 million per year, making CCUS economically infeasible. APC proposes the use of combined cycle technology; CT energy efficiency designs, practices, and procedures; HRSG energy efficiency designs, practices, and procedures; the use of natural gas; and emissions limitations of 2,445,022 tpy CO_{2e} per NGCC unit and 1,000 lb CO_2/MWh-gross as BACT.

A review of the RBLC revealed that the proposed control design would provide GHG control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for GHG emissions from the proposed NGCC units.

Auxiliary Boiler

A review of RBLC was conducted to determine applicable GHG control methods for natural gas-fired boilers less than 100 MMBtu/hr. The use of clean fuels, efficient boiler design, and GCP were identified as potential controls for GHG emissions. Firing of clean fuels, efficient boiler design, and GCP are demonstrated on similar units according to the RBLC and would be considered technically and economically feasible. APC proposes to the firing of clean fuels, efficient boiler design, and GCP with a GHG emissions limitation of 46,416 tons/year as BACT.

A review of the RBLC revealed that the proposed control design would provide GHG control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for GHG emissions from the proposed boiler.

Emergency Engines

Low carbon fuels and GCP were identified as being applicable to diesel engines for the control of GHG emissions. As the only technically feasible option to control GHG emissions from the proposed diesel-fired engines, APC proposes GCP and maintaining the engines according to the manufacturers specifications as BACT.

A review of the RBLC revealed that the proposed control design would provide GHG control that is at least as stringent as most of the other BACT determinations for similar sources. Therefore, the proposed control design listed above is considered BACT for GHG emissions from the emergency engines.

Air Quality Analysis

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new sources or modification. The main purpose of the air quality analysis is to demonstrate that new emissions from a proposed major stationary source or major modification will not cause or contribute to a violation of any applicable National Ambient Air Quality Standards (NAAQS) or PSD increment. Generally the analysis will include (1) an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

National Ambient Air Quality Standards (NAAQS)

The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere. There are no established NAAQS for GHG and VOC. The following table presents the applicable standards for the pollutants under PSD review:

Pollutant/Averaging Time	Primary Standard	Secondary Standard
Nitrogen Dioxide		
NO_2, annual	53 ppb	53 ppb
NO_2, 1-hour	100 ppb	---
Carbon Monoxide		
CO, 8-hour	9 ppm	---
CO, 1-hour	35 ppm	---
Ozone		
O_3, 8-hour	0.070 ppm	0.070 ppm
Sulfur Dioxide		
SO_2, 1-hour	75 ppb	---
SO_2, 3-hour	---	0.5 ppm
Particulate Matter		
PM_{10}, 24-hour	150 $\mu g/m^3$	150 $\mu g/m^3$
$PM_{2.5}$, annual	12.0 $\mu g/m^3$	15.0 $\mu g/m^3$
$PM_{2.5}$, 24-hour	35 $\mu g/m^3$	35 $\mu g/m^3$

A complete review of the air quality analysis can be found in Attachment 1. As can be seen from the review, all of the predicted pollutant concentrations are less than the NAAQS, and the NAAQS for each pollutant are not expected to be exceeded.

PSD Increment

PSD increment is the maximum allowable increase in concentration that can occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. The air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

The PSD requirements provide for a system of area classifications which affords an opportunity to identify local land use goals. There are three area classifications. Each classification differs in terms of the amount of growth it would permit before significant air quality deterioration would be deemed to occur. Class I areas have the smallest increments and thus allow only a small degree of air quality deterioration. Class II areas can accommodate normal well-managed industrial growth. Class III areas have the largest increments and thereby provide for larger amount of development than either Class I or Class II areas. Presently, there are no Class III areas in Alabama. The table below shows the pollutants and associated Class I and II PSD increments.

Pollutant	Averaging Period	Class I (μg/m^3)	Class II (μg/m^3)
NO_2	Annual	2.5	25
	1-hour	---	---
CO	8-hour	---	---
	1-hour	---	---
SO_2	Annual	2	20
	24-hour	5	91
	3-hour	25	512
	1-hour	---	---

PM_{10}	Annual	4	17
	24-hour	8	30
$PM_{2.5}$	Annual	1	4
	24-hour	2	9

The following is a brief synopsis of each class area and how it relates to this project.

<u>Class I Areas:</u>

Class I Areas have the smallest increments and thus allow only a small degree of air quality deterioration. Air Permit applications forms submitted document that the closest Class I Area, the Breton Wildlife Refuge, is not within 100 km from the facility. Therefore, a Class I increment analysis was not required by the Department.

<u>Class II Areas:</u>

Class II areas can accommodate normal well-managed industrial growth. APC – Barry is located in a Class II Area. Attachment No. 1 provides a review of the PSD Class II increment analysis. As can be seen from the review, there are no predicted violations of the Class II increment for any averaging period.

<u>Class III Areas:</u>

Class III areas have the largest increments and thereby provide for larger amount of development than either Class I or Class II areas. Presently, there are no Class III areas in the state of Alabama. Therefore, no Class III area analysis was performed for this project.

<u>Additional Impact Analysis</u>

All PSD permit applicants must prepare an additional impact analysis, for each pollutant subject to regulation, which would be emitted by the proposed new source or modification. This analysis assesses the impacts of air, ground, and water pollution on soils, vegetation, and visibility caused by an increase in emissions and from associated growth. The additional impact analysis generally has three parts:

(a) Growth
(b) Soils and Vegetation
(c) Visibility Impairment

(a) Growth

The facility is an existing source, and APC's proposed project would not be expected to contribute to significant growth at the facility. Commercial growth is not anticipated to occur at an increased rate in the future as a result of the project.

(b) Soils and Vegetation

As the impacts from the proposed project will be less than all NAAQS, which are intended to protect human health and are more stringent than standards intended to protect soil or vegetation, the project is not expected to have a significant impact on the surrounding soil. Modeled impacts of CO and annual NO_2 are less than the SIL. In summary, the project is not expected to result in significant impact on soil, vegetation, or wildlife in the area surrounding the facility.

(c) Visibility Impairment

The PSD regulations require that an analysis be performed to assess the impact from the proposed source on visibility relative to any Class I areas. Since there is no Class I Area located within 100 km of the Barry facility, a Class I ambient air quality impact analysis was not required.

Compliance Assurance Monitoring (CAM)

Each new emissions unit was evaluated for CAM applicability. In order to be subject to CAM a unit must be subject to an emissions limit or standards, use a control device to meet that limit or standard, and have pre-controlled emissions greater than the major source threshold.

There is no add-on control device associated with the units listed below. Therefore, these units would not be subject to CAM.

- 1,500 kW Emergency Generator Engines
- 316 bhp Emergency Fire Pump Engine
- Cooling Towers
- 90.5 MMBtu/hr Auxiliary Boiler (The LNB would not be considered a control device according to the definition in 40 CFR §64.1 since it is considered a passive control measure that acts to prevent pollutants from forming.)

NGCC Units

These units would have non-exempt NO_x emissions limits, use an SCR control device to meet the applicable limits, and pre-controlled NO_X emissions would be greater than the major source threshold of 100 TPY. Therefore, these units would be subject to CAM for NO_x emissions.
Proposed Monitoring: NO_x CEMS is required by 40 CFR Part 60, Subpart KKKK. This would be considered presumptively acceptable monitoring to satisfy CAM requirements.

These units would have non-exempt CO and VOC emissions limits, use an oxidation catalyst to meet the applicable limits, and pre-controlled CO and VOC emissions would be greater than the major source threshold of 100 TPY. Therefore, these units would be subject to CAM for CO and VOC emissions.

Proposed Monitoring: The oxidation catalyst inlet temperature will be monitored continuously to ensure the minimum temperature for effective CO and VOC control is maintained.

These units are subject to non-exempt emissions limits for PM and SO_2 but would not use a control device to meet those limits. Therefore, CAM would not be applicable for those pollutants.

The information required under 40 CFR §64.4 shall be submitted along with the Title V renewal application update that must be submitted within 1 year of startup of the proposed units or as a part of an application for renewal, whichever is sooner. <u>40 CFR 64.5(a)(2) and (3)</u>

<u>40 CFR Part 60 (NSPS)</u>

<u>40 CFR Part 60, Subpart A – General Provisions</u>

The proposed project sources would be subject to various 40 CFR Part 60 subparts. As a result, these sources would be required to comply with applicable requirements of this subpart.

<u>40 CFR Part 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units</u>

This rule applies to steam generating units for which construction, modification, or reconstruction is commenced after June 19, 1984 and that has a max design heat input capacity greater than 100 MMBtu/hr. The proposed NGCC unit's duct burners would have a heat input capacity greater than 100 MMBtu/hr. However, the NGCC units are subject to 40 CFR Part 60, Subpart KKKK. According to 40 CFR 60.4305(b), heat recovery steam generators and duct burners regulated under subpart KKKK are exempted from the requirements of subparts Da, Db, and Dc of 40 CFR Part 60. The proposed auxiliary boiler would be rated below the 100 MMBtu/hr threshold and would not be subject to this subpart.

40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

This rule applies to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a max design heat input capacity between 100 and 10 MMBtu/hr. The proposed 90.5 MMBtu/hr auxiliary boiler would be subject to the monitoring, recordkeeping, and reporting requirements of this subpart. The duct burners associated with the NGCC units would have a capacity above 100 MMBtu/hr and would not be subject to this subpart.

40 CFR Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels

This rule applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. The fuel storage tank associated with the emergency engine would not be subject to this subpart since the storage capacity would be less than 75 m^3.

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

As new engines, the proposed diesel emergency generator and firewater pump engines would be subject to this subpart. The permittee must purchase engines certified to the applicable emission standards. Emission limits proposed as a part of BACT are at least as stringent as the emission limits contained in this subpart.

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

The NGCC unit would be subject to 40 CFR Part 60, Subpart KKKK. The HRSG, including the duct burner associated with the turbine, would also be subject to the emission limits under Subpart KKKK. The new unit would be subject to the applicable emission limits, monitoring, recordkeeping, and reporting requirements of this subpart. Emission limits proposed as a part of BACT would be at least as stringent as the emission limits contained in this subpart.

40 CFR Part 60, Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units

The new combustion turbines would be subject to this subpart to include the CO_2 emissions limitation. Stationary turbines that burn natural gas are not subject to any monitoring or reporting requirements under this subpart [40 CFR §60.5520(d)(1)]. Emission limits proposed as a part of BACT would be at least as stringent as the emission limits contained in this subpart.

40 CFR Part 63 (NESHAP/MACT)

40 CFR Part 63, Subpart A

The proposed project sources would be subject to various 40 CFR Part 63 subparts. As a result, these sources would be required to comply with applicable requirements of this subpart.

40 CFR Part 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

This subpart is applicable to the proposed NGCC units. EPA issued a stay on the effectiveness of this rule's requirements pertaining to lean premix gas-fired combustion turbines and new diffusion flame gas-fired turbines on August 18, 2004. The proposed NGCC units would be considered lean premix gas-fired combustion turbines. As a result, the NGCC units would be covered by the August 18, 2004 stay. As long as the stay is in place, these units would be subject to the initial notification requirements in 40 CFR 63.6145. If the stay is lifted, the units would become subject to a formaldehyde emission limit of 91 ppbvd @ 15% O_2.

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

The proposed emergency engines would be subject to this subpart. These units would meet the requirements of this subpart by meeting the requirements of 40 CFR Part 60, Subpart IIII.

40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boiler and Process Heaters

This rule would apply to the auxiliary boiler included in the proposed project. This unit would be considered a unit designed to burn gas 1 fuels. As a result, there are no emissions or operating limits for this unit under this subpart. This unit would be required to conduct a one-time energy assessment and tune-ups in accordance with MACT DDDDD. This unit would also be subject to the applicable notification, recordkeeping, and reporting requirements under this subpart.

<u>40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units</u>

This subpart does not apply to electric generating units that only burn natural gas as the proposed NGCC units will.

ADEM Admin. Code r. 335-3

<u>Opacity</u>

ADEM Admin. Code r. 335-3-4-.01 states that no person shall discharge from any source of emission, particulate of an opacity greater than twenty percent (20%), as determined by a six (6) minute average. ADEM 335-4-.01(b) states that during one six (6) minute period in any sixty (60) minute period a person may discharge into the atmosphere from any source of emissions, particulate of an opacity not greater than that designated as forty percent (40%) opacity. The proposed unit would be subject to this rule and would be expect the meet the applicable opacity requirements.

<u>Particulate Matter (PM)</u>

The boiler and NGCC units would be subject to a PM emission limit according to Table 4-1 of ADEM Admin. Code r. 335-3-4-.03. Emissions from the units would be expected to be well below the allowable emission rate since natural gas would be the only fuel source.

<u>Sulfur Dioxide (SO_2)</u>

ADEM Admin. Code r. 335-3-5-.01(1)(b) assigns the proposed boiler and NGCC units an allowable sulfur dioxide emission rate of 1.8 lb/MMBtu since the units would be located in a Category I county. Emissions from the units would be expected to be below the allowable emission rate since natural gas would be the only fuel source. In addition, these units are subject to more stringent BACT standards for SO_2.

<u>Nitrogen Oxides (NOx)</u>

ADEM Admin. Code r. 335-3-8-.06 assigns the proposed combined-cycle units a NOx limit of 4.0 ppmvd at 15% O_2. This unit would be equipped with a Selective Catalytic Reduction (SCR) system for NOx control and would be expected to meet this limitation.

Recommendation

Based on the above analysis, I recommend that, upon receiving permitting fees and pending the completion of the appropriate public comment period, the following Air Permits be issued with the attached provisos (See Attachment 2):

503-1001-X013	Unit 8 Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and Selective Catalytic Reduction (SCR) Unit 9 Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and Selective Catalytic Reduction (SCR)
503-1001-X014	Natural Gas-Fired Auxiliary Boiler (90.5 MMBtu/hr) Cooling Towers
503-1001-X015	Unit 8 Emergency Generator (1,500 kW) Unit 9 Emergency Generator (1,500 kW) Firewater Pump Engine (236 kW)

Tyler Phillips
Tyler Phillips
Industrial Minerals Section
Energy Branch
Air Division

Date: May 20, 2020

ATTACHMENT NO. 1

Air Quality Analysis

LANCE R. LEFLEUR
DIRECTOR

1

KAY IVEY
GOVERNOR

Alabama Department of Environmental Management
adem.alabama.gov

1400 Coliseum Blvd. 36110-2400 ▪ Post Office Box 301463
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(334) 271-7700 ▪ FAX (334) 271-7950

March 27, 2020

MEMORANDUM

TO: Tyler Phillips TSP
Industrial Minerals Section
Energy Branch
Air Division

FROM: Geoffrey Healan G/gx
Meteorological Section
Planning Branch
Air Division

SUBJECT: Air Dispersion Modeling for Alabama Power Company – Plant Barry – Unit 8-9 Prevention of Significant Deterioration Permit Application

ADEM has completed its review of an air quality modeling analysis performed by the Alabama Power Company for the construction of units 8-9 at Plant Barry. The purpose of the analysis was to assess the impacts on air quality from emissions of particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), Carbon Monoxide (CO) and Nitrogen Dioxide (NOx) from a modification at the facility located in Mobile County, Alabama. An air quality analysis was performed for these pollutants to demonstrate that emissions from the modification will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD Increment.

AIR QUALITY MODELS:

The most recent version of the AERMOD model and associated processors were used in default mode when performing modeling for all pollutants.

METEOROLOGICAL DATA:

The most recent 5 years (2014-2018) of surface and upper air meteorological data from the closest National Weather Service (NWS) office was used. Surface data from Mobile, Alabama and upper air data from Slidell, Louisiana were used in the analysis.

GOOD ENGINEERING PRACTICE ANALYSIS:

A Good Engineering Practice (GEP) Analysis was performed to assess possible building downwash effects. It was determined that the stack modeled will be within 5L (the influence area) of one or more of the controlling buildings. Building downwash was considered for those sources in the modeling.

SCREENING MODELING

The sources affected by this expansion are shown below. Table 1 lists the stack parameters and emission rates used in the modeling.

TABLE 1

Stack Parameters

Units 8-9

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)		163	180	178	169	165
Exit Velocity (ft/sec)		63.26	64.11	58.87	52.29	44.04
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

*Inlet Conditioning, Duct Burning

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

The receptor grid consisted of a Cartesian grid and discrete receptors placed along the facility fence line at 100 meter intervals. The Cartesian grid extends approximately 22.5 km, from the center of the Barry Plant, in all directions. Receptor spacing is as follows: 100 meter spacing out to 4.8 kilometers, 250 meter spacing from 4.8 to 6.8 kilometers, 500 meter spacing from 6.8 to 7.5 kilometers, 1000 meter spacing from 7.5 to 12 kilometers, and 2000 meter spacing from 12 to 22.5 kilometers. All maximum concentrations were resolved to within 100 meter spacing.

Receptor terrain elevations were developed from the USGS digital elevation model (DEM) using data from the one third arc second resolution map. Table 2 lists the results of screening modeling performed for SO_2, PM_{10}, $PM_{2.5}$, NO_2 and CO using all five years of meteorological data at individual worst case load scenarios.

TABLE 2

SIL Modeling

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
$PM_{2.5}$	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

*Draft SIL

REFINED MODELING:

NAAQS Analysis:

Since impacts for 1-hour NO_2 and 24-hour and Annual $PM_{2.5}$ were above the significance levels, refined modeling was required. These analyses included all emission sources at Barry as well as an inventory of other nearby sources. Results of the refined analysis showed that impacts associated with 1 hour NO_2, 24-hour and annual $PM_{2.5}$ concentrations fall below the respective NAAQS and PSD Increments. Results of the modeling are shown in Tables 3 and 4.

TABLE 3

NAAQS Modeling Results

Pollutant	Averaging Period	Rank	Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	MERP	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Complies (Y/N)?
NO_2	1-hour	98th Percentile Peak Daily 1-hr 5-year Average	85.84	31.0	NA	116.84	189	Yes
$PM_{2.5}$	24-hour	98th Percentile 24-hr 5-year Average	11.51	17.0	.092	28.60	35	Yes
	Annual	5-year Average	2.12	8.1	.002	10.22	12	Yes

TABLE 4

PSD Increment Modeling Results

Pollutant	Averaging Period	Rank	Modeled Concentration ($\mu g/m^3$)	PSD Increments ($\mu g/m^3$)	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

MERPs ANALYSIS:

Precursor emission impacts to Ozone and $PM_{2.5}$ (secondary $PM_{2.5}$) were considered and a Modeled Emission Rates for Precursors (MERPs) analysis was performed for this application. The Ozone precursors include the pollutants VOC and NO_x, and the precursor emissions of interest for secondary $PM_{2.5}$ are NO_x and SO_2. The results for the MERPs analyses are presented in Table 5. The details of the analysis can be found in the application.

TABLE 5
MERPs Analysis Results
Secondary PM

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

These secondary PM2.5 concentrations were added to Project direct modeled PM2.5 (using AERMOD) to estimate total Project concentrations for both the SIL and NAAQS/PSD increment analyses, as applicable. The Project secondary PM2.5 concentrations are calculated in Table 5. These concentrations are added to modeled AERMOD concentrations in Table 3 to demonstrate compliance with the NAAQS and PSD increments as applicable for PM2.5.

TABLE 6
MERPs Analysis Results
Ozone

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

The three year (2016-2018) 8-hour ozone NAAQS design value for Chickasaw is 64 ppb based on design value summaries from EPA. The Project estimated ozone concentration (from Table 6) of 1.74 ppb is added to the 64 ppb design value resulting 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.

CONCLUSION:

In conclusion, emissions of SO_2, PM_{10}, $PM_{2.5}$, NOX and CO from the proposed Plant Barry project in Mobile County, Alabama, are not expected to cause or contribute to any violation of the NAAQS or PSD Increments.

ATTACHMENT NO. 2

Proposed Permit Provisos

AIR PERMIT

PERMITTEE: ALABAMA POWER COMPANY

FACILITY NAME: BARRY STEAM ELECTRIC GENERATING PLANT

LOCATION: BUCKS, MOBILE COUNTY, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE, OR DEVICE
503-1001-X014	Unit 8 Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and Selective Catalytic Reduction (SCR)
	Unit 9 Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and Selective Catalytic Reduction (SCR)

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, Ala. Code §§ 22-28-1 to 22-28-23, as amended, the Alabama Environmental Management Act, Ala. Code §§ 22-22A-1 to 22-22A-17, as amended, and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: TBD

Alabama Department of Environmental Management

General Permit Provisos

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission, which requires testing, will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. Unless otherwise specified in the unit-specific provisos of this permit, in case of shutdown of air pollution control equipment (which operates pursuant to this permit) for scheduled maintenance for a period greater than **1 hour,** the intent to shut down shall be reported to the Air Division at least 24 hours prior to the planned shutdown, **unless accompanied by the immediate shutdown of the emission source.**

6. Unless otherwise specified in the unit-specific provisos of this permit, in the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants which are above an applicable standard, the person responsible for such equipment shall notify the Air Division within an additional 24 hours or the next working day and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. All deviations from the requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regard to the date, time, duration, cause, and corrective actions taken to bring the source(s) back into compliance.

8. Unless otherwise specified, this process, including all air pollution control devices and capture systems for which this permit is issued shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

9. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

10. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

11. Prior to a date to be specified by the Chief of the Air Division in the authorization to operate, emission tests are to be conducted by persons familiar with and using the EPA Sampling Train and Test Procedure as described in the Code of Federal Regulations, Title 40, Part 60, for the following pollutants. Written tests results are to be reported to the Air Division within 30 working days of completion of testing.

Particulates	(X)	Carbon Monoxide	(X)
Sulfur Dioxide	(X)	Nitrogen Oxides	(X)
Volatile Organic Compounds	(X)	Visible Emissions	( )

12. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

13. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

14. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

15. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

16. The Air Division must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

    To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

    a. The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

    b. A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

    c. A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

d. A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

All test reports must be submitted to the Air Division within 30 days of the actual completion of the test, unless an extension of time is specifically approved by the Air Division.

17. Records will be maintained of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the process equipment and any malfunction of the air pollution control equipment. These records will be kept in a permanent form suitable for inspection and will be retained for at least two years following the date of each occurrence.

18. Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.

    Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:

    a. by the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;

    b. by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

    c. by paving;

    d. by the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;

    Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.

19. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3) approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

20. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

21. The issuance of this permit does not convey any property rights of any sort, or any exclusive

privilege.

22. The permittee shall keep this permit under file or on display at all times at the site where the facility for which the permit is issued is located and shall make the permit readily available for inspection by any or all persons who may request to see it.

23. An annual compliance certification shall be submitted by November 30, covering the reporting period of October 1 through September 30 of the previous calendar year, unless more frequent periods are specified according to the specific rule governing the source or required by the Department.

    (a) The compliance certification shall include the following:

    a. The identification of each term or condition of this permit that is the basis of the certification;

    b. The compliance status;

    c. The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);

    d. Whether compliance has been continuous or intermittent; and

    e. Such other facts as the Department may require in order to determine the compliance status of the source.

    (b) The compliance certification shall be submitted to:

Alabama Department of Environmental Management
Air Division
P.O. Box 301463
Montgomery, AL 36130-1463

Unit 8 and Unit 9 Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and SCR Provisos

	Regulations
Applicability	
1. These units are part of a source subject to the applicable requirements of ADEM Admin. Code r. 335-3-16, "Major Source Operating Permits".	Rule 335-3-16-.03
2. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01, "Control of Particulate Emissions – Visible Emissions".	Rule 335-3-4-.01
3. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.03, "Control of Particulate Emissions – Fuel Burning Equipment".	Rule 335-3-4-.03
4. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-5-.01, "Control of Sulfur Compound Emissions – Fuel Combustion".	Rule 335-3-5-.01
5. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-8-.06, "Control of Nitrogen Oxide Emissions – Standards for New Combined-Cycle Electric Generating Units".	Rule 335-3-8-.06
6. These units have limits in accordance with the applicable requirements of ADEM Admin. Code r. 335-3-14-.04, "Air Permits Authorizing Construction in Clean Air Areas [Prevention of Significant Deterioration]".	Rule 335-3-14-.04 (BACT)
7. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines".	Rule 335-3-10-.02(89) 40 CFR §60.4305(a)
8. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart TTTT, "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units".	Rule 335-3-10-.02(96) 40 CFR §60.5509(a)(1)
9. These units are subject to the applicable requirements of 40 CFR Part 63, Subpart YYYY, "National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines".	Rule 335-3-11-.06(103) 40 CFR §63.6085
10. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart A, "General Provisions".	Rule 335-3-10-.02(1) 40 CFR §60.1(a)

	Regulations
	40 CFR §60.5570
11. These units are subject to the Acid Rain Rules contained in ADEM Admin. Code r. 335-3-18 and 40 CFR Parts 72, 73, and 75.	Rule 335-3-18 40 CFR Parts 72, 73, 75
12. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions are incorporated as enforceable conditions of this permit.	Rule 335-3-16-.05(a)2.
13. These units are subject to the applicable provisions of the Cross-State Air Pollution Rule found in ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36 and ADEM Admin. Code r. 335-3-8-.07 through 335-3-8-.70.	Rules 335-3-5-.06 through 335-3-5-.36 and Rules 335-3-8-.07 through 335-3-8-.70
14. These units are subject to the applicable provisions of 40 CFR Part 98, "Mandatory Greenhouse Gas Reporting."	40 CFR Part 98
Emission Standards	
1. The sulfur dioxide (SO_2) emission rate from these units shall not exceed 1.8 lb/MMBtu.	Rule 335-3-5-.01(1)(a)
2. Particulate matter (PM) emissions from these units shall not exceed 0.12 lb/MMBtu per Table 4-1 of ADEM Admin. Code r. 335-3-4-.03.	Rule 335-3-4-.03(1)
3. The nitrogen oxide (NO_X) emission rate from these units shall not exceed 4.0 ppmvd at 15% O_2.	Rule 335-3-8-.06(3)
4. Visible emissions from these units shall not exceed 20% opacity except during one six (6) minute period in any sixty (60) minute period which opacity shall not exceed 40%.	Rule 335-3-4-.01(1)
5. The NO_X emission rate from these units shall not exceed 15 ppm (at 15% O_2) or 0.43 lb/MWh of useful output. These limits apply on a 30-day rolling average basis.	Rule 335-3-10-.02(89) 40 CFR §60.4320(a) Subpart KKKK, Table 1
6. The permittee must not burn any fuel in the turbines which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb/MMBtu) heat input.	Rule 335-3-10-.02(89) 40 CFR §60.4330(a)(2)

	Regulations
7. The carbon dioxide (CO_2) emission rate from the combined-cycle units shall not exceed 1,000 lb CO_2/MWh of gross energy output (450 kg CO_2/MWh). Compliance is determined on a 12-month rolling average basis.	Rule 335-3-10-.02(96) 40 CFR §60.5520(a) Subpart TTTT, Table 2 Rule 335-3-14-.04 (BACT)
8. The carbon dioxide equivalent (CO_{2e}) emission rate from each unit shall not exceed 2,445,022 tons/yr.	Rule 335-3-14-.04 (BACT)
9. The combustion turbines and duct burners shall fire only natural gas.	Rule 335-3-14-.04 (BACT)
10. The sulfur content of the fuel burned in the combined-cycle units shall not exceed 0.6 gr/100 scf.	Rule 335-3-14-.04 (BACT)
11. Emissions exceeding any allowances that the source lawfully holds under Title IV of the Act or the regulations promulgated thereunder are prohibited.	Rule 335-3-16-.05(d)
12. The combustion turbines (CT) and duct burners (DB) are subject to numeric emission limitations and work practice standards (WPS) as specified in Provisos 13 through 18 below.	
13. Except as provided for in Proviso 18 below, the NO_X emission rate from each unit shall not exceed 39.1 lb/hr and 0.008 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
14. Except as provided for in Proviso 18 below, the SO_2 emission rate from each unit shall not exceed 0.002 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
15. Except as provided for in Proviso 18 below, the carbon monoxide (CO) emission rate from each unit shall not exceed 23.8 lb/hr and 0.005 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
16. Except as provided for in Proviso 18 below, the volatile organic compound (VOC) emission rate from each unit shall not exceed 13.6 lb/hr and 0.003 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
17. Except as provided for in Proviso 18 below, particulate matter less than 10 micros (PM_{10}) and particulate matter less than 2.5 micros ($PM_{2.5}$) emissions from each unit shall not exceed 21.51 lb/hr and 0.004 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
18. During periods of startup, shutdown, and load change (as defined in Proviso 19 below), the permittee shall comply with the following work practice standards in lieu of the numeric limitations in Provisos 13-17	Rule 335-3-14-.03(1)(h)

	Regulations
above:	
(a) The permittee shall take all reasonable actions to minimize the magnitude and duration of emissions during the periods listed above.	
(b) Employ good operation and maintenance practices on the Turbines and Duct Burners, including on associated pollution control technology.	
(c) Comply with emissions monitoring, recordkeeping, and reporting requirements in this permit.	
(d) During periods of startup of the CT, the permittee shall, consistent with technological limitations, manufacturers' specifications, and good engineering and maintenance practices for SCR, initiate reagent flow in the SCR once the flue gas reaches the requisite temperature for NOx control.	
(e) During periods of startup of the DB and periods of shutdown of the DB the permittee shall maintain reagent flow in the SCR consistent with technological limitations, manufacturers' specifications, and good engineering and maintenance practices for SCR and so as to minimize NOx emissions to the extent reasonably practicable.	
(f) During periods of shutdown of the CT, the permittee shall, consistent with technological limitations, manufacturers' specifications, and good engineering and maintenance practices for SCR, maintain reagent flow in the SCR until the flue gas temperature falls below the requisite temperature for NOx control.	
19. Startup, shutdown, and load change are defined below:	Rule 335-3-14-.04
(a) Startup – The period from when the combustion turbine is started until it reaches the minimum emissions compliance load (MECL).	
(b) Shutdown – The period when the load on the combustion turbine is decreasing from the MECL for the purpose of shutting down the unit.	
(c) Load Change - A change in heat input that creates a transient operating condition that is readily identifiable on the load chart recording.	
Compliance and Performance Test Methods and Procedures	

	Regulations
1. Compliance with the NO_X emission limitations in Emission Standards Proviso 3 shall be determined by EPA Reference Method 20 as found in 40 CFR Part 60, Appendix A and Proviso 13 shall be determined by EPA Reference Method 7 or 7E as found in 40 CFR Part 60, Appendix A.	Rule 335-3-8-.06(4) Rule 335-3-1-.05(1)
2. Compliance with the NO_x emission limitation in Emission Standards Proviso 5 shall be determined using a NOx diluent CEMS that is installed, operated, maintained, and certified according to 40 CFR Part 75, Appendix A.	Rule 335-3-10-.02(89) 40 CFR §60.4335
3. For purposes of demonstrating compliance with the sulfur content of the fuel pursuant in Proviso 6 of the Emission Standards Section, the owner or operator may use one of the following options:	Rule 335-3-10-.02(89) 40 CFR §60.4360
(a) Analyze the sulfur content of the fuel using ASTM D1072, or alternatively D3246, D4048, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377;	40 CFR §60.4415(a)
(b) Maintain a current, valid fuel purchase contract, tariff sheet, or transportation contract for the natural gas specifying the maximum total sulfur content is less than 20 grains sulfur per 100 scf and has potential sulfur emissions of less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input;	40 CFR §60.4365(a)
(c) Conduct daily sampling of the natural gas sulfur content for the first 30 unit operating days following the change and annually thereafter to show the actual fuel sulfur content is less than 10 grains sulfur per 100 scf; or	40 CFR §60.4370(c)(1)
(d) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.	40 CFR §60.4365(b)
4. Compliance with the CO_2 emissions limitation in Emission Standards Proviso 7 shall be determined using the methods provided in 40 CFR Part 60, Subpart TTTT.	Rule 335-3-10-.02(96) 40 CFR §60.5540
5. Compliance with the SO_2 emissions limitations in Emission Standards Proviso 1 and Proviso 14 shall be determined by EPA Reference Method 6 or 20 as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05(1)
6. Compliance with the opacity standard in Emission Standards Proviso 4 shall be determined by EPA Reference Method 9 of 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05(1)

	Regulations
7. Compliance with the CO emission limitation in Emission Standards Proviso 15 shall be determined by Method 10 of 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05(1)
8. Compliance with the PM emission limitation in Emission Standards Proviso 17 shall be determined by either Method 5, 17, or 201 along with Method 202 of 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05(1)
9. Compliance with the PM emission limitation in Emission Standards Proviso 2 shall be determined by Method 5 or 17 of 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05(1)
10. Compliance with the VOC emission limitation shall be determined by EPA Reference Method 25, 25A, or 25B of 40 CFR Part 60, Appendix A from each combined turbine and duct burner stack.	Rule 335-3-1-.05(1)
11. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3) approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.	Rule 335-3-1-.05(1)
12. The permittee must operate and maintain the stationary combustion turbines, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.	Rule 335-3-10-.02(89) 40 CFR §60.4333
Emission Monitoring	
1. A continuous emissions monitoring system (CEMS) to measure NO_x emissions shall be installed and operated at a location approved by the Director. The CEMS shall meet the specification and procedures of 40 CFR Part 75 and will be certified and maintained in accordance with 40 CFR Part 75.	Rule 335-3-10-.02(89) 40 CFR §60.4345 Rule 335-3-14-.04
2. The oxidation catalyst inlet temperature shall be monitored continuously and maintained above 625°F, based on a 3-hour block average, during periods of normal operation.	Rule 335-3-14-.03(b)
Recordkeeping and Reporting Requirements	
1. An excess emissions report for each combined turbine/duct burner stack will be submitted to the ADEM within thirty days of the end of	Rule 335-3-14-.04

	Regulations
each calendar quarter. The report will contain the following format:	

<u>NOx</u>

A. Source Operating Time (all times and periods in hours)

B. Time Monitoring System was Able to Record Source Performance *

C. Monitor Availability (%) = B/A x 100

D. Total Periods where the CEM data may indicate emissions above the numerical limitation **

E. Overall Source Performance (%) = [(B - D)/B] x 100

F. Number of periods above the numerical limitation during periods subject to work practice standards – F(x) (3-hour periods)

F1 = Startup/Shutdown

F2 = Load Change

G. Net Excess Emissions = D – ∑F(x)

H. Net Source Performance (%) - H(x):

= [1 - (G/(B - ∑F(x))] x 100

= [(B - ∑F(x) - G)/(B - ∑F(x))] x 100

I. Overall Exceedances (%) - Percent of time above the numeric limitations due to all reasons:

= (D/B) x 100

J. Net Exceedances (%) - Percent of time above the numeric limitation during periods subject to the numerical limitation:

= [(B – ∑F(x))/ B] x 100

K. Percent of time above the numeric limitation during periods subject to work practice limitations

SU/SD = (F1/B) x 100

Load Change = (F2/B) x 100

* Information identifying each period during which the monitoring systems were inoperative (except for zero and span checks) and the nature of the system repairs or adjustments will be maintained and made available upon request.

** Report date, time duration, magnitude, cause and corrective action taken for each occurrence. NO_X emissions rate (lb/MMBtu) will be computed as a 3-hour rolling average.

NOTE: Data recorded during periods of system breakdowns, repairs,

	Regulations
adjustments, and calibration checks shall not be included in any of the above data averages.	
2. The Permittee must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.	Rule 335-3-10-.02(89) 40 CFR §60.4375(a)
3. Records of the oxidation catalyst inlet temperature shall be maintained and kept in a form suitable for inspection. The records will be retained for at least two years.	Rule 335-3-14-.04
4. All reports required under §60.7(c) must be postmarked by the 30th day following the end of each calendar quarter.	Rule 335-3-10-.02(89) 40 CFR §60.4395 Rule 335-3-14-.04
5. The facility shall comply with the recordkeeping and reporting requirements of CSAPR found in Rules 335-3-5-.31, 335-3-5-.35, 335-3-8-.33, 335-3-8-.37, 335-3-8-.65, and 335-3-8-.69.	Rules 335-3-5-.31, 335-3-5-.35 Rules 335-3-8-.33, 335-3-8-.37, 335-3-8-.65, 335-3-8-.69

AIR PERMIT

PERMITTEE: ALABAMA POWER COMPANY

FACILITY NAME: BARRY STEAM ELECTRIC GENERATING PLANT

LOCATION: BUCKS, MOBILE COUNTY, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE, OR DEVICE
503-1001-X015	90.5 MMBtu/hr Auxiliary Boiler
	Cooling Towers

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, Ala. Code §§ 22-28-1 to 22-28-23, as amended, the Alabama Environmental Management Act, Ala. Code §§ 22-22A-1 to 22-22A-17, as amended, and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: TBD

____

Alabama Department of Environmental Management

General Permit Provisos

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission, which requires testing, will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. Unless otherwise specified in the unit-specific provisos of this permit, in case of shutdown of air pollution control equipment (which operates pursuant to this permit) for scheduled maintenance for a period greater than **1 hour,** the intent to shut down shall be reported to the Air Division at least 24 hours prior to the planned shutdown, **unless accompanied by the immediate shutdown of the emission source.**

6. Unless otherwise specified in the unit-specific provisos of this permit, in the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants which are above an applicable standard, the person responsible for such equipment shall notify the Air Division within an additional 24 hours or the next working day and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. All deviations from the requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regard to the date, time, duration, cause, and corrective actions taken to bring the source(s) back into compliance.

8. Unless otherwise specified, this process for which this permit is issued shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

9. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

10. On completion of construction of the device(s) for which this permit is issued, written

notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

11. Prior to a date to be specified by the Chief of the Air Division in the authorization to operate, emission tests are to be conducted by persons familiar with and using the EPA Sampling Train and Test Procedure as described in the Code of Federal Regulations, Title 40, Part 60, for the following pollutants. Written tests results are to be reported to the Air Division within 30 working days of completion of testing.

Particulates	(X)	Carbon Monoxide	(X)
Sulfur Dioxide	(X)	Nitrogen Oxides	(X)
Volatile Organic Compounds	(X)	Visible Emissions	( )

X = Auxiliary Boiler

12. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

13. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

14. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

15. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

16. The Air Division must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

    To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

    a. The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

    b. A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

c. A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

d. A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

All test reports must be submitted to the Air Division within 15 days of the actual completion of the test, unless an extension of time is specifically approved by the Air Division.

17. Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.

    Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:

    a. by the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;

    b. by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

    c. by paving;

    d. by the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;

    Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.

18. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3) approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

19. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

20. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

21. The permittee shall keep this permit under file or on display at all times at the site where the facility for which the permit is issued is located and shall make the permit readily available for

inspection by any or all persons who may request to see it.

22. An annual compliance certification shall be submitted by November 30, covering the reporting period of October 1 through September 30 of the previous calendar year, unless more frequent periods are specified according to the specific rule governing the source or required by the Department.

    (a) The compliance certification shall include the following:

        a. The identification of each term or condition of this permit that is the basis of the certification;

        b. The compliance status;

        c. The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);

        d. Whether compliance has been continuous or intermittent; and

        e. Such other facts as the Department may require in order to determine the compliance status of the source.

    (b) The compliance certification shall be submitted to:

Alabama Department of Environmental Management
Air Division
P.O. Box 301463
Montgomery, AL 36130-1463

Auxiliary Boiler and Cooling Towers
Provisos

	Regulations
Applicability	
1. These units are part of a source subject to the applicable requirements of ADEM Admin. Code r. 335-3-16, "Major Source Operating Permits".	Rule 335-3-16-.03
2. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01, "Control of Particulate Emissions – Visible Emissions".	Rule 335-3-4-.01
3. The boiler is subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.03, "Control of Particulate Emissions – Fuel Burning Equipment".	Rule 335-3-4-.03
4. The boiler is subject to the applicable requirements of ADEM Admin. Code r. 335-3-5-.01, "Control of Sulfur Compound Emissions – Fuel Combustion".	Rule 335-3-5-.01
5. These units have limits in accordance with the applicable requirements of ADEM Admin. Code r. 335-3-14-.04, "Air Permits Authorizing Construction in Clean Air Areas [Prevention of Significant Deterioration]".	Rule 335-3-14-.04 (BACT)
6. The boiler is subject to the applicable requirements of 40 CFR Part 63, Subpart DDDDD, "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters".	Rule 335-3-11-.06(107) 40 CFR §63.7485
7. The boiler is subject to the applicable requirements of 40 CFR Part 63, Subpart A, "General Provisions".	Rule 335-3-11-.06(1) 40 CFR §63.1(a)(4)(i) 40 CFR §63.7565
8. The boiler is subject to the applicable requirements of 40 CFR Part 60 Subpar Dc, "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units."	Rule 335-3-10-.02(2)(c) 40 CFR §60.40c(a)
9. The boiler is subject to the applicable requirements of 40 CFR Part 60, Subpart A, "General Provisions".	Rule 335-3-10-.02(1) 40 CFR §60.1(a)
10. The boiler is subject to the applicable provisions of 40 CFR Part 98, "Mandatory Greenhouse Gas Reporting".	40 CFR Part 98

	Regulations
Emission Standards	
1. The permittee shall not discharge to the atmosphere particulate of an opacity greater than 20%, as determined by a six-minute average, except that during one six-minute period in any sixty (60) minute period, the permittee may discharge into the atmosphere particulate of an opacity not greater than 40%.	Rule 335-3-4-.01(1)
2. The nitrogen oxide (NO_X) emission rate from the boiler shall not exceed 0.011 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
3. The sulfur dioxide (SO_2) emission rate from the boiler shall not exceed 0.002 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
4. The carbon monoxide (CO) emission rate from the boiler shall not exceed 0.037 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
5. The volatile organic compound (VOC) emission rate from the boiler shall not exceed 0.004 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
6. Particulate matter less than 10 micros (PM_{10}) and particulate matter less than 2.5 micros ($PM_{2.5}$) emissions from the boiler shall not exceed 0.0075 lb/MMBtu.	Rule 335-3-14-.04 (BACT)
7. The carbon dioxide equivalent (CO_2e) emission rate from the boiler shall not exceed 46,416 tons/yr.	Rule 335-3-14-.04 (BACT)
8. The SO_2 emission rate from the boiler shall not exceed 1.8 lb/MMBtu.	Rule 335-3-5-.01(1)(a)
9. Particulate Matter emissions from the boiler shall not exceed the allowable per Table 4-1 of ADEM Admin. Code r. 335-3-4-.03.	Rule 335-3-4-.03(1)
10. The boiler shall only combust natural gas.	Rule 335-3-14-.04 (BACT)
11. The boiler shall utilize good combustion practices.	Rule 335-3-14-.04 (BACT)
12. The permittee shall conduct an annual tune-up of the boiler unless the unit employ's a continuous oxygen trim system to maintain an optimum air to fuel ratio, in which case the tune up must be performed once every five years. The tune-up shall be conducted as specified in 40 CFR §63.7540.	Rule 335-3-11-.06(107) 40 CFR §63.7500(a)(1)
13. The cooling towers shall be installed with drift eliminators and have a maximum drift of 0.0005% of recirculated water.	Rule 335-3-14-.04 (BACT)

	Regulations
Compliance and Performance Test Methods and Procedures	
1. Compliance with the particulate matter emission standards shall be determined by EPA Reference Method 5 or 17, as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05
2. Compliance with the opacity standard shall be determined by EPA Reference Method 9, as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05
3. Compliance with the NO_X emission standard shall be determined by EPA Reference Method 7 or 7E, as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05
4. Compliance with the VOC emission standard shall be determined by EPA Reference Method 25, 25A, or 25B, as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05
5. Compliance with the CO emission standard shall be determined by EPA Reference Method 10, as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05
6. Compliance with the SO_2 emission standards shall be determined by EPA Reference Method 6, as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05
Emission Monitoring	
1. There are no specific emission monitoring requirements for this unit.	
Recordkeeping and Reporting Requirements	
1. The permittee shall comply with the applicable recordkeeping and reporting requirements of 40 CFR Part 63, Subpart DDDDD for the boiler.	Rule 335-3-11-.06(107) 40 CFR §63.7550 40 CFR §63.7555
2. The permittee must record and maintain records of the amount of natural gas combusted in the boiler during each calendar month.	Rule 335-3-10-.02(2)(c) 40 CFR §60.48c(g)(2)
3. The permittee shall comply with the recordkeeping and reporting requirements of the Mandatory Greenhouse Gas Reporting Rule in 40 CFR Part 98 for the boiler.	40 CFR Part 98

AIR PERMIT

PERMITTEE: ALABAMA POWER COMPANY

FACILITY NAME: BARRY STEAM ELECTRIC GENERATING PLANT

LOCATION: BUCKS, MOBILE COUNTY, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE, OR DEVICE
503-1001-X016	Two 1500 kW Diesel Emergency Generator Engines
	236 kW Diesel Emergency Fire Pump Engine

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, Ala. Code §§ 22-28-1 to 22-28-23, as amended, the Alabama Environmental Management Act, Ala. Code §§ 22-22A-1 to 22-22A-17, as amended, and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: TBD

Alabama Department of Environmental Management

General Permit Provisos

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission, which requires testing, will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. Unless otherwise specified in the unit-specific provisos of this permit, in the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants which are above an applicable standard, the person responsible for such equipment shall notify the Air Division within an additional 24 hours or the next working day and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

6. All deviations from the requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regard to the date, time, duration, cause, and corrective actions taken to bring the source(s) back into compliance.

7. Unless otherwise specified, this process for which this permit is issued shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

8. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

9. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without

authorization could result in revocation of this permit.

10. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

11. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

12. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

13. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

14. The Air Division must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

    To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

    a. The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

    b. A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

    c. A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

    d. A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

    A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

    All test reports must be submitted to the Air Division within 15 days of the actual completion of the test, unless an extension of time is specifically approved by the Air Division.

15. Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.

    Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:

a. by the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;

b. by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

c. by paving;

d. by the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;

Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.

16. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3) approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

17. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

18. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

19. The permittee shall keep this permit under file or on display at all times at the site where the facility for which the permit is issued is located and shall make the permit readily available for inspection by any or all persons who may request to see it.

20. An annual compliance certification shall be submitted by November 30, covering the reporting period of October 1 through September 30, unless more frequent periods are specified according to the specific rule governing the source or required by the Department.

(a) The compliance certification shall include the following:

a. The identification of each term or condition of this permit that is the basis of the certification;

b. The compliance status;

c. The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);

d. Whether compliance has been continuous or intermittent; and

e. Such other facts as the Department may require in order to determine the compliance status of the source.

(b) The compliance certification shall be submitted to:

Alabama Department of Environmental Management
Air Division
P.O. Box 301463
Montgomery, AL 36130-1463

Emergency Engines
Provisos

	Regulations
Applicability	
1. These units are part of a source subject to the applicable requirements of ADEM Admin. Code r. 335-3-16, "Major Source Operating Permits".	Rule 335-3-16-.03
2. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01, "Control of Particulate Emissions – Visible Emissions".	Rule 335-3-4-.01
3. These units have limits in accordance with the applicable requirements of ADEM Admin. Code r. 335-3-14-.04, "Air Permits Authorizing Construction in Clean Air Areas [Prevention of Significant Deterioration]".	Rule 335-3-14-.04 (BACT)
4. These units are subject to the applicable requirements of 40 CFR Part 63, Subpart ZZZZ, "National Emissions Standards for Hazardous Air Pollutant Emissions from Stationary Reciprocating Internal Combustion Engines".	Rule 335-3-11-.06(103) 40 CFR §63.6585
5. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines".	Rule 335-3-10-.02(87) 40 CFR §60.4200(a)(2)
6. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart A, "General Provisions".	Rule 335-3-10-.02(1) 40 CFR §60.1(a) 40 CFR §60.4218
Emission Standards	
1. By meeting the applicable requirements of 40 CFR Part 60, Subpart IIII for the fire pump engine, the permittee is considered to be in compliance with 40 CFR Part 63, Subpart ZZZZ.	Rule 335-3-11-.06(103) 40 CFR §63.6590(c)
2. The emergency fire pump engine is subject to the applicable requirements under Table 4 of 40 CFR Part 60, Subpart IIII.	Rule 335-3-10-.02(87) 40 CFR §60.4205(c)
3. As new emergency stationary RICE with displacements less than 30 liters per cylinder that are not fire pump engines, the emergency generators are subject to the emission standards specified in 40 CFR §60.4202.	Rule 335-3-10-.02(87) 40 CFR §60.4205(b)

	Regulations
4. These units must use diesel fuel that meets the requirements in 40 CFR §80.510(b) for nonroad diesel fuel.	Rule 335-3-10-.02(87) 40 CFR §60.4207
5. These units must be operated and maintained as specified in 40 CFR §60.4211(a).	Rule 335-3-10-.02(87) 40 CFR §60.4211(a)
6. As emergency stationary RICE, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for more than 50 hours per year, as described below, is prohibited. a. There is no limit on the use of emergency stationary RICE in emergency situations. b. The emergency stationary RICE may be operated for any combination of the purposes specified in 40 CFR §§60.4211(f)(2)(i) and 60.4211(f)(3) for a maximum of 100 hours per calendar year.	Rule 335-3-10-.02(87) 40 CFR §60.4211(f)
7. The permittee shall not discharge to the atmosphere particulate of an opacity greater than 20%, as determined by a six-minute average, except that during one six-minute period in any sixty (60) minute period, the permittee may discharge into the atmosphere particulate of an opacity not greater than 40%.	Rule 335-3-4-.01(1)
8. The Non-methane Hydrocarbons + Nitrogen oxides (NMHC + NOx) emissions from each emergency generator engine shall not exceed 4.8 g/bhp-hr.	Rule 335-3-14-.04 (BACT)
9. The Non-methane Hydrocarbons + Nitrogen oxides (NMHC + NOx) emissions from the fire pump engine shall not exceed 3.0 g/bhp-hr.	Rule 335-3-14-.04 (BACT)
10. The Carbon Monoxide (CO) emissions from each emergency engine shall not exceed 2.6 g/bhp-hr.	Rule 335-3-14-.04 (BACT)
11. The filterable Particulate Matter (PM) emissions from each emergency engine shall not exceed 0.15 g/bhp-hr.	Rule 335-3-14-.04 (BACT)
12. The emergency engines shall only combust ultra-low sulfur diesel fuel which contains no more than 15 ppm sulfur.	Rule 335-3-14-.04 (BACT)
13. The emergency engines shall utilize good combustion practices.	Rule 335-3-14-.04 (BACT)
Compliance and Performance Test Methods and Procedures	
1. The permittee shall comply with the emission standards by purchasing	Rule 335-3-10-.02(87)

	Regulations
an emergency firewater pump engine certified by the manufacturer to the emission standards in 40 CFR §60.4202(d), as applicable, for the same model year and maximum engine power.	40 CFR §60.4211(c)
2. The permittee shall comply with the emission standards by purchasing emergency generator engines 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.	Rule 335-3-10-.02(87) 40 CFR §60.4211(c)
3. Compliance with the opacity standard shall be determined by EPA Reference Method 9, as found in 40 CFR Part 60, Appendix A.	Rule 335-3-1-.05
Emission Monitoring	
1. The engines must be equipped with a non-resettable hour meter unless the engines meet the standards applicable to non-emergency engines.	Rule 335-3-10-.02(87) 40 CFR §60.4209(a)
Recordkeeping and Reporting Requirements	
1. The permittee shall keep records of the operation of the engines in emergency and non-emergency service that are recorded through the non-resettable hour meter. The permittee must also record the time of operation of the engines and the reason the engine was in operation during that time.	Rule 335-3-10-.02(87) 40 CFR §60.4214(b)
2. The permittee shall submit the applicable notifications for the emergency generators as specified in 40 CFR §63.6645(f).	Rule 335-3-11-.06(103) 40 CFR §63.6645(f)

Alternate Operating Scenario	
1. If these units are operated as non-emergency stationary RICE, the permittee shall notify ADEM and comply with the applicable provisions of ADEM Admin. Code r. 335-3-10-.02(87), "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (Subpart IIII)" and 335-3-11-.06(103), "National Emissions Standards for Hazardous Air Pollutant Emissions from Stationary Reciprocating Internal Combustion Engines (Subpart ZZZZ)" notwithstanding other provisions of this permit to the contrary.	Rule 335-3-10-.02(87) (incorporating 40 CFR Part 60 Subpart IIII)