PRELIMINARY DETERMINATION
PowerSouth Energy Cooperative – Lowman Energy Center
Facility No. 108-0001
454 MW Natural Gas Simple Cycle Turbine
Air Permit Nos. X008 and X009

INTRODUCTION

On August 6, 2025, on behalf of PowerSouth Energy Cooperative (PowerSouth), All4 submitted an air permit application to the Department for a project to take place at the Charles R. Lowman Energy Center (LEC) in Leroy, Alabama. Additional information was received on September 16, 2025, October 17, 2025, and October 27, 2025. A revised application was received on February 16, 2026. PowerSouth has proposed to install a 454 megawatt (MW) natural gas-fired simple-cycle (NGSC) combustion turbine generator (CTG) and a 9.9 MMBtu/hr fuel gas heater. The facility has stated that there will be no modifications to the existing emission sources. PowerSouth is currently a major source of regulated air pollutants with respect to Title V and an area source for hazardous air pollutants (HAP). The facility is operating under Major Source Operating Permit (MSOP) No. 108-0001 and the following air permits:

Permit Number	Permit Description	Issuance Date
108-0001-X006	Natural Gas-Fired Fuel Heater	August 21, 2019
108-0001-X007	3353 HP Diesel Emergency Generator Engine 422 HP Diesel Emergency Firewater Pump Engine	August 21, 2019
108-0001-X005 (reissue)	Combined Cycle Combustion Turbine and Heat Recovery Steam Generator with Duct Burner, Oxidation Catalyst, and Selective Catalytic Reduction (SCR)	May 9, 2025

FACILITY DESCRIPTION

PowerSouth is an electric power generation facility. The facility currently operates a 720 MW natural gas combine cycle (NGCC) unit, a 9.9 MMBtu/hr fuel gas heater, a 2,500 kilowatt (KW) ultra-low sulfur fired (ULSD) diesel firewater pump, and a cooling tower. The facility has stated that there will be no changes to the existing equipment.

PROJECT DESCRIPTION

PowerSouth has proposed to install a 454 MW NGSC CTG and a 9.9 MMBtu/hr fuel gas heater. The proposed fuel heater will condition the natural gas prior to combustion in the CTG and prevent condensation of the natural gas. The proposed CTG will be equipped with dry low-NO_x combustors and a selective catalytic reduction (SCR) system to minimize nitrogen oxide (NO_x) emissions. The proposed CTG will also be equipped with an oxidation catalyst system to control carbon monoxide (CO) and volatile organic compound (VOC) emissions. The proposed CTG and fuel gas heater will exclusively fire pipeline-quality natural gas.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The proposed project would qualify as a major source modification since the emissions of carbon monoxide (CO), nitrogen oxides (NO_x), 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) as a precursor for ozone, 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(2)(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). Note: The PSD significant threshold for PM accounts

for only filterable particles, while the PM_{10} and $PM_{2.5}$ PSD significant thresholds account for filterable and condensable particles. The facility has taken a conservative approach by not speciating the particulate emissions and assuming PM emissions are equal to PM_{10} and $PM_{2.5}$ emissions.

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 the pollutant's significance threshold, a PSD review is not necessary for that pollutant.

The following table shows the worst-case net emission increases as a result of this proposed project and the PSD significant emissions threshold values:

Pollutant	Proposed Net Emission Rate Increase (TPY)	PSD Significant Threshold (TPY)	Significant Source
Carbon Monoxide (CO)	385.70	100	Yes
Nitrogen Oxides (NO_X)	366.08	40	Yes
Sulfur Dioxide (SO_2)	38.33	40	No
Particulate Matter (PM)*	101.0	25	Yes
Particulate Matter < 10µ (PM_{10})*	101.0	15	Yes
Particulate Matter < 2.5µ ($PM_{2.5}$)*	101.0	10	Yes
Ozone**	115.26	40	Yes
Lead (Pb)	2.13E-05	0.6	No
Sulfuric Acid Mist (H_2SO_4)	4.68	7	No
Greenhouse Gases (GHG) CO_{2e}	2,146,930.09	75,000	Yes

*Particulate matter emissions include filterable and condensable particles.
**Ozone emission estimates are calculated as volatile organic compounds (VOC), a precursor for ozone.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The Clean Air Act (CAA) prescribes several technology-based limitations affecting new or modified air pollution sources. Among these limitations is BACT. Any new or modified units located at a major source for PSD with significant net emission increases must be constructed with BACT. Individual BACT determinations are performed for each pollutant subject to a PSD review emitted from the same emission unit. Each BACT analysis is determined on a case-by-case basis, evaluating the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. The BACT analyses for the 454 MW natural gas-fired simple-cycle CTG and the 9.9 MMBtu/hr fuel gas heater are discussed below.

Carbon Monoxide (CO)

Carbon monoxide (CO) emissions from the combustion sources are a result of incomplete combustion of carbon-based fuels. The primary factors influencing CO formation are temperature and residence time within the high temperature environment of the combustor.

TURBINE

The facility identified good combustion practices and an oxidation catalyst as available control technologies for CO emissions from the CTG. These control technologies have been demonstrated on similar sources in the RACT/BACT/LAER Clearinghouse (RBLC) database and would be considered technically feasible options. PowerSouth did not eliminate either of the potential control technologies based on economic infeasibility. The use of an oxidation catalyst would be considered the most effective CO control for the CTG with an 80% reduction in emissions. PowerSouth has proposed utilizing an oxidation catalyst and good combustion practices as BACT for the CTG and proposed a CO limit of 2 ppmvd @ 15% O_2 and 20 lb/hr, based on the average of three test runs. 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 CTG.

FUEL HEATER

The facility identified good combustion practices and an oxidation catalyst as available control technologies for CO emissions from the fuel heater. PowerSouth evaluated each of the potential control technologies for technical feasibility. The use of good combustion practices would be implementing appropriate maintenance procedures and maintaining optimum combustion efficiency. These practices are essential for the operation and lifespan of the proposed fuel heater. The facility has stated that good combustion practices are a technically feasible option to control CO emissions from the fuel heater. For an oxidation catalyst to be an effective control option, the system would need to be installed and operated under specific conditions. Since the proposed fuel heater would be expected to operate for short periods of time, the unit would not consistently have the appropriate exhaust gas temperature necessary for effective application of an oxidation catalyst. PowerSouth stated that the RBLC did not demonstrate add on control technology for similar sized heaters. Therefore, the facility eliminated an oxidation catalyst because it would be technically infeasible for the proposed unit.

PowerSouth has proposed using good combustion practices as BACT for the fuel heater and proposed a CO limit of 0.037 lb/MMBtu and 0.37 lb/hr, based on the average of three test runs. 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 fuel heater.

Nitrogen Oxides (NO_x)

Nitrogen oxides (NO_x) emissions from combustion sources are formed by three mechanisms: thermal, fuel, and prompt. Thermal NO_x is generated from the combination of elemental nitrogen and oxygen in the combustion air. Fuel NO_x is generated from the oxidation of nitrogenous compounds that are present in the fuel. Prompt NO_x is generated by molecular nitrogen in the air combining with fuel in fuel-rich conditions occurring in the earliest stages of combustion. The technologies used to control NO_x emissions either reduce NO_x formation caused by combustion or reduce NO_x emissions after formation via an add on control device.

TURBINE

The facility identified good combustion practices, clean fuels, water or steam injection, dry low-NO_x combustors, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), low-NO_x

burners (LNB), ultra-low-NO_x burners (ULNB), and use of oxygen instead of air in combustion process as potential control technologies for NO_x emissions from the CTG.

PowerSouth evaluated each of the potential control technologies for technical feasibility. The facility stated that good combustion practices, clean fuels, dry low-NO_x combustors, SCR, LNB, and ULNB would all be technically feasible. PowerSouth determined that water or steam injection, SNCR, and the use of oxygen instead of air in the combustion process would be technically infeasible. The facility eliminated water or steam injection as a potential control technology for NO_x emissions from the CTG because the technology has not been applied extensively for natural gas fired simple cycle CTGs and does not demonstrate superior NO_x control. The facility eliminated SNCR as a potential control technology for NO_x emissions from the CTG because the exhaust gas temperature from the proposed CTG would be below the exhaust temperature required for the SNCR system to be efficient. The facility also eliminated the use of oxygen instead of air in the combustion process as a potential control technology for NO_x emissions from the CTG because the material for the proposed CTG would not withstand the stronger and hotter flame produced by using oxygen.

PowerSouth ranked the remaining control technologies based on the effectiveness at reducing NO_x emissions. The following table contains the remaining control technologies and the corresponding NO_x reduction efficiency.

Control Technology	Reduction Efficiency
SCR	87%
Dry low-NO_x Combustors/LNB/ULNB	15-60%
Good Combustion Practices/Clean Fuels	Varies (< 87%)

The use of SCR would be considered the most effective NO_x control for the CTG with an 87% reduction in emissions. PowerSouth has proposed using SCR, dry low-NO_x combustors, good combustion practices, and clean fuels as BACT for the CTG and proposed a NO_x limit of 5 ppmvd @ 15% O_2 and 82 lb/hr, compliance is based on a 3-hour rolling average as determined by continuous emission monitoring system (CEMS). The emission limit does not apply during periods of startup, shutdown, or load changes. During these periods, the facility shall take all reasonable actions to minimize the magnitude and duration of emissions. 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 CTG.

FUEL HEATER

The facility identified good combustion practices, SCR, SNCR, LNB, ULNB, and flue gas recirculation as potential control technologies for NO_x emissions from the fuel heater. PowerSouth evaluated each of the potential control technologies for technical feasibility. The facility stated that good combustion practices and LNB would be technically feasible. PowerSouth determined that SCR, SNCR, ULNB, and flue gas recirculation would be technically infeasible. The facility eliminated SCR as a potential control technology for NO_x emissions from the fuel heater because the fuel heater will not consistently operate at steady-state loads and will not achieve the exhaust temperature required for the SCR to be effective. The facility eliminated SNCR as a potential control technology for NO_x emissions from the fuel heater because the exhaust gas temperature from the proposed fuel heater

would be below the exhaust temperature required for the SNCR system to be efficient. The facility also eliminated the use of ULNB as a potential control technology for NO_x emissions from the fuel heater because ULNB are not universally adaptable to all boiler designs and the longer flame pattern can subject the fuel heater to unacceptable damage, safety concerns, and operability and reliability problems. The facility also eliminated the use of flue gas recirculation as a potential control technology for NO_x emissions from the fuel heater because the technology has not been applied on similar sized units at similar facilities with limited operations.

The use of LNB would be considered the most effective NO_x control for the fuel heater. PowerSouth has proposed using LNB and good combustion practices as BACT for the fuel heater and proposed a NO_x limit of 0.010 lb/MMBtu and 0.10 lb/hr, based on the average of three test runs. 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 fuel heater.

Particulate Matter (PM/PM10/PM2.5)

Particulate matter (PM) emissions from combustion sources are a combination of filterable and condensable particles. The facility has conservatively assumed PM, PM_{10}, and $PM_{2.5}$ emissions are equal. The filterable portion of PM is the result of incomplete combustion and impurities in the fuel, while the condensable portion of PM is the result of the formation of sulfates and other compounds.

TURBINE

The facility identified good combustion practices, low sulfur fuels, fabric filter baghouse, electrostatic precipitator (ESP), wet electrostatic precipitator (WESP), and scrubber as potential control technologies for PM emissions from combustion sources. PowerSouth evaluated each of the potential control technologies for technical feasibility. The facility stated that good combustion practices and the use of low sulfur fuels would be technically feasible. The facility eliminated the use of fabric filter baghouse, ESP, WESP, and scrubber as a potential control technology for PM emissions from the CTG because these types of add-on controls have not been demonstrated on similar types of units.

The use of good combustion practices and low sulfur fuels would be considered the most effective PM control for the CTG. PowerSouth has proposed using good combustion practices and using natural gas with a sulfur content of 0.8 gr S/100 scf or less as BACT for the CTG and proposed a total PM limit of 0.00585 lb/MMBtu and 24 lb/hr, based on the average of three test runs. It is noted that the total PM limit includes filterable and condensable particles. 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 CTG.

FUEL HEATER

The facility identified good combustion practices, low sulfur fuels, fabric filter baghouse, ESP, WESP, and scrubber as potential control technologies for PM emissions from the combustion sources. PowerSouth evaluated each of the potential control technologies for technical feasibility. The facility stated that good combustion practices and the use of low sulfur fuels would be technically feasible. The facility eliminated the use of fabric filter baghouse, ESP, WESP, and scrubber as a potential control technology for PM emissions from the fuel heater because these types of add-on controls have not been demonstrated on similar types of units.

The use of good combustion practices would be considered the most effective PM control for the fuel heater. PowerSouth has proposed using good combustion practices and using natural gas with a sulfur content of 0.8 gr S/100 scf or less as BACT for the fuel heater and proposed a PM limit of 0.0048 lb/MMBtu and 0.05 lb/hr, based on the average of three test runs. 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 fuel heater.

Volatile Organic Compounds (VOC)

Volatile organic compound (VOC) emissions from the combustion sources are a result of incomplete combustion. The primary factors influencing VOC formation are temperature and residence time within the high temperature environment of the combustor.

TURBINE

The facility identified good combustion practices, clean fuels, and an oxidation catalyst as available control technologies for VOC emissions from the CTG. It is noted that an oxidation catalyst is commonly used to reduce VOC emissions in conjunction with its target pollutant CO. These control technologies have been demonstrated on similar sources in the RBLC database and would be considered technically feasible options. PowerSouth did not eliminate any of the potential control technologies based on economic infeasibility. The use of an oxidation catalyst would be considered the most effective VOC control for the CTG with a 9% reduction in emissions. PowerSouth has proposed utilizing an oxidation catalyst and good combustion practices as BACT for the CTG and proposed a VOC limit of 1 ppmvd @ 15% O_2 and 6 lb/hr, based on the average of three test runs. 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 CTG.

FUEL HEATER

The facility identified good combustion practices, oxidation catalyst, and a thermal oxidizer as available control technologies for VOC emissions from the fuel heater. PowerSouth evaluated each of the potential control technologies for technical feasibility. The facility stated that good combustion practices would be technically feasible. PowerSouth determined that an oxidation catalyst and a thermal oxidizer would be technically infeasible. The facility eliminated an oxidation catalyst and thermal oxidizer as potential control technologies for VOC emissions from the fuel heater because the unit will not achieve the exhaust temperature required for either control technology to be effective. These types of control devices have not been demonstrated on similar sources at similar types of facilities.

The use of good combustion practices would be considered the most effective VOC control for the fuel heater. PowerSouth has proposed using good combustion practices as BACT for the fuel heater and proposed a VOC limit of 0.01 lb/MMBtu and 0.05 lb/hr, based on the average of three test runs. 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 fuel heater.

Greenhouse Gases (GHG) CO_2e

Greenhouse gas (GHG) emissions result from the combustion of fuels. The typical GHG pollutants emitted from stationary combustion sources consist of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The GHG emissions are converted to a carbon dioxide equivalent (CO_2e) basis using their individual Global Warming Potential (GWP) value.

TURBINE

The facility identified energy efficient and inherently lower-emitting processes/work practices/design, good combustion practices, and carbon capture and storage (CCS) as available control technologies for GHG emissions from the CTG. PowerSouth determined all of the potential control technologies would be technically feasible. PowerSouth ranked the technologies based on the effectiveness at reducing GHG emissions. The following table contains the remaining control technologies and the corresponding GHG reduction efficiency.

Control Technology	Reduction Efficiency
CCS	90%
Energy Efficiency	10-50%
Good Combustion Practices	10-50%

PowerSouth evaluated the economic feasibility of CCS for the CTG. The facility determined that the cost for CCS would be approximately \$82/ton CO_2 captured, equating to an annual cost of approximately \$153.8 million when considering the size of the unit. The levelized cost of electricity from natural gas fired generation is reported to be \$183-240 million per year. Therefore, PowerSouth eliminated CCS as a control technology for GHG emissions based on economic infeasibility.

PowerSouth has proposed using energy efficient and inherently lower-emitting processes/work practices/design and good combustion practices as BACT for the CTG and proposed a GHG limit of 120 lb CO_2/MMBtu, based on a 12 operating month rolling average basis. 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 CTG.

FUEL HEATER

The facility identified energy efficient design and work practices as available control technologies for GHG emissions from the fuel heater. These control technologies have been demonstrated on similar sources in the RBLC database and would be considered technically feasible options. PowerSouth did not eliminate any of the potential control technologies based on economically infeasibility. PowerSouth has proposed using energy efficient design and work practices as BACT for the fuel heater and proposed a GHG limit of 120.0 lb/MMBtu, based on a 12 month rolling average. 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 fuel heater.

BACT Summary Tables

Proposed BACT limits for the CTG

Pollutant	Proposed BACT Limit				Averaging Period
Carbon Monoxide (CO)	2	ppmvd @ 15% O2	20	lb/hr	Average of three one-hour stack test runs
Nitrogen Oxides (NO_X)	5	ppmvd @ 15% O2	82	lb/hr	3-hour rolling
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	0.00585	lb/MMBtu	24	lb/hr	Average of three one-hour stack test runs
Volatile Organic Compounds (VOC)	1	ppmvd @ 15% O2	6	lb/hr	Average of three one-hour stack test runs
Greenhouse Gases (GHG) CO_{2e}	120		lb CO_2/MMBtu		12 operating month rolling average basis

Proposed BACT limits for the Fuel Heater

Pollutant	Proposed BACT Limit				Averaging Period
Carbon Monoxide (CO)	0.037	lb/MMBtu	0.37	lb/hr	Average of three one-hour stack test runs
Nitrogen Oxides (NO_X)	0.010	lb/MMBtu	0.10	lb/hr	Average of three one-hour stack test runs
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	0.0048	lb/MMBtu	0.05	lb/hr	Average of three one-hour stack test runs
Volatile Organic Compounds (VOC)	0.005	lb/MMBtu	0.05	lb/hr	Average of three one-hour stack test runs
Greenhouse Gases (GHG) CO_{2e}	120		lb CO_2/MMBtu		12 month rolling average basis

AIR QUALITY ANALYSIS (MODELING)

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. Ambient impacts of non-criteria pollutants must also be evaluated. 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. It is noted that the VOCs emissions are a precursor for ozone. The following table presents the applicable standards for the pollutants under PSD review:

Pollutant		Averaging Time	Primary Standard	Secondary Standard
Carbon Monoxide (CO)		8-hour	9 ppm	---
		1-hour	35 ppm	---
Nitrogen Dioxide (NO_2)		1-hour	100 ppb	---
		Annual	53 ppb	53 ppb
Ozone (O_3)		8-hour	0.070 ppm	0.070 ppm
Particle Pollution (PM)	**$PM_{2.5}$**	Annual	9.0 $\mu g/m^3$	15.0 $\mu g/m^3$
		24-hour	35 $\mu g/m^3$	35 $\mu g/m^3$
	PM_{10}	24-hour	150 $\mu g/m^3$	150 $\mu g/m^3$

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. The revised application resulted in a minimal decrease in potential emissions and would not require a revised air quality analysis.

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. The following is a brief synopsis of each class area and how it relates to this project. 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 Class I and II PSD increments for the pollutants under PSD review.

Pollutant		Averaging Time	Class I (µg/m^3)	Class II (µg/m^3)
Nitrogen Dioxide (NO_2)		Annual	2.5	25
Particle Pollution (PM)	**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:

Class I Areas:
Class I Areas have the smallest increments and thus allow only a small degree of air quality deterioration. Air Permit application forms submitted by PowerSouth document that the closest Class I Area, the Breton Wildlife Refuge, is approximately 180 km from the facility. Therefore, a Class I increment analysis was not required by the Department. However, PowerSouth submitted a Request for Applicability of Class I Area Modeling Analysis Form to the Federal Land Manager (FLM) for review of the proposed project. The FLM determined that no additional analysis is necessary at this time.

Class II Areas:
Class II areas can accommodate normal well-managed industrial growth. PowerSouth 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.

Class III Areas:
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.

Additional Impact Analysis

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: growth, soils and vegetation, and visibility impairment.

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

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, NO_2, PM_{10},

and $PM_{2.5}$ are less than the Class II significant impact level (SIL). In summary, the project is not expected to result in significant impact on soil, vegetation, or wildlife in the area surrounding the facility.

Visibility Impairment
For distances greater than 50 km, visibility impairment is considered to take the form of regional haze rather than a distinct plume. PowerSouth performed a Q/d screening analysis to determine if a full Class I Air Quality Related Values (AQRV) evaluation would be required for the proposed project. The Q/d screening analysis calculates a ratio of the potential project emissions of visibility-impairing pollutants (SO_2, NO_2, PM_{10}, sulfuric acid mist) in tons per year to the distance in kilometers to the Class I area. Since the ratio was less than 10, no further analyses were required.

STATE REGULATIONS

CHAPTER 335-3-1, GENERAL PROVISIONS

ADEM Admin. Code r. 335-3-1-.04, "Monitoring, Records, and Reporting"

ADEM Admin. Code r. 335-3-1-.04(1) states the Director may require the owner or operator of any air contaminant source to establish and maintain such records; make such reports; install, use, and maintain such monitoring equipment or methods; sample such emissions in accordance with such methods at such locations, intervals, and procedures as the Director may prescribe; and provide such periodic emission reports as required in paragraph (2) of this Rule.

The Department cites this rule (along with the similar r. 335-3-16-.05(c) in the context of major source operating permits) as the authority to stipulate monitoring, recordkeeping, and reporting requirements as needed to determine continuous compliance with operating and emission standards such as the BACT limits determined above.

CHAPTER 335-3-4, CONTROL OF PARTICULATE EMISSIONS

ADEM Admin. Code r. 335-3-4-.01, "Visible Emissions"

ADEM Admin. Code r. 335-3-4-.01(1)(a) states that no person shall emit particulate emissions to the atmosphere of an opacity of greater than twenty percent (20%) over a six (6) minute period, except for one six-minute period in any sixty period. ADEM Admin. Code r. 335-3-4-.01(1)(b) states that during one six-minute period in any sixty-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 state opacity standard applies at all times. Since the proposed CTG and fuel heater would combust natural gas only, opacity is expected to be negligible during operation of the units.

ADEM Admin. Code r. 335-3-4-.02, "Fugitive Dust and Fugitive Emissions

All major facilities are now required to submit a Facility-Wide Fugitive Dust Plant, if necessary. There are no raw materials, storage piles, products, etc. capable of generating fugitive dust at this facility. All plant roads are paved or graveled, thereby significantly limiting the potential for fugitive dust. In other words, emissions are expected to be insignificant, as is the likelihood that the facility will violate the general SIP requirements related to fugitive dust. Therefore, additional specific requirements for fugitive dust, including additional monitoring, recordkeeping, or reporting requirements, are not necessary for this facility in order to assure compliance with the SIP.

ADEM Admin. Code r. 335-3-4-.03, "Fuel Burning Equipment"

PowerSouth is located in Washington County, which is currently classified as a Class 2 County, since the county is not currently listed in Appendix A of ADEM Admin. Code r. 335-3. However, as stated in ADEM Admin. Code r. 335-3-4-.03(4), any new fuel-burning sources emitting PM will be subject to the rules and regulations for Class 1 Counties, regardless of their location. ADEM Admin. Code r. 335-3-4-.03(1) states that no person shall cause or permit the emission of particulate matter from fuel-burning equipment in a Class 1 County in excess of the amount shown in Table 4-1 for the heat input allocated to such source.

It is noted that the facility has proposed more stringent total PM ($PM/PM_{10}/PM_{2.5}$) limits for the CTG and the fuel heater as part of the BACT analysis, and this limit would be met by complying with those more stringent limits.

CHAPTER 335-3-5, CONTROL OF SULFUR COMPOUND EMISSIONS

ADEM Admin. Code r. 335-3-5-.01, "Fuel Combustion"

PowerSouth is located in Washington County, which is currently classified as a Category II County, as stated in Appendix B of ADEM Admin. Code r. 335-3. Therefore, the proposed CTG and fuel heater located at the facility would be subject to the Category II County SO_2 emission limit of 4.0 lb/MMBtu.

The proposed CTG and fuel heater would meet this limit by combusting natural gas only.

ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36, Cross-State Air Pollution Rule (CSAPR)

The proposed CTG would be subject to the Cross-State Air Pollution Rule (CSAPR) and would be subject to the applicable provisions in ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36 for sulfur dioxide (SO_2).

CHAPTER 335-3-8, CONTROL OF NITROGEN OXIDE EMISSIONS

ADEM Admin. Code r. 335-3-8-.07 through 335-3-8-.70, Cross-State Air Pollution Rule (CSAPR)

The proposed CTG would be subject to the Cross-State Air Pollution Rule (CSAPR) and would be subject to the applicable provisions in ADEM Admin. Code r. 335-3-8-.07 through 335-3-5-.70 for nitrogen oxides (NO_x).

CHAPTER 335-3-10, STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

The EPA regulations governing standards of performance for new stationary sources (40 CFR Part 60) are incorporated by reference in ADEM Admin. Code r. 335-3-10.

CHAPTER 335-3-14, AIR PERMITS

ADEM Admin. Code r. 335-3-14-.04, "Air Permits Authorizing Construction In Clean Air Areas [Prevention of Significant Deterioration Permitting (PSD)]"

ADEM Admin. Code r. 335-3-14-.04(17)(e)3. states the owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in subparagraph (17)(e)1.(ii) of this Rule; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following the resumption of regular operations after the change, or for a period of 10 years following resumption of

regular operations after the change if the project increases the design capacity or potential to emit of the regulated NSR pollutant at such emissions unit. Since there is a reasonable possibility that the proposed project could result in a significant emissions increase of sulfur dioxide (SO_2), the facility will be required to calculate, record, and submit a report of annual SO_2 emissions for 10 years following the completion of the proposed project.

The annual reporting requirements are addressed in ADEM Admin. Code r. 335-3-14-.04(17)(e)4. The report should be submitted to the Director within 60 days after the end of each year during which records must be generated. The report shall contain the following:

(i) All information required by subparagraph (17)(e)1. of this Rule.
(ii) The name, address and telephone number of the major stationary source;
(iii) The annual emissions as calculated pursuant to subparagraph (17)(e)3. of this Rule; and
(iv) Any other information that the owner or operator wishes to include in the report.

The permittee shall maintain the records as required by ADEM Admin. Code r. 335-3-14-.04(17)(e)5. These records must be made available for review upon a request for inspection by the Department.

CHAPTER 335-3-16, MAJOR SOURCE OPERATING PERMITS

ADEM Admin. Code r. 335-3-16-.03(1)(a), "Applicability"

PowerSouth is currently an area source for hazardous air pollutants (HAP). ADEM Admin. Code r. 335-3-16-.01(1)(q)1.(i) defines a major source as a stationary source that emits or has the potential to emit 10 TPY or more of any individual HAP or 25 TPY or more of any combination of HAPs. The facility-wide potential HAP emissions would remain below the major source threshold following the proposed project. To calculate the potential HAP emissions, the facility utilized AP-42 emission factors for natural gas fired turbines, natural gas combustion, large diesel engines and small diesel engines. The facility also used a manufacturer's guarantee to calculate formaldehyde emissions from the proposed and existing CTGs. The potential emissions were calculated using an operating schedule of 8,760 hours per year for the CTGs and fuel heaters, 7,250 hours per year for the existing duct burner, and 500 hours for the emergency generator and firewater pump. The table below contains the potential emissions for the greatest individual HAP emitted by the facility and the total HAPs emitted by the facility.

Emission Unit	Individual HAP (TPY)[1]	Total HAP (TPY)
LEC Unit 3	4.2	9.9
Fuel Gas Heater	0.00319	0.0803
Existing NGCC	4.6	14.2
Existing Fuel Gas Heater	0.003	0.0803
Existing Emergency Diesel Generator	0.00045	0.0106
Existing Diesel Fire Water Pump	0.0019	0.00679
Total:	8.87	24.28
Major Source HAP Threshold:	10	25
Significant Source:	No	No

[1]Greatest individual HAP is formaldehyde.

The potential HAP emissions from the facility are below the major source threshold; however, to ensure the facility remains an area source for HAP emissions, the facility will be limited to emitting 9.5 TPY of any individual HAP and 24.5 TPY of any total combination of HAPs during any rolling 12-month period. The Department is requiring the facility to conduct an initial performance test for formaldehyde for the proposed turbine. To demonstrate continuous compliance, the facility must calculate and record the facility-wide HAP emissions on a monthly basis and utilize these to calculate the rolling 12-month value. The HAP emissions from the units should be calculated using the approved emission factors located in the application submitted on February 16, 2026 (see Table B-4 of Appendix B). Any changes to the emission factors used by the facility must be approved by the Department. The facility shall maintain records of these calculations for a period of five years.

ADEM Admin. Code r. 335-3-16-.04, "Permit Application Requirements"

PowerSouth is currently operating under MSOP No. 108-0001. The proposed CTG and fuel heater would not contravene any existing requirements in the current MSOP. Since the equipment would be newly constructed, PowerSouth would have one year from startup of the units to submit a significant modification application to the Department to incorporate the air permits into the Title V MSOP.

CHAPTER 335-3-18, ACID RAIN PROGRAM-PERMIT REGULATION

The EPA regulations governing the Acid Rain Program – Permits Regulation (40 CFR Part 72) are incorporated by reference in ADEM Admin. Code r. 335-3-18. The Acid Rain Program is the national sulfur dioxide and nitrogen oxides air pollution control and emission reduction program. As stated in §72.30(b)(2)(ii), since the proposed CTG is a new unit under §72.6(a)(3)(i), the facility shall submit a complete Acid Rain permit application at least 24 months before the date on which the unit commences operation of any mechanical, chemical, or electronic processes, including start-up of an emissions control technology or emissions monitor or of a unit's combustion chamber.

FEDERAL REGULATIONS

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR Part 60, Subpart A – "General Provisions"

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

40 CFR Part 60, Subpart Db – "NSPS for Industrial-Commercial-Institutional Steam Generating Units"

The Department reviewed 40 CFR Part 60, Subpart Db (*NSPS for Small Industrial-Commercial-Institutional Steam Generating Units*) for potential applicability. This subpart applies to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuel combusted in the steam generating unit of greater than 29 MW (100 MMBtu/hr). Since the proposed CTG would not combust fuel to produce steam, the unit would not meet the definition of a *steam generating unit*, as defined in §60.41b. The proposed fuel heater would be newly constructed, but the heat input capacity of the unit is less than 100 MMBtu/hr. Therefore, the fuel heater would not be subject to this subpart.

40 CFR Part 60, Subpart Dc – "NSPS for Small Industrial-Commercial-Institutional Steam Generating Units"

The Department reviewed 40 CFR Part 60, Subpart Dc (*NSPS for Small Industrial-Commercial-Institutional Steam Generating Units*) for potential applicability. This subpart applies to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity greater than or equal to 2.9 MW (10 MMBtu/hr) but less than 29 MW (100 MMBtu/hr). The proposed fuel heater would meet the definition of a steam generating unit as defined in NSPS Dc, but the heat input capacity is less than 10 MMBtu/hr. Therefore, NSPS Dc would not be applicable to the proposed fuel heater.

40 CFR Part 60, Subpart GG – "NSPS for Stationary Gas Turbines"

The Department reviewed 40 CFR Part 60, Subpart GG (*NSPS for Stationary Gas Turbines*) for potential applicability. This subpart applies to all stationary gas turbines for which construction, modification, or reconstruction commenced after October 3, 1977, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu/hr), based on the lower heating value of the fuel fired. Since the CTG would be newly construction and has a heat input greater than 10 MMBtu/hr, the unit would be subject to this subpart. However, as stated in §60.4305a(b), any stationary combustion turbine regulated under NSPS KKKKa is exempt from the requirements of NSPS GG. Therefore, there are no requirements of this subpart that would apply to the proposed CTG.

40 CFR Part 60, Subpart KKKK – "NSPS for Stationary Combustion Turbines"

The Department reviewed 40 CFR Part 60, Subpart KKKK (*NSPS for Stationary Combustion Turbines*) for potential applicability. The subpart establishes emission standards and compliance schedules for the control of NO_x and SO_2 emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu/hr) based on the higher heating value of the fuel. On January 15, 2026, the U.S. Environmental Protection Agency (EPA) promulgated NSPS KKKKa. The proposed CTG would be newly constructed and would be subject to the newly promulgated rule. Therefore, as stated in §60.4305(c), the unit would not be subject to the requirements of NSPS KKKK.

40 CFR Part 60, Subpart KKKKa – "NSPS for Stationary Combustion Turbines"

The Department reviewed 40 CFR Part 60, Subpart KKKKa (*NSPS for Stationary Combustion Turbines*) for potential applicability. The subpart establishes emission standards and compliance schedules for the control of NO_x and SO_2 emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after December 13, 2024, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu/hr) based on the higher heating value of the fuel. Since the proposed CTG would be newly construction and would have a heat input greater than 10 MMBtu/hr, the unit would be subject to this subpart, as indicated by §60.4305a(a).

The proposed CTG would be required to meet the applicable NO_x emission standard listed in Table 1 that apply based on the combustion turbine type and size category. The proposed CTG would be classified as a large combustion turbine since the base load rating is greater than 850 MMBtu/hr of heat input. The combustion turbine type is dependent on the utilization rate or loading rate. The unit would either be considered a high-utilization source or a low-utilization source. Each of these subcategories are defined in §60.4420a and are included below.

- *High-utilization source* – means a new medium or large stationary combustion turbine with a 12-calendar-mont capacity factor greater than 45 percent.

- *Low-utilization source* – means a new medium or large stationary combustion turbine with a 12-calendar-month capacity factor less than or equal to 45 percent.

- *Base load rating* – 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel.

The applicable NO_x emission standards specified in Table 1 of the subpart are listed in the table below. The NO_x emission standards are determined on an operating-hour basis and apply at all times that the unit is operating, including periods of startup, shutdown, and malfunction, as stated in §60.4320a(b)(1) and §60.4320a(d). The input-based emissions standards are determined on a 4-operating-hour rolling basis, as stated in §60.4320a(a).

Combustion Turbine Type	Input-based NO_x Emission Standard
High-Utilization Source	5 ppm at 15 percent O_2
Low-Utilization Source	25 ppm at 15 percent O_2
Source operating at less than 70 percent of the base load rating	96 ppm at 15 percent O_2

In order to demonstrate compliance with the NO_x emission limits, the facility has stated that the CTG will be equipped with a NO_x diluent continuous emission monitoring system (CEMS). The requirements of the NO_x CEMS equipment are described in §60.4345a. It is noted that a NO_x diluent CEMS that is installed and certified according to 40 CFR Part 75, Appendix A is acceptable for use under this subpart and the relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis. The initial testing requirements of the NO_x diluent CEMS are listed in §60.4405a. The procedures to identify excess emissions from the NO_x CEMS are located in §60.4350a(a) through (f). The facility must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c), as required by §60.4375a(a). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. Periods of excess emissions and monitor downtime are defined in §60.4380a(b). The report must be submitted by the 30th day following the end of each 6-month period, as stated in §60.4395a and §60.4375a(f).

The facility must not burn any fuel in the proposed CTG which contains total potential sulfur emissions in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output or 26 ng/J (0.060 lb/MMBtu) heat input, as stated in §60.4330a(a)(1) and (2). To demonstrate compliance with the SO_2 fuel-based standard, the facility would be required to conduct an initial and subsequent performance test, as required by §60.4333a(d)(3). To demonstrate compliance with the fuel-based standard for the initial performance test, the facility must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis), as listed in §60.4415a(a). To demonstrate compliance with the fuel-based standard for subsequent performance test, the facility will perform representative fuel sampling following procedures specified in section 2.3.1.4 or

2.3.2.4 of 40 CFR Part 75, Appendix D, as specified in §60.4372a(e). The facility must maintain records of the results of all fuel analyses as required by §60.4390a(f).

40 CFR Part 60, Subpart TTTT – "NSPS for Greenhouse Gas Emissions for Electric Generating Units"

The Department reviewed 40 CFR Part 60, Subpart TTTT (*NSPS for Greenhouse Gas Emissions for Electric Generating Units*) for potential applicability. This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a stationary combustion turbine that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, but on or before May 23, 2023. Since the CTG would be newly constructed, the unit would not be subject to this subpart.

40 CFR Part 60, Subpart TTTTa – "NSPS for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units"

The Department reviewed 40 CFR Part 60, Subpart TTTTa (*NSPS for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units*) for potential applicability. This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. It is noted that the GHG standards are in the form of a limitation on emissions of CO_2. Since the CTG would be newly constructed and has a base load rating greater than 260 gigajoules per hour (GJ/h)(250 MMBtu/hr) of fossil fuel and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, the unit would be subject to this subpart, as stated in §60.5509a. However, on June 17, 2025, the U.S. Environmental Protection Agency (EPA) proposed to repeal all greenhouse (GHG) emissions standards for fossil fuel-fired power plants, including NSPS TTTTa. The proposed action has not been finalized; therefore, the NSPS TTTTa requirements will be included in the permit. If EPA does finalize the proposed action to repeal these standards, PowerSouth will no longer be subject to the requirements of the rule. The applicable requirements of NSPS TTTTa are discussed below.

As stated in §60.5520a(a) and (b), the CTG would be subject to the CO_2 emission standards specified in Table 1 of the subpart. Table 1 of the subpart lists the CO_2 emission standards for each affected electrical generating unit (EGU) combustion turbine subcategory: base load, intermediate load, and low load. These subcategories are defined in §60.5580a and are included below.

- *Base load combustion turbine* - means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

- *Intermediate load combustion turbine* - means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

- *Low load combustion turbine* - means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

The CO_2 emission standards specified in Table 1 of the subpart are listed in the table below.

Affected EGU Category	CO_2 Emission Standard
Base Load Combustion Turbine	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525a.
Intermediate Load Combustion Turbine	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525a.
Low Load Combustion Turbine	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in §60.5525a.

If the CTG maintains records of the electric sales to demonstrate that the turbine is subject to a heat input-based standard in Table 1 of the subpart (*i.e. low load combustion turbine*), the unit would not be subject to the monitoring or reporting requirements in Subpart TTTTa, as stated in §60.5520a(d)(1), and would only be required to maintain purchase records for natural gas.

If the CTG does not meet the requirements listed in §60.5520a(d)(1), and is subject to an output-based emission standard, the facility must determine the hourly CO_2 mass emissions according to §60.5535a(c)(1) through (4). The facility should also install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, as required by §60.5535a(d)(1).

The facility is required to keep the records listed in §60.5560a. The records are summarized below:

- Recordkeeping requirements of 40 CFR Part 75, Subpart F.
- Calculations used to determine the hourly and total CO_2 emissions (tons) for each operating month and each 12-operating-month compliance period.
- Data and calculations to determine the EGU's gross or net energy output for each operating month.
- Calculations to determine the percentage of valid CO_2 mass emission rates in each compliance period.
- Calculations used to assess compliance with the applicable emission standard listed in Table 1 of this subpart.
- Calculations performed to determine any site-specific carbon based F-factors used in the calculations.
- Records of electric sales to determine the applicable subcategory listed in Table 1 of this subpart.

These records must be maintained for a period of 5 years and must be in a form suitable and readily available for expeditious review, as required by §60.5565a.

The facility must submit the notification specified in §60.7(a)(1), (3), §60.19, and §75.61, as applicable, as required by §60.5550a(a) and (b). Unless the unit meets the requirements of §60.5520a(d)(1), the facility must submit quarterly reports no later than 30 days after the end of each calendar quarter to demonstrate initial and on-going compliance determinations for a 12-operating-month rolling average basis, as stated in §60.5555a(a)(1). The quarterly reports must include the information listed in §60.5555a(a)(2), as applicable, and the final quarterly report for each calendar year must include the information in §60.5555a(3). The procedures in §60.5540a must be followed to determine excess emissions. Since the CTG is also subject to the Acid Rain Program, the facility must meet the reporting requirements described in §60.5555a(c)(1) and begin submitting the quarterly reports according to the requirements of §60.5555a(c)(3)(i). The reports shall be submitted by a person meeting the requirements of §60.5555a(d).

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

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

The Department reviewed 40 CFR Part 63, Subpart UUUUU (*NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units*) for potential applicability. This subpart establishes national emission limitations and work practice standards for HAP emissions emitted from coal- and oil-fired electric utility steam generating units (EGUs). Since the proposed CTG would not meet the definition of coal-fired EGU or oil-fired EGU as defined in §63.10042, the unit would not be subject to this subpart.

40 CFR Part 63, Subpart YYYY – "NESHAP for Stationary Combustion Turbines"

The Department reviewed 40 CFR Part 63, Subpart YYYY (*NESHAP for Stationary Combustion Turbines*) for potential applicability. This subpart applies to HAP emissions from stationary combustion turbines located at major sources of HAP emissions. PowerSouth would remain classified as an area source with respect to HAP emissions following the proposed project. Therefore, the CTG would not be subject to this subpart.

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

The Department reviewed 40 CFR Part 63, Subpart DDDDD (*NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*) for potential applicability. This subpart applies to industrial, commercial, or institutional boilers or process heaters that are located at, or are a part of, a major source of HAP emissions. PowerSouth would remain classified as an area source with respect to HAP emissions following the proposed project. Therefore, the fuel heater would not be subject to this subpart.

40 CFR Part 63, Subpart JJJJJJ – "NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources"

The Department reviewed 40 CFR Part 63, Subpart JJJJJJ (*NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources*) for potential applicability. This subpart applies to industrial, commercial, or institutional boilers that are located at, or are part of, an area source of HAP emissions. The proposed CTG would not heat water to recover thermal energy in the form of steam so the unit would not meet the definition of a *boiler*, as defined in §63.11237. The primary purpose of the proposed fuel heater would be to transfer heat indirectly to a process material for use in the CTG so the fuel heater would

meet the definition of a *process heater* and would be excluded from the definition of a *boiler*, as defined in §63.11237. Therefore, neither proposed unit would be subject to this subpart.

COMPLIANCE ASSURANCE MONITORING (40 CFR PART 64)

The CTG and fuel heater were evaluated for compliance assurance monitoring (CAM) applicability. An emission source is subject to CAM if that unit is subject to a non-exempt emission limitation or standard for a given regulated air pollutant, uses a control device to achieve compliance with that standard for that pollutant, and the uncontrolled potential emission rate for that pollutant is greater than the major-source threshold to attain a Part 70 (Title V) permit.

The fuel heater would be subject to non-exempt emission limitations, but the unit would not be equipped with add-on control devices to achieve compliance with the limitations. Furthermore, the uncontrolled potential emission rate for all pollutants from the fuel heater would be below the major source threshold to attain a Part 70 (Title V) permit. Therefore, the unit would not be subject to CAM. It is noted that the LNB would be considered a passive control measure that acts to prevent pollutants from forming and would not be considered a control device according to the definition in §64.1.

The uncontrolled potential NO_x, CO, VOC, and PM (filterable and condensable) emission rates from the CTG would be greater than the major-source threshold to attain a Part 70 (Title V) permit. The unit would also be subject to non-exempt emission limitations for the aforementioned pollutants and would utilize control device technology to achieve compliance with the some of the emission limitations. The facility would use an oxidation catalyst to achieve compliance with the applicable CO and VOC emission limitations. To achieve compliance with the NO_x emission limitations, the facility would use a SCR and has proposed to install a CEMS. The requirement to install and maintain a CEMS to monitor the NO_x emissions would meet the exemption listed in §64.2(b)(1)(vi), and the CTG would not be subject to CAM for NO_x. The CTG will not be equipped with any add-on control device to achieve compliance with the total PM ($PM/PM_{10}/PM_{2.5}$) emission limitation. Therefore, the CTG would only be subject to CAM for CO and VOC.

The facility has proposed to continuously monitor the oxidation catalyst bed inlet temperature and the pressure differential across the catalyst bed to ensure ongoing and reasonable assurance of compliance with the CO and VOC emission limitations. The facility shall submit a formal CAM plan containing the information required by §64.4 as part of the Title V significant modification application that must be submitted within one year of startup of the new units or as part of next Title V renewal application, whichever is sooner, as referenced by §64.5(a).

MANDATORY GREENHOUSE GAS REPORTING (40 CFR PART 98)

The Mandatory Greenhouse Gas Reporting (40 CFR Part 98) establishes monitoring, recordkeeping, and reporting requirements for the owners and operators of certain facilities that directly emit GHG, as listed in 40 CFR Part 98, Subpart A (*General Provision*). The facility would be subject to the applicable regulations in 40 CFR Part 98, Subpart C (*General Stationary Fuel Combustion Sources*) and 40 CFR Part 98, Subpart D (*Electricity Generation*). Note: On September 12, 2025, EPA proposed to permanently remove program obligations for 46 source categories, including electricity generation, of the Greenhouse Gas Reporting Program. If for any reason, the requirements of the Greenhouse Gas Reporting Program are no longer effective, such as a stay of regulations, the Permittee will no longer be subject to the requirements of the rule.

RECOMMENDATION

Based on the above analysis, upon receiving permitting fees and following resolution of any comments received during the 30-day public comment period, I recommend the following Air Permits be issued with the attached provisos (see Attachment No. 2):

108-0001-X008	Unit 3 Simple Cycle Combustion Turbine with Selective Catalytic Reduction (SCR) and Oxidation Catalyst (nominally rated at 454 MW and 4,048 MMBtu/hr)
108-0001-X009	Natural Gas Fuel Heater for Unit 3 (rated at 9.9 MMBtu/hr)

Stephanie Dubay
Industrial Minerals Section
Energy Branch
Air Division

April 6, 2026
Date

ATTACHMENT NO. 1

Air Quality Analysis

Edward F. Poolos
Director

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Kay Ivey
Governor

October 29, 2025

MEMORANDUM

TO: Stephanie Dubay
Industrial Minerals Section
Energy Branch
Air Division

FROM: Michael Leach
Dallas Roebling
Meteorological Section
Planning Branch
Air Division

SUBJECT: Air Dispersion Modeling of proposed new sources at the PowerSouth Charles R. Lowman Energy Center in Washington County, Alabama.

ADEM has completed its review of an air quality modeling analysis performed by ALL4, Inc and the PowerSouth Energy Cooperative (PowerSouth) on behalf of the Lowman Energy Center (LEC). PowerSouth LEC proposes to construct and operate a natural gas fired combustion turbine generator (CTG), Unit 3, and one new natural gas fuel heater at their existing facility in Leroy, Alabama. The purpose of this analysis was to assess the impacts on air quality from emissions of carbon monoxide (CO), nitrogen dioxide (NO_2), particular matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), and particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}) from the proposed new sources. An air quality analysis was performed for CO, NO_2, $PM_{2.5}$, and PM_{10}, to demonstrate that emissions from the proposed new sources will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD Increment.

AIR QUALITY MODELS:

The American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) was used in default mode for modeling all pollutants. This included the use of the NO_2 Tier 2 Ambient Ratio Method 2 (ARM2) as a default option when modeling NO_2.

METEOROLOGICAL DATA:

Surface and upper air meteorological data for the years 2019-2023 were used in all modeling. The dataset consisted of five years of surface National Weather Service meteorological data from the Mobile Regional Airport (WBAN = 13894, CALL ID = KMOB), located approximately 95 km south of the Facility and National Weather Service upper air data from Slidell Municipal Airport (WBAN =53813, WMO = 72233) near New Orleans, Louisiana.

GOOD ENGINEERING PRACTICE ANALYSIS:

A Good Engineering Practice (GEP) Analysis was performed to assess possible building downwash effects. It was determined that all the stacks that were modeled are within the influence area (5L) of one or more of the controlling buildings and have heights less than the GEP stack height. Therefore, building downwash was considered for those sources in the modeling.

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. The Ozone precursors are the pollutants VOC and NO_x, and the precursor emissions of interest for secondary $PM_{2.5}$ are NO_x and SO_2. For secondary $PM_{2.5}$, the following total emissions were considered: for NO_x, 366.18 TPY; and for SO_2, 38.35 TPY. For Ozone, the following total emissions were considered: for VOC, 115.30 TPY; and for NO_x, 366.18 TPY. The results for the MERPs analyses are presented in Table 1.

TABLE 1
MERPs Analyses Results

Pollutant	Results
Secondary $PM_{2.5}$ (Daily)	3.06E-01 µg/m3
Secondary $PM_{2.5}$ (Annual)	0.010 µg/m3
Ozone	1.93 ppb

The secondary $PM_{2.5}$ impacts were added to primary $PM_{2.5}$ impacts for Class II screening modeling and compared to the SILs (see TABLE 3). Also, the results show that the MERPs for ozone are above 100%. Since calculated consumption is over 100%, a cumulative analysis was required. A review of regional monitors in the southern Alabama region was necessary to determine if the 193%, or 1.93 ppb (based on the proposed ozone SIL of 1 ppb), were added to the ozone background; that the sum would be less than the ozone NAAQS of 70 ppb. Based on the Chickasaw monitor located in Mobile County, the addition of 1.93 ppb of ozone from the MERPs analysis was added to the Chickasaw monitor's 8-hour design value of 61 ppb (based on 2022-2024 data) giving a total of 62.93 ppb. This is less than the standard of 70 ppb. For the complete MERPs calculations, please see the application.

SCREENING MODELING & PRECONSTRUCTION MONITORING:

Screening modeling was performed for CO, NO_2, $PM_{2.5}$, and PM_{10} at PowerSouth LEC. Appendix A of this memo lists the stack parameters and emission rates for the proposed new sources at PowerSouth LEC that were used in the modeling. A load analysis was performed for the proposed LEC Unit 3 to identify worst-case operational conditions for each pollutant and averaging time. Appendix D of the Permit Application provides tables summarizing the worst-case scenarios for Unit 3.

A Cartesian receptor grid, centered on the PowerSouth Lowman site and extending out to 20 kilometers (km) in all directions was used in the modeling. The receptor grid was generated using the following:

(1.) 50 m spacing along the fence line.
(2.) 100 m spacing from fence line out to 5 km.
(3.) 250 m spacing from 5 km to 8 km.
(4.) 500 m spacing from 8 km to 20 km.

All maximum predicted concentrations for all pollutants for all averaging periods were resolved to within 100-meter receptor spacing. Receptor terrain elevations were generated using the EPA AERMAP program.

Table 2 lists the results of screening modeling performed for CO, NO_2, and PM_{10}. Table 3 lists the results of screening modeling performed for $PM_{2.5}$, including secondary concentrations.

TABLE 2
CO, NO_2, and PM_{10} Screening Modeling Results

Pollutant	Averaging Period	Max Conc. ($\mu g/m^3$)	Signif. Level ($\mu g/m^3$)	SIA (km)
CO	1 hour	15.1[(a)]	2000	-
CO	8 hour	7.85[(a)]	500	-
NO_2	1 hour	3.65[(b)]	7.5	-
NO_2	Annual	0.08[(c)]	1	-
PM_{10}	24 hour	0.67[(a)]	5	-
PM_{10}	Annual	0.04[(c)]	1	-

(a) Based on high, first high concentration for all 5 years modeled together.

(b) Based on the five year average high, first high for all 5 years modeled together.

(c) Based on the maximum annual concentration for all 5 years modeled separately.

TABLE 3
$PM_{2.5}$ Screening Modeling Results

Averaging Period	Primary Concentration ($\mu g/m^3$)	Secondary Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)	SIA (km)
24 hour	0.43[(a)]	0.31	0.74	1.2	-
Annual	0.04[(a)]	0.01	0.05	0.13	-

(a) Based on the five year average high, first high for all 5 years modeled together.

Results of the modeling indicated that the maximum predicted concentrations for all pollutants for all averaging periods were below their respective significance levels. Therefore, further modeling was not required.

Also, during this initial screening modeling analysis, preconstruction monitoring requirements were addressed, and it was determined that preconstruction monitoring for all pollutants was not required.

CLASS I AREA MODELING:

The nearest Class I area to PowerSouth is the Breton National Wildlife Refuge (located 182 km south-southwest from PowerSouth LEC). ADEM did not require a Class I Increment analysis and Fish and Wildlife did not require a Class I AQRV analysis based on information that was provided to Jaron Ming and Tim Allen at Fish and Wildlife.

CONCLUSION:

In conclusion, emissions of CO, NO_2, $PM_{2.5}$, and PM_{10} from the proposed new sources at the PowerSouth LEC facility in Leroy, Alabama, are not expected to cause or contribute to a violation of a NAAQS or Class II Increment.

Appendix A
Table 1

Summary of Physical Stack Characteristics

Source	Case Number	Gas Turbine Load	Ambient Temperature	UTM Easting	UTM Northing	Base Elevation	Stack Height	Stack Temperature	Stack Velocity	Stack Diameter	Stack Orientation
		%	°F	(m)	(m)	(m)	(m)	(K)	(m/s)	(m)	
LEC Unit 3	1	100	59	413,538.20	3,484,120.77	13.50	54.86	701.87	27.28	11.07	Vertical
	2	100	95					707.82	26.56		
	3	100	107					709.54	25.99		
	4	100	10					688.21	26.46		
	5	100	20					689.87	26.95		
	6	100	59					701.65	27.25		
	7	100	95					701.71	25.11		
	8	100	107					696.21	24.12		
	9	77	10					662.54	23.28		
	10	77	20					666.15	23.69		
	11	76	59					674.71	23.27		
	12	81	95					683.04	22.67		
	13	84	107					685.87	22.21		
	14	51	10					650.59	19.63		
	15	51	20					656.43	19.98		
	16	51	59					666.98	20.24		
	17	59	95					677.04	20.52		
	18	62	107					674.82	20.10		
	19	43	10					656.15	22.45		
	20	41	20					659.37	22.50		
	21	35	59					667.37	22.13		
	22	44	95					684.82	23.03		
	23	49	107					686.65	22.94		
Fuel Gas Heater	N/A	N/A	N/A	413,702.00	3,484,477.00	12.19	6.10	533.15	4.88	0.66	Capped

Table 1 Continued

Source	Case Number	Gas Turbine Load	Ambient Temperature	NO_X Emissions	$PM/PM_{10}/PM_{2.5}$ Emissions	CO Emissions
		%	°F	lb/hr	lb/hr	lb/hr
LEC Unit 3	1	100	59	80.0	23.1	20.0
	2	100	95	76.0	21.8	19.0
	3	100	107	74.0	21.0	18.0
	4	100	10	80.0	23.0	20.0
	5	100	20	82.0	23.5	20.0
	6	100	59	80.0	23.0	20.0
	7	100	95	70.0	20.0	17.0
	8	100	107	64.0	18.6	16.0
	9	77	10	66.0	19.1	16.0
	10	77	20	66.0	19.5	16.0
	11	76	59	64.0	18.5	16.0
	12	81	95	58.0	17.1	15.0
	13	84	107	56.0	16.4	14.0
	14	51	10	50.0	14.4	12.0
	15	51	20	50.0	14.6	13.0
	16	51	59	50.0	14.4	12.0
	17	59	95	48.0	14.2	12.0
	18	62	107	46.0	13.6	12.0
	19	43	10	52.0	16.1	13.0
	20	41	20	50.0	16.0	13.0
	21	35	59	48.0	14.9	12.0
	22	44	95	48.0	15.2	12.0
	23	49	107	48.0	15.1	12.0
Fuel Gas Heater	N/A	N/A	N/A	1.20E-01	5.76E-02	4.44E-01

ATTACHMENT NO. 2

Proposed Permit Provisos

Alabama Department of Environmental Management

AIR PERMIT

PERMITTEE: POWERSOUTH ENERGY COOPERATIVE

FACILITY NAME: CHARLES R. LOWMAN POWER PLANT

LOCATION: LEROY, WASHINGTON COUNTY, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE
108-0001-X008	Unit 3 Simple Cycle Combustion Turbine with Selective Catalytic Reduction (SCR) and Oxidation Catalyst (nominally rated at 454 MW and 4,048 MMBtu/hr)

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: DRAFT

Alabama Department of Environmental Management

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. 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.

5. 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.

6. All air pollution control equipment shall be operated at all times while this process is operational. In the event of scheduled maintenance, unscheduled maintenance, or a breakdown of the pollution control equipment, the process shall be shut down as expeditiously as possible (unless this act and subsequent re-start would clearly cause greater emissions than continuing operations of the process for a short period). The Department shall be notified of all such events **that exceed 1 hour** within 24 hours. The notification shall include all pertinent facts, including the duration of the process operating without the control device and the level of excess emissions which have occurred. Records of all such events, regardless of reporting requirements, shall be made and maintained for a period of five years. These records shall be available for inspection.

7. 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.

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 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 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. 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. Unless otherwise stated in this permit or an applicable regulation, all performance test results are to be reported to the Air Division within 30 days of completion of testing.

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

14. Emissions tests are to be conducted for the following pollutants at intervals not to exceed 60 months following the date of initial compliance testing. Unless otherwise stated in this permit or an applicable regulation, all performance test reports must be submitted to the Air Division within 30 days of completion of testing.

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

15. Unless otherwise stated in this permit or an applicable regulation, 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.

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. 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.

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. Precautions shall be taken by the Permittee and its personnel to ensure that no person shall ignite, cause to be ignited, permit to be ignited, or maintain any open fire in such a manner as to cause the Department's rules and regulations applicable to open burning to be violated.

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 submit an annual compliance certification to the Department by March 1, covering the reporting period of January 1 through December 31 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:

(1) The identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) 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);

(4) Whether compliance has been continuous or intermittent; and

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

(b) The compliance certification shall contain certification by a responsible official of truth, accuracy and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

Federally Enforceable Provisos	Regulations
Applicability	
1. This unit is 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. This unit is 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. This unit 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. This unit 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. This unit is subject to the applicable provisions of the Cross-State Air Pollution rule (CSAPR) 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.	Rule 335-3-5-.06 through 335-3-5-.36 and 335-3-8-.07 through 335-3-8-.70
6. This unit has enforceable limits in order to comply 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 (PSD/BACT)
7. This unit 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)
8. This unit is subject to the applicable requirements of 40 CFR Part 60, Subpart KKKKa, "Standards of Performance for Stationary Combustion Turbines".	40 CFR 60.4305a(a)
9. This unit is subject to the applicable requirements of 40 CFR Part 60, Subpart TTTTa, "Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units". If for any reason, the requirements of this subpart are no longer effective, such as a stay of regulations, the Permittee will no longer be subject to the requirements of the rule.	40 CFR 60.5509a(a)
10. This unit has enforceable limit in order to prevent it from being classified as a major source with respect to hazardous air pollutant emissions as defined in ADEM Admin. Code r. 335-3-16-.01(1)(q)1.(i).	Rule 335-3-16-.03(1)(a) Rule 335-3-16-.02(8) 40 CFR 63.2 (Anti-MACT)

Federally Enforceable Provisos	Regulations
11. 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
12. This unit is subject to the applicable requirements of ADEM Admin. Code r. 335-3-18, "Acid Rain Program" and 40 CFR Parts 72, 73, and 75.	Rule 335-3-18 40 CFR Parts 72, 73, 75
13. This unit is subject to the applicable provisions of 40 CFR Part 98, "Mandatory Greenhouse Gas Reporting". If for any reason, the requirements of the Greenhouse Gas Reporting Program are no longer effective, such as a stay of regulations, the Permittee will no longer be subject to the requirements of the rule.	40 CFR Part 98
Emission Standards	
1. This unit shall not emit particulate of an opacity greater than twenty percent (20%), as determined by a six-minute average except that, during one six-minute period in any sixty-minute period, the source may emit particulate of an opacity not greater than forty percent (40%).	Rule 335-3-4-.01(1)
2. Filterable particulate matter (PM) emissions from this unit shall not exceed 0.12 lb/MMBtu.	Rule 335-3-4-.03(1) Table 4-1
3. Sulfur dioxide (SO_2) emissions from this unit shall not exceed 4.0 lb/MMbtu.	Rule 335-3-5-.01(1)(b)
4. Nitrogen oxide (NO_x) emissions from this unit shall not exceed 5 ppmvd at 15% O_2 and 82 lb/hr. Compliance is based on a 3-hour rolling average as determined by CEMS.	Rule 335-3-14-.04 (PSD/BACT)
(a) Exceptions to Emission Standards Proviso 4 are granted for startup, shutdown, and load change (as defined below). The permittee shall take all reasonable actions to minimize the magnitude and duration of emissions during the periods listed below.	Rule 335-3-14-.03(1)(h)
(i) Startup – The period from when the combustion turbine is started until the turbine meets the last Department approved minimum load. The Department must approve in writing any change to the startup point prior to modifying such point.	
(ii) Shutdown – The period of time the combustion turbine is decreased from the last approved minimum load to 0% load due to the initiation of shutdown or due to a failure of the unit.	

Federally Enforceable Provisos	**Regulations**
(iii) Load Change – A change in heat input creates a transient operating condition that is readily identifiable on the load chart recording.	
5. Carbon monoxide (CO) emissions from this unit shall not exceed 2 ppmvd at 15% O_2 and 20 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
6. Volatile organic compound (VOC) emissions from this unit shall not exceed 1 ppmvd at 15% O_2 and 6 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
7. Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions (filterable and condensable) from this unit shall not exceed 0.00585 lb/MMBtu and 24 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
8. Greenhouse gas (GHG) emissions from this unit shall not exceed 120 lb CO_2/MMBtu.	Rule 335-3-14-.04 (PSD/BACT)
9. This unit shall only combust natural gas.	Rule 335-3-14-.04 (PSD/BACT)
10. The natural gas fired in this unit shall not exceed a sulfur content of 0.8 gr S/100 scf.	Rule 335-3-14-.04 (PSD/BACT)
11. An oxidation catalyst shall be installed and continuously operated on this unit.	Rule 335-3-14-.04 (PSD/BACT)
12. A selective catalytic reduction (SCR) system and dry low-NO_x combustors shall be installed and continuously operated on this unit.	Rule 335-3-14-.04 (PSD/BACT)
13. This unit shall utilize good design, operating, and combustion practices.	Rule 335-3-14-.04 (PSD/BACT)
14. Hazardous air pollutant (HAP) emissions from the facility shall not exceed 9.5 tons for any individual HAP and shall not exceed 24.5 tons for total HAP emissions during any rolling 12-month period.	Rule 335-3-16-.01(1)(q) Rule 335-3-16-.02(8) 40 CFR 63.2 (Anti-MACT)
15. Nitrogen oxide (NO_x) emissions from this unit shall not exceed the following emission limits, as applicable. Compliance is based on a 4-hour rolling average as determined by CEMS.	40 CFR 60.4320a(b)(3)

High-Utilization Source:	5 ppm at 15% O_2
Low-Utilization Source:	25 ppm at 15% O_2
Operating at less than 70% of the base load rating:	96 ppm at 15% O_2

Federally Enforceable Provisos	Regulations

(a) The Permittee shall determine the source designation of this unit using the following definitions:

High-Utilization Source:	a stationary combustion source with a 12-calendar-month capacity factor greater than 45%.
Low-Utilization Source:	a stationary combustion turbine with a 12-calendar-month capacity factor less than or equal to 45%.
Base Load Rating:	100% of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel.

16. The Permittee must not burn any fuel in this unit which contains total potential sulfur emissions in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output or 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. — 40 CFR 60.4330a(a)

17. Carbon dioxide (CO_2) emissions from this unit shall be limited to the applicable gross or net energy output standard listed below: — 40 CFR 60.5520a(a) and (b)

Base load combustion turbines:	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output
Intermediate load combustion turbines:	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output
Low load combustion turbines:	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input

(a) The Permittee shall determine the gross and net energy output using the procedures in 40 CFR 60.5525a.

Federally Enforceable Provisos	Regulations

(b) The Permittee shall determine the affected electrical generation unit (EGU) category of this unit using the following definitions:

Base load combustion turbines:	a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.
Intermediate load combustion turbines:	a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.
Low load combustion turbines:	a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

18. 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)

Compliance and Performance Test Methods and Procedures

1. Compliance with the opacity standard in Emission Standards Proviso 1 shall be determined by EPA Reference Method 9 in 40 CFR Part 60, Appendix A-4. — Rule 335-3-1-.05(1)
2. Compliance with the particulate matter (PM) emission limitation in Emission Standards Proviso 2 shall be determined by EPA Reference Method 5 in 40 CFR Part 60, Appendix 3 or Method 17 in 40 CFR Part 60, Appendix A-6. — Rule 335-3-1-.05(1)
3. Compliance with the particulate matter ($PM/PM_{10}/PM_{2.5}$) emission limitation in Emission Standards Proviso 7 shall be determined by EPA Reference Method 202 in 40 CFR Part 51, Appendix M, and Method 5 in 40 CFR Part 60, Appendix 3, Method 17 in 40 CFR Part 60, Appendix A-6, or Method 201A in 40 CFR Part 51, Appendix M. — Rule 335-3-1-.05(1)
4. Compliance with the sulfur dioxide (SO_2) and natural gas sulfur content requirements in Emission Standards Provisos 3, 10, and 16, shall be determined by representative fuel sampling following procedures specified in section 2.3.1.4 or 2.3.2.4 of 40 CFR Part 75, Appendix D. However, should testing be required, EPA Reference Method 6 or 6C in 40 CFR Part 60, Appendix A-4 or Method 20 in 40 CFR Part 60, Appendix A-7 shall be used. — 40 CFR 60.4372a(e)

Federally Enforceable Provisos	Regulations
5. Compliance with the nitrogen oxide (NO_x) emission limitations in Emission Standards Provisos 4 and 15 shall be determined using a NO_x diluent CEMS that is installed, operated, maintained, and certified according to 40 CFR Part 75, Appendix A. However, should testing be required, EPA Reference Method 7 or 7E in 40 CFR Part 60, Appendix A-4 shall be used.	Rule 335-3-1-.05(1) Rule 335-3-14-.04 (PSD/BACT) 40 CFR 60.4345a(a)
6. Compliance with the carbon monoxide (CO) emission limitation in Emission Standards Proviso 5 shall be determined by EPA Reference Method 10 in 40 CFR Part 60, Appendix A-4.	Rule 335-3-1-.05(1)
7. Compliance with the volatile organic compound (VOC) emission limitation in Emission Standards Proviso 6 shall be determined by EPA Reference Method 25, 25A, or 25B in 40 CFR Part 60, Appendix A-7.	Rule 335-3-1-.05(1)
8. Compliance with greenhouse gas (GHG) and fuel usage emission limitations in Emission Standards Provisos 8 and 9 shall be determined using fuel purchase records.	Rule 335-3-1-.04(1)
9. Compliance with the carbon dioxide (CO_2) emission limitations in Emission Standards Proviso 17 shall be determined as follows:	40 CFR 60.5540a
(a) Energy output-based standards shall be determined as specified in 40 CFR 60.5525a and 40 CFR 60.5540a.	
(b) Heat input based standards shall be determined with fuel purchase records.	40 CFR 60.5520a(d)
10. Compliance with the hazardous air pollutant (HAP) emission limitation in Emission Standards Proviso 14 shall be determined by calculating the facility-wide HAP emissions on a monthly and rolling 12-month basis.	Rule 335-3-1-.04(1)
(a) The Permittee shall calculate the HAP emissions from the units using the approved emission factors located in the application submitted on February 16, 2026. Any changes to the emission factors must be approved by the Department.	
11. Any performance tests required shall be conducted and data recorded in accordance with the test methods and procedures contained in each specific permit condition and in accordance with General Permit Provisos 13, 14, 15, and 16. Additionally:	Rule 335-3-1-.04(1)

Federally Enforceable Provisos	Regulations
(a) Performance tests shall be conducted under such conditions as the Department specifies to the Permittee based on representative performance of this unit for the period being tested.	
(b) Each performance test must consist of three (3) separate runs; pollutant sampling for each run must be conducted for the time period specified in the applicable method or, in the absence of a specific time period in the test method, for a minimum of one (1) hour.	
Emissions Monitoring	
1. A continuous emissions monitoring system (CEMS) to measure nitrogen oxide (NO_x) emissions shall be installed and operated at a location approved by the Director. The CEMS shall meet the specifications and procedures of 40 CFR Part 75 and will be certified and maintained in accordance with 40 CFR Part 75. Additionally, the CEMS shall meet the requirements of 40 CFR 60.4345a.	Rule 335-3-14-.04 (PSD/BACT) 40 CFR 60.4345a
2. The initial testing requirements of the NO_x diluent CEMS are listed in 40 CFR 60.4405a(b)(1) through (4). This testing requirement is also applicable to the initial testing requirement required by General Permit Proviso 13.	40 CFR 60.4405a
3. If this unit is determined to be a base load or intermediate load combustion turbine, as defined in Emission Standards Proviso 17(b), the Permittee must perform the following:	
(a) Prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The plan must be in place prior to reporting emissions data and must be updated as necessary.	40 CFR 60.5535a(a)
(b) Determine the hourly CO_2 mass emissions according to 40 CFR 60.5535a(c)(1) through (4)	40 CFR 60.5535a(c)(1) through (4)
(c) Install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable.	40 CFR 60.5535a(d)(1)
4. The Permittee must continuously monitor the pressure differential across the oxidation catalyst bed, which shall be maintained within the range suggested by the catalyst manufacturer.	Rule 335-3-1-.04(1)

Federally Enforceable Provisos	Regulations
5. The Permittee must continuously monitor the inlet temperature of the oxidation catalyst bed, which shall be maintained within the range suggested by the catalyst manufacturer.	Rule 335-3-1-.04(1)
6. The facility shall calculate the facility-wide HAP emissions on a monthly basis. The facility-wide monthly HAP emissions must be utilized to calculate a rolling 12-month total.	Rule 335-3-16-.05(c)1.
Recordkeeping and Reporting	
1. All records shall be maintained in a form suitable for inspection for a period of at least five years following the date of record generation. All records shall be made available upon request.	Rule 335-3-16-.05(c)
2. The Permittee shall provide the Department at least 30 days prior notice of the performance tests required by Emission Monitoring Provisos 2 and 3. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the Permittee shall notify the Department as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Department by mutual agreement.	Rule 335-3-10-.02(1) 40 CFR 60.8(d)
3. The Permittee must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). The report must be submitted by the 30th day following the end of each 6-month period. Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. Periods of excess emissions and monitor downtime are defined in 40 CFR 60.4380a(b).	40 CFR 60.4375a(a) 40 CFR 60.4380a(b) 40 CFR 60.4395a
(a) The Permittee must utilize the procedures located in 40 CFR 60.4350a(a) through (e), (f)(1), and (g) to identify excess emissions from the NO_x diluent CEMS.	40 CFR 60.4350a
(i) Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).	40 CFR 60.4350a(d)
4. The Permittee must maintain purchase records for natural gas and results of all fuel analyses.	Rule 335-3-14-.04 PSD/BACT 40 CFR 60.4390a(f) 40 CFR 60.5520a(d)

Federally Enforceable Provisos	Regulations
5. The Permittee must submit the notification specified in 40 CFR 60.7(a)(1), (3), 40 CFR 60.19, and 40 CFR 75.61, as applicable.	40 CFR 60.5550a(a) 40 CFR 60.5550a(b)
6. If this unit is determined to be a base load or intermediate load combustion turbine, as defined in Emission Standards Proviso 17(b), the Permittee must meet the following:	
(a) Submit quarterly reports for initial and on-going compliance determinations on a 12-operating-month rolling average basis. The reports must be submitted no later than 30 days after the end of each calendar quarter. The reports should contain the information in 40 CFR 60.5555a(a)(2), as applicable. The final quarterly report for each calendar year must include the information in 40 CFR 60.5555a(a)(3).	40 CFR 60.5555a(a)(1) through (3)
(b) All applicable reporting requirements and submit reports as required under 40 CFR Part 75, Subpart G. The reports must be submitted quarterly in accordance with 40 CFR 75.64(a). The reports shall be submitted by a person meeting the requirements of 40 CFR 60.5555a(d).	40 CFR 60.5555a(c)(1) 40 CFR 60.5555a(c)(3)(i) 40 CFR 60.5555a(d)
7. The Permittee must maintain the following records in accordance with the requirements of 40 CFR Part 60, Subpart TTTTa.	40 CFR 60.5560a 40 CFR 60.5565a
(a) Recordkeeping requirements listed in 40 CFR Part 75, Subpart F.	40 CFR 60.5560a(b)(1)
(b) Records of the calculations used to determine the hourly and total CO2 mass emissions (tons) for:	40 CFR 60.5560a(c)
(iv) Each operating month; and	40 CFR 60.5560a(c)(1)
(v) Each compliance period, including, each 12-operating-month compliance period.	40 CFR 60.5560a(c)(2)
(c) Records of the applicable data recorded and calculations performed to determine the EGU's gross or net energy output for each operating month.	40 CFR 60.5560a(d)
(d) Records of the calculation performed to determine the percentage of valid CO2 mass emission rates in each compliance period.	40 CFR 60.5560a(e)
(e) Records of the calculations performed to assess compliance with each applicable CO2 mass emissions standard in Emission Standards Proviso 17.	40 CFR 60.5560a(f)

Federally Enforceable Provisos	Regulations
(f) Records of the calculations performed to determine any site-specific carbon based F-factors used in the emission calculations.	40 CFR 60.5560a(g)
(g) Records of electric sales to determine the applicable subcategory as defined in Emission Standards Proviso 17(b).	40 CFR 60.5560a(h)
8. The Permittee shall maintain records of the pressure differential across the oxidation catalyst bed.	Rule 335-3-1-.04(1)
9. The Permittee shall maintain records of the inlet temperature of the oxidation catalyst bed.	Rule 335-3-1-.04(1)
10. 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.	Rule 335-3-5-.31 335-3-5-.35 335-3-8-.33 335-3-8-.37 335-3-8-.65 335-3-8-.69
11. The Permittee shall submit a report to the Department within 60 days after the end of each year containing the following information for sulfur dioxide (SO_2) emissions: (a) All information required by ADEM Admin. Code r. 335-3-14-.04(17)(e)1. (b) The name, address and telephone number of the major stationary source; (c) The annual emissions as calculated pursuant to ADEM Admin. Code r. 335-3-14-.04(17)(e)3.; and (d) Any other information that the owner or operator wishes to include in the report.	Rule 335-3-14-.04(17)(e)4.
12. The Permittee shall maintain records of the amount of HAPs emitted on a calendar month basis and on a rolling 12-month basis.	Rule 335-3-16-.05(c)
13. The Permittee shall submit a complete Acid Rain permit application at least 24 months before the date on which the unit commences operation.	Rule 335-3-18 40 CFR Parts 72, 73, 75 40 CFR 72.30(b)(2)(ii)
14. The Permittee shall submit a formal Compliance Assurance Monitoring (CAM) plan for the oxidation catalyst containing the information required by 40 CFR 64.4 as part of the significant modification application that must be submitted within one year of startup of this unit or as part of the next Title V renewal application, whichever is sooner.	40 CFR Part 64 40 CFR 64.5(a)

AIR PERMIT

PERMITTEE: POWERSOUTH ENERGY COOPERATIVE

FACILITY NAME: CHARLES R. LOWMAN POWER PLANT

LOCATION: LEROY, WASHINGTON COUNTY, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE
108-0001-X009	Natural Gas Fuel Heater for Unit 3 (rated at 9.9 MMBtu/hr)

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: DRAFT

Alabama Department of Environmental Management

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. 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.

5. 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.

6. All air pollution control equipment shall be operated at all times while this process is operational. In the event of scheduled maintenance, unscheduled maintenance, or a breakdown of the pollution control equipment, the process shall be shut down as expeditiously as possible (unless this act and subsequent re-start would clearly cause greater emissions than continuing operations of the process for a short period). The Department shall be notified of all such events **that exceed 1 hour** within 24 hours. The notification shall include all pertinent facts, including the duration of the process operating without the control device and the level of excess emissions which have occurred. Records of all such events, regardless of reporting requirements, shall be made and maintained for a period of five years. These records shall be available for inspection.

7. 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.

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 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 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. Unless otherwise stated in this permit or an applicable regulation, 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.

14. 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.

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. 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.

17. Precautions shall be taken by the Permittee and its personnel to ensure that no person shall ignite, cause to be ignited, permit to be ignited, or maintain any open fire in such a manner as to cause the Department's rules and regulations applicable to open burning to be violated.

18. 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.

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

20. The Permittee shall submit an annual compliance certification to the Department by March 1, covering the reporting period of January 1 through December 31 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:

        (1) The identification of each term or condition of this permit that is the basis of the certification;

        (2) The compliance status;

        (3) 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);

        (4) Whether compliance has been continuous or intermittent; and

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

    (b) The compliance certification shall contain certification by a responsible official of truth, accuracy and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

Federally Enforceable Provisos	Regulations
Applicability	
1. This unit is 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. This unit is 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. This unit 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. This unit 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. This unit has enforceable limits in order to comply 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 (PSD/BACT)
6. This unit has an enforceable limit in order to prevent it from being classified as a major source with respect to hazardous air pollutant emissions as defined in ADEM Admin. Code r. 335-3-16-.01(1)(q)1.(i).	Rule 335-3-16-.01(1)(q) Rule 335-3-16-.02(8) 40 CFR 63.2 (Anti-MACT)
7. 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.
8. This unit is subject to the applicable provisions of 40 CFR Part 98, "Mandatory Greenhouse Gas Reporting". If for any reason, the requirements of the Greenhouse Gas Reporting Program are no longer effective, such as a stay of regulations, the Permittee will no longer be subject to the requirements of the rule.	40 CFR Part 98
Emission Standards	
1. This unit shall not emit particulate of an opacity greater than twenty percent (20%), as determined by a six-minute average except that, during one six-minute period in any sixty-minute period, the source may emit particulate of an opacity not greater than forty percent (40%).	Rule 335-3-4-.01(1)
2. Filterable particulate matter (PM) emissions from this unit shall not exceed 0.5 lb/MMBtu	Rule 335-3-4-.03(1) Table 4-1
3. Sulfur dioxide (SO_2) emissions from this unit shall not exceed 4.0 lb/MMbtu.	Rule 335-3-5-.01(1)(b)

Federally Enforceable Provisos	**Regulations**
4. Nitrogen oxide (NO_x) emissions from this unit shall not exceed 0.010 lb/MMBtu and 0.10 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
5. Carbon monoxide (CO) emissions from this unit shall not exceed 0.037 lb/MMBtu and 0.37 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
6. Volatile organic compound (VOC) emissions from this unit shall not exceed 0.005 lb/MMBtu and 0.05 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
7. Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions (filterable and condensable) from this unit shall not exceed 0.0048 lb/MMBtu and 0.05 lb/hr.	Rule 335-3-14-.04 (PSD/BACT)
8. Greenhouse gas (GHG) emissions from this unit shall not exceed 120 CO_2 lb/MMBtu.	Rule 335-3-14-.04 (PSD/BACT)
9. This unit shall only combust natural gas.	Rule 335-3-14-.04 (PSD/BACT)
10. The natural gas fired in this unit shall not exceed a sulfur content of 0.8 gr S/100 scf.	Rule 335-3-14-.04 (PSD/BACT)
11. This unit shall utilize good design, operating, and combustion practices.	Rule 335-3-14-.04 (PSD/BACT)
12. Hazardous air pollutant (HAP) emissions from the facility shall not exceed 9.5 tons for any individual HAP and shall not exceed 24.5 tons for total HAP emissions during any rolling 12-month period.	Rule 335-3-16-.01(1)(q) Rule 335-3-16-.02(8) 40 CFR 63.2 (Anti-MACT)
Compliance and Performance Test Methods and Procedures	
1. Compliance with the opacity standard in Emission Standards Proviso 1 shall be determined by EPA Reference Method 9 in 40 CFR Part 60, Appendix A-4.	Rule 335-3-1-.05(1)
2. Compliance with the particulate matter (PM) emission limitation in Emission Standards Proviso 2 shall be determined by EPA Reference Method 5 in 40 CFR Part 60, Appendix 3, or Method 17 in 40 CFR Part 60, Appendix A-6.	Rule 335-3-1-.05(1)
3. Compliance with the particulate matter ($PM/PM_{10}/PM_{2.5}$) emission limitation in Emission Standards Proviso 7 shall be determined by EPA Reference Method 202 in 40 CFR Part 51, Appendix M, and Method 5 in 40 CFR Part 60, Appendix 3, Method 17 in 40 CFR Part 60, Appendix A-6, or Method 201A in 40 CFR Part 51, Appendix M.	Rule 335-3-1-.05(1)

Federally Enforceable Provisos	Regulations
4. Compliance with the sulfur dioxide (SO_2) and natural gas sulfur content requirements in Emission Standards Provisos 3 and 10, shall be determined by representative fuel sampling following procedures specified in section 2.3.1.4 or 2.3.2.4 of 40 CFR Part 75, Appendix D. However, should testing be required, EPA Reference Method 6 or 6C in 40 CFR Part 60, Appendix A-4 or Method 20 in 40 CFR Part 60, Appendix A-7 shall be used.	Rule 335-3-1-.05(1)
5. Compliance with the nitrogen oxides (NO_x) emission limitation in Emission Standards Proviso 4 shall be determined by EPA Reference Method 7 or 7E in 40 CFR Part 60, Appendix A-4.	Rule 335-3-1-.05(1)
6. Compliance with the carbon monoxide (CO) emission limitation in Emission Standards Proviso 5 shall be determined by EPA Reference Method 10 in 40 CFR Part 60, Appendix A-4.	Rule 335-3-1-.05(1)
7. Compliance with the volatile organic compound (VOC) emission limitation in Emission Standards Proviso 6 shall be determined by EPA Reference Method 25, 25A, or 25B in 40 CFR Part 60, Appendix A-7.	Rule 335-3-1-.05(1)
8. Compliance with greenhouse gas (GHG) and fuel usage emission limitations in Emission Standards Provisos 8 and 9 shall be determined using fuel purchase records.	Rule 335-3-1-.04(1)
9. Compliance with the hazardous air pollutant (HAP) emission limitation in Emission Standards Proviso 12 shall be determined by calculating the facility-wide HAP emissions on a monthly and rolling 12-month basis. (a) The Permittee shall calculate the HAP emissions from the units using the approved emission factors located in the application submitted on February 16, 2026. Any changes to the emission factors must be approved by the Department.	Rule 335-3-1-.04(1)
Emissions Monitoring	
1. The facility shall calculate the facility-wide HAP emissions on a monthly basis. The facility-wide monthly HAP emissions must be utilized to calculate a rolling 12-month total.	Rule 335-3-16-.05(c)1.
Recordkeeping and Reporting	
1. All records shall be maintained in a form suitable for inspection for a period of at least five years following the date of record generation. All records shall be made available upon request.	Rule 335-3-16-.05(c)

Federally Enforceable Provisos	Regulations
2. The Permittee must maintain purchase records for natural gas and results of all fuel analyses.	Rule 335-3-16-.05(c)
3. The Permittee shall maintain records of the amount of HAPs emitted on a calendar month basis and on a rolling 12-month basis.	Rule 335-3-16-.05(c)
4. The Permittee shall comply with the recordkeeping and reporting requirements of the Mandatory Greenhouse Gas Reporting Rule in 40 CFR Part 98.	40 CFR Part 98