Introduction
On February 26, 2021, Tennessee Valley Authority (TVA) submitted an air permit application for a project to take place at the Colbert Plant located at 900 Colbert Steam Plant Road, Tuscumbia, Colbert County, Alabama. Additional information was received on April 5, 2021, April 9, 2021, and April 12, 2021. A revised application incorporating changes and adding additional information was received on June 10, 2021 and further supporting information was received on July 12, 2021. TVA has proposed the addition of three (3) new natural gas-fired simple cycle combustion turbine (CT) generators. Ancillary equipment associated with the proposed project would include three (3) natural gas-fired fuel heaters rated at 10 MMBtu/hr. Each CT unit would be capable of producing a gross output of approximately 229 megawatts (MW) for a project total of 687 MW.

Facility Description
The TVA Colbert facility is an electric power generation facility currently with eight (8) natural gas and oil-fired combustion turbine generating units. The Colbert Plant also operates other smaller sources of air emissions such as an emergency fire pump engine.

PSD
The proposed project would qualify as a major source modification since the emissions of nitrogen oxides (NOₓ), carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM₁₀), particulate matter less than 2.5 microns (PM₂.₅), and greenhouse gas emissions (GHG) would result in a net increase more than the significant emissions rates listed in ADEM Admin. Code r. 335-3-14-.04(1)(w). The proposed project would be subject to ADEM Admin. Code r. 335-3-14-.04 which was adopted pursuant to the federal requirements for prevention of significant deterioration (PSD).

PSD regulations were designed to limit pollutant concentration increases in areas that are cleaner than the National Ambient Air Quality Standards (NAAQS). The regulations establish increments that set ceilings on the amount of increased ambient pollutant concentrations that will be allowed in a PSD area. Sources subject to PSD regulations must comply with specific pre-construction review requirements.
A major source or major modification under a PSD review must be constructed with Best Available Control Technology (BACT). Additionally, the effects on soils, vegetation, visibility, and ambient air quality must be addressed for each applicable pollutant. If the net air emissions increase of any applicable pollutant is less than its significance emission rate, a PSD review is not necessary for that pollutant.

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

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PSD Significant Emission Rate (TPY)</th>
<th>Proposed Net Emission Rate Increase (TPY)</th>
<th>Significant Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter (PM)</td>
<td>25</td>
<td>46.8</td>
<td>YES</td>
</tr>
<tr>
<td>Particulate Matter &lt; 10μ (PM10)</td>
<td>15</td>
<td>93.3</td>
<td>YES</td>
</tr>
<tr>
<td>Particulate Matter &lt; 2.5μ (PM2.5)</td>
<td>10</td>
<td>93.3</td>
<td>YES</td>
</tr>
<tr>
<td>Sulfur Dioxide (SO2)</td>
<td>40</td>
<td>6.9</td>
<td>NO</td>
</tr>
<tr>
<td>Nitrogen Oxides (NOx)</td>
<td>40</td>
<td>380</td>
<td>YES</td>
</tr>
<tr>
<td>Carbon Monoxide (CO)</td>
<td>100</td>
<td>432</td>
<td>YES</td>
</tr>
<tr>
<td>Volatile Organic Compounds (VOC)</td>
<td>40</td>
<td>38.9</td>
<td>NO</td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>0.6</td>
<td>&lt;0.01</td>
<td>NO</td>
</tr>
<tr>
<td>Sulfuric Acid mist (H2SO4)</td>
<td>7</td>
<td>0.5</td>
<td>NO</td>
</tr>
<tr>
<td>Fluorides</td>
<td>3</td>
<td>0</td>
<td>NO</td>
</tr>
<tr>
<td>Total Reduced Sulfur</td>
<td>10</td>
<td>0</td>
<td>NO</td>
</tr>
<tr>
<td>Greenhouse Gases (GHG)(CO2e)</td>
<td>75,000</td>
<td>1,376,480</td>
<td>YES</td>
</tr>
</tbody>
</table>

**BACT**

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

**NO\textsubscript{x}**

NO\textsubscript{x} emissions are generated from fuel combustion and are a result of three (3) formation mechanisms: thermal NO\textsubscript{x} from the dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air, fuel-derived NO\textsubscript{x} from the oxidation of nitrogenous compounds that are present in the fuel, and prompt NO\textsubscript{x} from the oxidation of hydrocarbon radicals near the combustion flame. NO\textsubscript{x} controls typically either control NO\textsubscript{x} emissions by reducing NO\textsubscript{x} formation caused by combustion or reducing NO\textsubscript{x} emissions after their formation via an add on control device.

Controls reducing formation of NO\textsubscript{x} would include water or steam injection, combustor design features such as dry low-NO\textsubscript{x} burners (DLN), and good combustion design and practices (GCDP). NO\textsubscript{x} emission reductions could also be achieved through post-combustion controls such as selective catalytic reduction (SCR) that uses ammonia or urea injected into the exhaust gas steam to react with NO\textsubscript{x} to form nitrogen and water or selective non-catalytic reduction (SNCR) that uses high temperatures and a reducing agent such as ammonia or urea to reduce NO\textsubscript{x} emissions.

**CT Units**

SCR systems, catalytic absorption-and-oxidation (EM\textsuperscript{TM} [SCONO\textsubscript{x}\textsuperscript{TM}]), SNCR systems, dry low NO\textsubscript{x} combustors, and water or steam injection were identified as potential NO\textsubscript{x} reduction technologies. Of these options, DLN and GCDP were identified in RBLC as being applied to natural gas-fired combustion turbines and are widely considered technically feasible NO\textsubscript{x} control options. SNCR systems are not technically feasible since simple cycle CTs do not achieve the appropriate temperatures or residence times for SNCR to be utilized. Water or steam injection was considered technically infeasible since this technology is no longer used on new natural gas only fired simple cycle CTs and hasn’t been for several years. Water or steam injection is no longer utilized due to the superior control efficiency of DLN and increases in CT efficiencies achieved by modern, natural gas combustion systems. A review of RBLC showed that water or steam injection has not be utilized on a new natural gas only CT for several years. While SCR systems are typically seen on new combined cycle units and have not been often utilized for HD/frame simple cycle units like the ones proposed, SCR control was
considered technically feasible and evaluated for economic feasibility. TVA determined that the use of SCR controls on the proposed CTs would result in a cost effectiveness of $20,400 per ton of NOx removed. As a result, SCR controls would not be considered economically feasible. TVA proposes low-NOx burners, good combustion practices (GCDP), and a NOx emission limit of 9 ppmv at 15% O2 for BACT. Additionally, all project sources would be subject to a 380 tons per year limit of NOx based on the PM$_{2.5}$ MERPs analysis.

A review of the RBLC revealed that the proposed control design would provide NOx 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 NOx emissions from the CT units.

**Fuel Heaters**

GCDP and low NOx burners were identified as potential control options for these units. The use of low NOx burners has been demonstrated to meet the top level of demonstrated NOx control for similar units in RBLC. TVA proposes low-NOx burner, GCDP, and a NOx emission rate of 0.011 lb/MMBtu for BACT.

A review of the RBLC revealed that the proposed control design would provide NOx 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 NOx emissions from the fuel heaters.

**CO**

CO emissions result from incomplete combustion of carbonaceous fuels. Temperature and residence time are the primary factors influencing CO formation. The CO emissions from new sources associated with the proposed project are a result of the combustion of natural gas in the CT units and gas heaters.

Oxidation catalysts, absorption-and-oxidation technology, combustion controls/GCDP, and clean fuels were identified as potential control techniques for the control of CO emissions.

**CT Units**

Both oxidation catalysts and absorption-and-oxidation technology were evaluated for technical feasibility. While not identified in RBLC, one catox oxidation system is installed and utilized on a
similar CT in California. This technology is considered technically feasible. EMx (SCONoX) is an absorption-and-oxidation control technology system. EMx (SCONoX) has been applied to smaller CT units, but this system experiences technical issues when scaling up to larger CTs. Reliability issues and little operating experience, in addition to technical challenges and a lack of demonstrated, successful use on similar sized CT units makes this control technology not technically feasible for the proposed CT units. The use of oxidation catalysts was evaluated for economic feasibility. TVA determined that the use of an oxidation catalyst for the proposed CT units would have a cost effectiveness of $10,800 per ton of CO removed. TVA proposes to use of GCDP and DLN to limit CO emissions and a CO emissions limitation of 9 ppmvd @15% O2 and a CO emissions limit of 500 lbs per CT startup event.

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

**Fuel Heaters**

GCDP was identified as a potential control alternative for CO emissions from gas heaters. Therefore, GCDP is the only option considered technically and economically feasible. GCDP is typically identified as periodic burner tune-ups, maintaining optimum combustion efficiency, and implementing appropriate maintenance procedures. TVA proposes GCDP, natural gas firing, and a CO emissions limit of 0.08 lb/MMBtu as BACT.

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

**PM, PM10, PM2.5**

Particulate matter emissions from combustion sources are a combination of filterable and condensable particles. The filterable portion is the result of incomplete combustion and impurities in the fuel, while the condensable portion is the result of formation of sulfates and other compounds.
Clean fuels, GCDP/combustion control, and unit design were identified as potential control technologies for PM emissions from combustion sources.

**CT units**

There are no add-on controls such as an ESP or fabric filter for PM demonstrated on CT units. The top-level demonstrated PM control method for CT units is the use of low ash and low sulfur fuels. Firing of natural gas and proper combustion practices are demonstrated on similar units according to the RBLC and would be considered technically and economically feasible. TVA proposes to the use of natural gas and GCDP with PM emissions limits of 18 lb/hr and 0.008 lb/MMBtu of PM$_{10}$/PM$_{2.5}$ (including filterable and condensable PM) as BACT.

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

**Fuel Heaters**

A review of RBLC was conducted to determine applicable PM control methods for similar units. The use of clean fuels and GCDP were identified as potential controls for PM emissions. Firing of clean fuels and GCDP are demonstrated on similar units according to the RBLC and would be considered technically and economically feasible. TVA proposes the firing of natural gas and GCDP with a PM emissions limit of 0.008 lb/MMBtu of PM$_{10}$ or PM$_{2.5}$ (filterable) as BACT.

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

**GHG (CO$_{2e}$)**

GHG emissions result from the combustion of fuels and include carbon dioxide (CO$_2$), methane (CH$_4$), and nitrous oxide (N$_2$O).
Carbon capture, utilization, and storage (CCUS), energy efficient design, low carbon fuels, and GCDP were identified as available technologies to control GHG emissions.

**CT Units**

The majority of GHG emissions from this unit would be CO\(_2\). TVA evaluated energy efficiency, use of low carbon fuels, and carbon capture and storage as CO\(_2\) emission controls. Energy efficiency and low carbon fuels are considered technically feasible. TVA evaluated technical feasibility for capture and storage and determined that, based on the lack of commercial deployment at similar CT units, carbon capture is technically infeasible for this application. However, TVA still evaluated the economic feasibility of carbon capture and storage for the CTs. TVA calculated an annual cost of $56,000,000 when considering the size of the units. The levelized cost of electricity from CT generation is projected at $54,000,000 per year, making carbon capture and storage economically infeasible. TVA proposes the use of CT energy efficiency designs, GCDP, the use of natural gas, and emissions limitation of 120 lbs CO\(_2e\)/MMBtu as BACT.

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

**Fuel Heaters**

A review of RBLC was conducted to determine applicable GHG control methods for natural gas-fired gas heaters. The use of clean fuels, efficient design, and GCDP were identified as potential controls for GHG emissions. Firing of clean fuels, efficient design, and GCDP are demonstrated on similar units according to the RBLC and would be considered technically and economically feasible. TVA proposes to the firing of clean fuels, efficient design, and GCDP with a GHG emissions limitation of 117.1 lbs CO\(_2e\)/MMBtu as BACT.

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

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

National Ambient Air Quality Standards (NAAQS)

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

<table>
<thead>
<tr>
<th>Pollutant/Averaging Time</th>
<th>Primary Standard</th>
<th>Secondary Standard</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Nitrogen Dioxide</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NO2, annual</td>
<td>53 ppb</td>
<td>53 ppb</td>
</tr>
<tr>
<td>NO2, 1-hour</td>
<td>100 ppb</td>
<td>---</td>
</tr>
<tr>
<td><strong>Carbon Monoxide</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO, 8-hour</td>
<td>9 ppm</td>
<td>---</td>
</tr>
<tr>
<td>CO, 1-hour</td>
<td>35 ppm</td>
<td>---</td>
</tr>
<tr>
<td><strong>Ozone</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O3, 8-hour</td>
<td>0.070 ppm</td>
<td>0.070 ppm</td>
</tr>
<tr>
<td><strong>Particulate Matter</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PM10, 24-hour</td>
<td>150 µg/m³</td>
<td>150 µg/m³</td>
</tr>
<tr>
<td>PM2.5, annual</td>
<td>12.0 µg/m³</td>
<td>15.0 µg/m³</td>
</tr>
<tr>
<td>PM2.5, 24-hour</td>
<td>35 µg/m³</td>
<td>35 µg/m³</td>
</tr>
</tbody>
</table>

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

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

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

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Class I (µg/m³)</th>
<th>Class II (µg/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>Annual</td>
<td>2.5</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td>1-hour</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>CO</td>
<td>8-hour</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td></td>
<td>1-hour</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>Annual</td>
<td>4</td>
<td>17</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>8</td>
<td>30</td>
</tr>
<tr>
<td>PM₂.₅</td>
<td>Annual</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>2</td>
<td>9</td>
</tr>
</tbody>
</table>

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 applications forms submitted document that the closest Class I Area, the Sipsey Wilderness, is within 100 km from the facility. In addition to the Class I increment analysis,
modeling was performed to address deposition of sulfur and nitrogen compounds and impacts on regional haze. Again, Attachment 1 provides a review of the Class I Area analysis. The predicted impacts on regional haze, nitrogen deposition, and sulfur deposition at the Sipsey Wilderness Area are below the levels recommended by the Federal Land Manager (FLM).

Class II Areas:
Class II areas can accommodate normal well-managed industrial growth. TVA Colbert is located in a Class II Area. Attachment No. 1 provides a review of the PSD Class II modeling analysis. As can be seen from the review, there are no predicted violations of the Class II increments 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:

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

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

(b) Soils and Vegetation
As the impacts from the proposed project will be less than all NAAQS, which are intended to protect human health and are more stringent than standards intended to protect soil or vegetation, the project is not expected to have a significant impact on the surrounding soil. Modeled impacts of CO and annual NO\textsubscript{2} are less than the SIL. In summary, the project is not expected to result in significant impact on soil, vegetation, or wildlife in the area surrounding the facility.

**c) Visibility Impairment**

The PSD regulations require that an analysis be performed to assess the impact from the proposed source on visibility relative to any Class I areas. A Class I ambient air quality impact analysis was performed, and the results indicated that visibility would not be impacted beyond the significance threshold.

**Compliance Assurance Monitoring (CAM) and other Monitoring**

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

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

- 10 MMBtu/hr Gas Fuel Boilers (The low NOx burners would not be considered a control device according to the definition in 40 CFR §64.1 since it is considered a passive control measure that acts to prevent pollutants from forming.)
- CT units (The DLN would not be considered a control device according to the definition in 40 CFR §64.1 since it is considered a passive control measure that acts to prevent pollutants from forming.)

The permittee will monitor and keep records of sulfur content of natural gas showing less than 0.15 gr/100 scf to indicate compliance with the PM BACT limit. The 0.15 gr/100 scf value is based on the CT manufacturer information for complying with the PM emission limit.

**40 CFR Part 60 (NSPS)**

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

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

This rule applies to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a max design heat input capacity between 100 and 10 MMBtu/hr. The proposed fuel heaters would be considered process heaters which are not considered steam generating units according to the definitions in §60.41c. Therefore, the fuel heaters are not subject to this rule.

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

The CT units would be subject to 40 CFR Part 60, Subpart KKKK. The new CT units would be subject to the applicable emission limits, monitoring, recordkeeping, and reporting requirements of this subpart. Emission limits proposed as a part of BACT would be at least as stringent as the emission limits contained in this subpart.


The new CTs would be subject to this subpart to include the CO₂ emissions limitation. Stationary turbines that burn natural gas are not subject to any monitoring or reporting requirements under this subpart [40 CFR §60.5520(d)(1)]. Emission limits proposed as a part of BACT would be at least as stringent as the emission limits contained in this subpart. A CT generation limit (766,000 MWh (gross)/year) will be included in the permit to invoke the heat input standard (120 lbs CO₂e/MMBtu) applicability for the CT units under this rule.

**40 CFR Part 63 (NESHAP/MACT)**

**40 CFR Part 63, Subpart A**

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

This subpart is applicable to the proposed CT units. EPA issued a stay on the effectiveness of this rule’s requirements pertaining to lean premix gas-fired combustion turbines and new diffusion flame gas-fired turbines on August 18, 2004. The proposed CT units would be considered lean premix gas-fired combustion turbines. As a result, the CT units would be covered by the August 18, 2004 stay. As long as the stay is in place, these units would only be subject to the initial notification requirements in 40 CFR 63.6145. If the stay is lifted, the units would become subject to a formaldehyde emission limit of 91 ppbvd @ 15% O₂.


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


This subpart applies to coil-fired and oil-fired EGUs as defined in §63.10042. The proposed CTs would be natural gas-fired and do not meet that definition. As a result, this rule does not apply to the proposed CTs.

ADEM Admin. Code r. 335-3

Opacity

ADEM Admin. Code r. 335-3-4-.01 states that no person shall discharge from any source of emission, particulate of an opacity greater than twenty percent (20%), as determined by a six (6) minute average. ADEM 335-4-.01(b) states that during one six (6) minute period in any sixty (60) minute period a person may discharge into the atmosphere from any source of emissions, particulate of an opacity not greater than that designated as forty percent (40%) opacity. The proposed units would all be subject to this rule and would be expected to meet the applicable opacity requirements.
Particulate Matter (PM)
The fuel heaters and CT units would be subject to a PM emission limit according to Table 4-1 of ADEM Admin. Code r. 335-3-4-.03. Emissions from the units would be expected to be well below the allowable emission rate since natural gas would be the only fuel source.

Sulfur Dioxide (SO\textsubscript{2})
ADEM Admin. Code r. 335-3-5-.01(1)(b) assigns the proposed fuel heaters and CT units an allowable sulfur dioxide emission rate of 4.0 lb/MMBtu since the units would be located in a Category II county. Emissions from the units would be expected to be below the allowable emission rate since natural gas would be the only fuel source. In addition, these units are subject to more stringent BACT standards for SO\textsubscript{2}.

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

<table>
<thead>
<tr>
<th>Permit Number</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>701-0010-X015</td>
<td>Three (3) Simple Cycle Combustion Turbines</td>
</tr>
<tr>
<td>701-0010-X016</td>
<td>Three (3) 10 MMBtu/hr Natural Gas-Fired Fuel Heaters</td>
</tr>
</tbody>
</table>

Tyler Phillips
Industrial Minerals Section
Energy Branch
Air Division

Date: July 13, 2021
ATTACHMENT NO. 1

Air Quality Analysis
June 16, 2021

MEMORANDUM

TO: Tyler Phillips
Industrial Minerals Section
Energy Branch
Air Division

FROM: Jim Owen
Meteorological Section
Planning Branch
Air Division

SUBJECT: Air Dispersion Modeling of proposed new sources at the TVA facility in Colbert County, Alabama.

ADEM has completed its review of an air quality modeling analysis performed by the Tennessee Valley Authority (TVA) on behalf of TVA Colbert. TVA Colbert proposes to construct and operate three new natural gas fired combustion turbine (CT) generators and three new natural gas fuel heaters at their existing combustion turbine plant in Tuscumbia, Alabama. The purpose of this analysis was to assess the impacts on air quality from emissions of carbon monoxide (CO), nitrogen dioxide (NO₂), particulate matter with an aerodynamic diameter less than 2.5 microns (PM₂.₅), and particulate matter with an aerodynamic diameter less than 10 microns (PM₁₀) from the proposed new sources. An air quality analysis was performed for CO, NO₂, PM₂.₅, and PM₁₀, 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 NO₂ Tier 2 Ambient Ratio Method (ARM) as a default option when modeling NO₂.
METEOROLOGICAL DATA:

Surface and upper air meteorological data for the years 2014-2018 was used in all modeling. The surface data was from the Muscle Shoals, AL National Weather Service Office (NWS) and the upper air data was from the Nashville, TN NWS.

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$_2$. However, secondary PM$_{2.5}$ and Ozone impacts from NOx emissions alone were considered since SO$_2$ and VOC emissions are below their respective SER (Significant Emission Rate). This was based on the February 2020 EPA draft guidance on how to implement the modeling requirements to show PSD compliance for PM$_{2.5}$ and Ozone. For secondary PM$_{2.5}$ and Ozone, the total NOx emission rate of 380 TPY was used. The results for the MERPs analyses are presented in Table 1.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Secondary PM$_{2.5}$ (Daily)</td>
<td>96%</td>
</tr>
<tr>
<td>Secondary PM$_{2.5}$ (Annual)</td>
<td>56%</td>
</tr>
<tr>
<td>Ozone</td>
<td>244%</td>
</tr>
</tbody>
</table>

These results show that the MERPs values for secondary PM$_{2.5}$ are below 100%. However, secondary PM$_{2.5}$ impacts were added to primary PM$_{2.5}$ impacts for Class I and II screening modeling and compared to the SILs (see TABLE 3 and TABLE 5). Also, the results show that the MERPs for ozone are above 100%. Since the calculated consumption is over 100%, a cumulative analysis was required. A review of regional monitors in the northern Alabama region was necessary to determine if the 244%, or 2.44 ppb (based on the proposed ozone SIL of 1 ppb), were to be added to the ozone background that the sum would be less than the ozone NAAQS of 70 ppb. Based on the Muscle Shoals monitor located in Colbert county the addition of 2.44 ppb of ozone from the MERPs analysis added to the Muscle Shoals monitor’s 8 hour design value of 57 ppb (based on 2017-2019 data) gives a total of 59.44 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, NO₂, PM₂.₅, and PM₁₀ at TVA Colbert. Appendix A of this memo lists the stack parameters and emission rates for the proposed new sources at TVA Colbert that were used in the modeling.

A Cartesian receptor grid, centered on the TVA Colbert site and extending out to 10 kilometers (km) in all directions was used in the modeling. The receptor grid was generated using the following:
1. 50 meter (m) spacing along the fence line.
2. 100 m spacing from fence line out to 3 km.
3. 250 m spacing from 3 km to 5 km.
4. 500 m spacing from 5 km to 10 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, NO₂, and PM₁₀. Table 3 lists the results of screening modeling performed for PM₂.₅, including secondary concentrations.

### TABLE 2
CO, NO₂, and PM₁₀ Screening Modeling Results

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Max Conc. (µg/m³)</th>
<th>Signif. Level (µg/m³)</th>
<th>SIA (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>1 hour</td>
<td>28.20 (a)</td>
<td>2000</td>
<td>-</td>
</tr>
<tr>
<td>CO</td>
<td>8 hour</td>
<td>14.65 (a)</td>
<td>500</td>
<td>-</td>
</tr>
<tr>
<td>NO₂</td>
<td>1 hour</td>
<td>6.08 (b)</td>
<td>7.5</td>
<td>-</td>
</tr>
<tr>
<td>NO₂</td>
<td>Annual</td>
<td>0.14 (c)</td>
<td>1</td>
<td>-</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>24 hour</td>
<td>1.50 (a)</td>
<td>5</td>
<td>-</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>Annual</td>
<td>0.12 (c)</td>
<td>1</td>
<td>-</td>
</tr>
</tbody>
</table>

(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
PM₂.₅ Screening Modeling Results

<table>
<thead>
<tr>
<th>Averaging Period</th>
<th>Primary Concentration (µg/m³)</th>
<th>Secondary Concentration (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>Significance Level (µg/m³)</th>
<th>SIA (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>24 hour</td>
<td>1.10 (a)</td>
<td>0.06</td>
<td>1.16</td>
<td>1.2</td>
<td>-</td>
</tr>
<tr>
<td>Annual</td>
<td>0.11 (a)</td>
<td>0.003</td>
<td>0.113</td>
<td>0.3</td>
<td>-</td>
</tr>
</tbody>
</table>

(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 TVA Colbert is the Sipsey Wilderness Area (located 53 km from TVA Colbert). ADEM required a Class I Increment analysis due to the close proximity of TVA Colbert to Sipsey. Also, an Air Quality Related Values (AQRV) analysis was performed due to the fact that their Q/d value was greater than 10.

Class I Increment modeling was performed using AERMOD and AQRV modeling was performed using CALPUFF. The modeling performed addressed the Class I Increment, nitrogen deposition, and regional haze. The results of the Class I Increment analysis for NO_2 and PM_{10} are shown in Table 4 while the results for PM_{2.5} are shown in Table 5.

**TABLE 4**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Max. Predicted Concentration (µg/m³)</th>
<th>Significance Level (µg/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO_2</td>
<td>Annual</td>
<td>0.024</td>
<td>0.1</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>24 hour</td>
<td>0.090</td>
<td>0.3</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>Annual</td>
<td>0.007</td>
<td>0.2</td>
</tr>
</tbody>
</table>

**TABLE 5**

<table>
<thead>
<tr>
<th>Averaging Period</th>
<th>Primary Concentration (µg/m³)</th>
<th>Secondary Concentration (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>Significance Level (µg/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>24 hour</td>
<td>0.065</td>
<td>0.06</td>
<td>0.125</td>
<td>0.27</td>
</tr>
<tr>
<td>Annual</td>
<td>0.006</td>
<td>0.003</td>
<td>0.009</td>
<td>0.05</td>
</tr>
</tbody>
</table>

Results of the modeling indicated that the maximum predicted NO_2, PM_{10}, and PM_{2.5} concentrations for all averaging periods were below their respective Class I significance levels. Therefore, no further modeling was required.

A deposition analysis was performed for nitrogen. In this analysis, TVA Colbert’s contribution to the deposition of chemical species in the Class I area were evaluated against values recommended by the Federal Land Manager (FLM). The maximum predicted nitrogen deposition value is shown in Table 6.
### TABLE 6
Nitrogen Deposition

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Maximum Predicted Impact (Kg/Ha/Yr)</th>
<th>Screening Value (Kg/Ha/Yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen (as Nitrate)</td>
<td>0.0037</td>
<td>0.01</td>
</tr>
</tbody>
</table>

The result of the deposition analysis shows that the maximum predicted nitrogen deposition impact is below the threshold screening value recommended by the FLM. Therefore, no further analysis was required.

TVA Colbert’s contribution to regional haze was also addressed, per the FLAG report. Results of the regional haze analysis showed that the highest visibility change from the project was predicted to be 2.87%. Therefore, the threshold of 5% was never exceeded. As a result, no further analysis was required.

**CONCLUSION:**

In conclusion, emissions of CO, NO₂, PM₂.₅, and PM₁₀ from the proposed new sources at the TVA Colbert facility in Tuscumbia, Alabama, are not expected to cause or contribute to a violation of a NAAQS or Class I and II Increment. Also, predicted impacts on regional haze, as well as nitrogen deposition, at the Sipsey Wilderness Area are below the levels recommended by the FLM.
APPENDIX A

Stack Parameters and Emission Rates
For
Proposed New TVA Colbert Sources
### CCT CT and GH Stack Parameters

<table>
<thead>
<tr>
<th>Proposed Unit</th>
<th>Operating ID</th>
<th>UTM Zone 16, NAD83 (m)</th>
<th>UTM Zone 16, NAD83 (m)</th>
<th>Base Elev. (m)</th>
<th>Stack Height (m)</th>
<th>Stack Inside Dia. (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCT09</td>
<td>CCT11</td>
<td>422653.17</td>
<td>3844684.29</td>
<td>139.9</td>
<td>39.9</td>
<td>6.71</td>
</tr>
<tr>
<td>CCT10</td>
<td>CCT10</td>
<td>422628.42</td>
<td>3844645.86</td>
<td>139.9</td>
<td>39.9</td>
<td>6.71</td>
</tr>
<tr>
<td>CCT11</td>
<td>CCT09</td>
<td>422603.68</td>
<td>3844607.43</td>
<td>139.9</td>
<td>39.9</td>
<td>6.71</td>
</tr>
<tr>
<td>GH01</td>
<td>GH03</td>
<td>422540.63</td>
<td>3844601.42</td>
<td>139.9</td>
<td>9.14</td>
<td>0.61</td>
</tr>
<tr>
<td>GH02</td>
<td>GH02</td>
<td>422537.33</td>
<td>3844596.30</td>
<td>139.9</td>
<td>9.14</td>
<td>0.61</td>
</tr>
<tr>
<td>GH03</td>
<td>GH01</td>
<td>422534.03</td>
<td>3844591.17</td>
<td>139.9</td>
<td>9.14</td>
<td>0.61</td>
</tr>
</tbody>
</table>

1. Operating ID: "Proposed Unit" identifier was selected and utilized for all modeling. Once modeling was finalized, TVA Major Projects decided to re-identify the sources.

### Short-Term AERMOD Inputs for PM$_{10}$, PM$_{2.5}$, NO$_x$ (as NO$_2$), and CO

<table>
<thead>
<tr>
<th>ID</th>
<th>Stack-Exit Parameters</th>
<th>PM$_{10}$ (g/s)</th>
<th>PM$_{2.5}$ (g/s)</th>
<th>NO$_x$ (g/s)</th>
<th>CO (g/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Temp. (K)</td>
<td>Velocity (m/s)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CCT09</td>
<td>887</td>
<td>39.3</td>
<td>2.27E+00</td>
<td>2.27E+00</td>
<td>9.36E+00</td>
</tr>
<tr>
<td>CCT10</td>
<td>887</td>
<td>39.3</td>
<td>2.27E+00</td>
<td>2.27E+00</td>
<td>9.36E+00</td>
</tr>
<tr>
<td>CCT11</td>
<td>887</td>
<td>39.3</td>
<td>2.27E+00</td>
<td>2.27E+00</td>
<td>9.36E+00</td>
</tr>
<tr>
<td>GH01</td>
<td>688</td>
<td>9.42</td>
<td>1.71E-02</td>
<td>1.71E-02</td>
<td>1.38E-02</td>
</tr>
<tr>
<td>GH02</td>
<td>688</td>
<td>9.42</td>
<td>1.71E-02</td>
<td>1.71E-02</td>
<td>1.38E-02</td>
</tr>
<tr>
<td>GH03</td>
<td>688</td>
<td>9.42</td>
<td>1.71E-02</td>
<td>1.71E-02</td>
<td>1.38E-02</td>
</tr>
</tbody>
</table>

### Annual AERMOD Inputs for PM$_{10}$, PM$_{2.5}$, and NO$_x$ (as NO$_2$)

<table>
<thead>
<tr>
<th>ID</th>
<th>Stack-Exit Parameters</th>
<th>PM$_{10}$ (g/s)</th>
<th>PM$_{2.5}$ (g/s)</th>
<th>NO$_x$ (g/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Temp. (K)</td>
<td>Velocity (m/s)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CCT09</td>
<td>905</td>
<td>39.7</td>
<td>2.27E+00</td>
<td>9.29E+00</td>
</tr>
<tr>
<td>CCT10</td>
<td>905</td>
<td>39.7</td>
<td>2.27E+00</td>
<td>9.29E+00</td>
</tr>
<tr>
<td>CCT11</td>
<td>905</td>
<td>39.7</td>
<td>2.27E+00</td>
<td>9.29E+00</td>
</tr>
<tr>
<td>GH01</td>
<td>688</td>
<td>9.42</td>
<td>1.71E-02</td>
<td>1.38E-02</td>
</tr>
<tr>
<td>GH02</td>
<td>688</td>
<td>9.42</td>
<td>1.71E-02</td>
<td>1.38E-02</td>
</tr>
<tr>
<td>GH03</td>
<td>688</td>
<td>9.42</td>
<td>1.71E-02</td>
<td>1.38E-02</td>
</tr>
</tbody>
</table>
ATTACHMENT NO. 2

Proposed Permit Provisos
AIR PERMIT

PERMITTEE: TENNESSEE VALLEY AUTHORITY

FACILITY NAME: COLBERT COMBUSTION TURBINE PLANT

LOCATION: TUSCUMBIA, COLBERT COUNTY, ALABAMA

<table>
<thead>
<tr>
<th>PERMIT NUMBER</th>
<th>DESCRIPTION OF EQUIPMENT, ARTICLE, OR DEVICE</th>
</tr>
</thead>
<tbody>
<tr>
<td>701-0010-X015</td>
<td>Three (3) Simple Cycle Combustion Turbines</td>
</tr>
<tr>
<td></td>
<td>(rated at 229 MW and 2,254 MMBtu/hr, each)</td>
</tr>
</tbody>
</table>

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
General Permit Provisos

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(c) A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.
(d) A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

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

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

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

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

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

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

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

(c) by paving;

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

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

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

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

21. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.
22. The permittee shall keep this permit under file or on display at all times at the site where the facility for which the permit is issued is located and shall make the permit readily available for inspection by any or all persons who may request to see it.

23. An annual compliance certification shall be submitted by November 2, covering the reporting period of September 3 through September 2 of the previous calendar year, unless more frequent periods are specified according to the specific rule governing the source or required by the Department.

   (a) The compliance certification shall include the following:

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

   b. The compliance status;

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

   d. Whether compliance has been continuous or intermittent; and

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

   (b) The compliance certification shall be submitted to:

       Alabama Department of Environmental Management
       Air Division
       P.O. Box 301463
       Montgomery, AL 36130-1463
### Three (3) Simple Cycle Combustion Turbines

#### Provisos

<table>
<thead>
<tr>
<th>Applicability</th>
<th>Regulations</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. These units are part of a source subject to the applicable requirements of ADEM Admin. Code r. 335-3-16, “Major Source Operating Permits”.</td>
<td>Rule 335-3-16-.03</td>
</tr>
<tr>
<td>2. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01, “Control of Particulate Emissions – Visible Emissions”.</td>
<td>Rule 335-3-4-.01</td>
</tr>
<tr>
<td>3. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.03, “Control of Particulate Emissions – Fuel Burning Equipment”.</td>
<td>Rule 335-3-4-.03</td>
</tr>
<tr>
<td>4. These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-5-.01, “Control of Sulfur Compound Emissions – Fuel Combustion”.</td>
<td>Rule 335-3-5-.01</td>
</tr>
<tr>
<td>5. These units have limits in accordance with the applicable requirements of ADEM Admin. Code r. 335-3-14-.04, “Air Permits Authorizing Construction in Clean Air Areas [Prevention of Significant Deterioration]”.</td>
<td>Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>6. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart KKKK, “Standards of Performance for Stationary Combustion Turbines”.</td>
<td>Rule 335-3-10-.02(89) 40 CFR §60.4305(a)</td>
</tr>
<tr>
<td>7. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart TTTT, “Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units”.</td>
<td>Rule 335-3-10-.02(96) 40 CFR §60.5509(a)(1)</td>
</tr>
<tr>
<td>8. These units are subject to the applicable requirements of 40 CFR Part 63, Subpart YYYYY, “National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines”.</td>
<td>Rule 335-3-11-.06(103) 40 CFR §63.6085</td>
</tr>
<tr>
<td>9. These units are subject to the applicable requirements of 40 CFR Part 60, Subpart A, “General Provisions”.</td>
<td>Rule 335-3-10-.02(1) 40 CFR §60.1(a) 40 CFR §60.5570</td>
</tr>
<tr>
<td>10. These units are subject to the Acid Rain Rules contained in ADEM Admin. Code r. 335-3-18 and 40 CFR Parts 72, 73, and 75.</td>
<td>Rule 335-3-18 40 CFR Parts 72, 73, 75</td>
</tr>
</tbody>
</table>
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. These units are subject to the applicable provisions of the Cross-State Air Pollution Rule found in ADEM Admin. Code r. 335-3-5-.06 through 335-3-5-.36 and ADEM Admin. Code r. 335-3-8-.07 through 335-3-8-.70. Rules 335-3-5-.06 through 335-3-5-.36 and Rules 335-3-8-.07 through 335-3-8-.70


### Emission Standards

1. The sulfur dioxide (SO$_2$) emission rate from each unit shall not exceed 4.0 lb/MMBtu. Rule 335-3-5-.01(1)(b)

2. Particulate matter (PM) emissions from each unit shall not exceed 0.12 lb/MMBtu per Table 4-1 of ADEM Admin. Code r. 335-3-4-.03. Rule 335-3-4-.03(1)

3. Visible emissions from each unit shall not exceed 20% opacity except during one six (6) minute period in any sixty (60) minute period which opacity shall not exceed 40%. Rule 335-3-4-.01(1)

4. The nitrogen oxides (NO$_X$) emission rate from each unit shall not exceed 15 ppm (at 15% O$_2$) or 0.43 lb/MWh of useful output. Compliance is based on a 4-hour rolling average as determined by CEMS. Rule 335-3-10-.02(89) 40 CFR §60.4320(a) Subpart KKKK, Table 1 40 CFR §60.4350(g)

5. The permittee must not burn any fuel in the turbines which contains total potential sulfur emissions in excess of 26 ng SO$_2$/J (0.060 lb/MMBtu) heat input. Rule 335-3-10-.02(89) 40 CFR §60.4330(a)(2)

6. Each unit shall supply their design efficiency multiplied by their potential electric output or less as net-electric sales. Rule 335-3-10-.02(96) 40 CFR §60.5520(a) Subpart TTTT, Table 2

   Each of these units shall not exceed 766,000 MWh (gross)/year, based on a 12-operating month rolling total.

7. The carbon dioxide (CO$_2$) emission rate from each simple-cycle unit shall not exceed 120 lbs CO$_2$/MMBtu. Rule 335-3-10-.02(96) 40 CFR §60.5520(a) Subpart TTTT, Table 2 Rule 335-3-14-.04 (BACT)
<table>
<thead>
<tr>
<th></th>
<th>Regulations</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.</td>
<td>The NO\textsubscript{X} emission rate from all combustion turbine units (identified in Air Permit No. 701-0010-X015) and gas heaters (identified on Air Permit No. 701-0010-X016) shall not exceed 380 tons based on a 12-month rolling total. This includes emissions during periods of startup and shutdown. Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>9.</td>
<td>Carbon monoxide (CO) emissions shall not exceed 500 lbs per combustion turbine (CT) startup/shutdown event. Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>10.</td>
<td>The combustion turbines shall fire only natural gas. Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>11.</td>
<td>Particulate matter less than 10 microns (PM\textsubscript{10}) and particulate matter less than 2.5 microns (PM\textsubscript{2.5}) emissions from each unit shall not exceed 18 lb/hr and 0.008 lb/MMBtu. Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>12.</td>
<td>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)</td>
</tr>
<tr>
<td>13.</td>
<td>The CTs are subject to numeric emission limitations and work practice standards (WPS) as specified in Provisos 14 through 16 below.</td>
</tr>
<tr>
<td>14.</td>
<td>Except as provided for in Proviso 16 below, the NO\textsubscript{X} emission rate from each unit shall not exceed 9 ppmvd @ 15% O\textsubscript{2}. Compliance is based on a 3-hour rolling average as determined by CEMS. Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>15.</td>
<td>Except as provided for in Proviso 16 below, the CO emission rate from each unit shall not exceed 9 ppmvd @ 15% O\textsubscript{2} based on a 3-hr rolling average as determined by CEMS. Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>16.</td>
<td>During periods of startup and shutdown (as defined in Proviso 17 below), the permittee shall comply with the following work practice standards in lieu of the numeric limitations in Provisos 14-15 above: a) The permittee shall take all reasonable actions to minimize the magnitude and duration of emissions during the periods listed above. b) Employ good operation and maintenance practices on the Turbines. c) Comply with emissions monitoring, recordkeeping, and reporting requirements in this permit. Rule 335-3-14-.03(1)(h)</td>
</tr>
<tr>
<td>17.</td>
<td>Startup and shutdown are defined below: Rule 335-3-14-.04</td>
</tr>
</tbody>
</table>
(a) Startup – The period beginning at initial fuel ignition and ending when 115 MW is first achieved.

(b) Shutdown – The period beginning with the combustion turbine leaving Mode 6.3P operation, for the purpose of shutting down the unit, and ending with its flame being extinguished.

Compliance and Performance Test Methods and Procedures

1. Compliance with the NO\textsubscript{x} emission limitation in Emission Standards Proviso 4 and 14 shall be determined using a NO\textsubscript{x} diluent CEMS that is installed, operated, maintained, and certified according to 40 CFR Part 75, Appendix A.

Rule 335-3-10-.02(89)
40 CFR §60.4340
Rule 335-3-14-.04
(BACT)

2. For purposes of demonstrating compliance with the sulfur content of the fuel standard in Proviso 5 of the Emission Standards Section, the owner or operator may use one of the following options:

(a) Analyze the sulfur content of the fuel using ASTM D1072, or alternatively D3246, D4048, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377;

(b) Maintain a current, valid fuel purchase contract, tariff sheet, or transportation contract for the natural gas specifying the maximum total sulfur content is less than 20 grains sulfur per 100 scf and has potential sulfur emissions of less than 26 ng SO\textsubscript{2}/J (0.060 lb SO\textsubscript{2}/MMBtu) heat input;

(c) Conduct daily sampling of the natural gas sulfur content for the first 30-unit operating days following the change and annually thereafter to show the actual fuel sulfur content is less than 10 grains sulfur per 100 scf; or

(d) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO\textsubscript{2}/J (0.060 lb SO\textsubscript{2}/MMBtu) heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

Rule 335-3-10-.02(89)
40 CFR §60.4360

3. Compliance with the CO\textsubscript{2} emissions limitation in Emission Standards Proviso 7 shall be determined using the methods provided in 40 CFR Part 60, Subpart TTTT.

Rule 335-3-10-.02(96)
40 CFR §60.5540

4. Compliance with the SO\textsubscript{2} emissions limitations in Emission Standards Proviso 1 shall be determined by EPA Reference Method 6 or 20 as found in 40 CFR Part 60, Appendix A.

Rule 335-3-1-.05(1)
### Regulations

<table>
<thead>
<tr>
<th>Rule</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.</td>
<td>Compliance with the opacity standard in Emission Standards Proviso 3 shall be determined by EPA Reference Method 9 of 40 CFR Part 60, Appendix A.</td>
</tr>
<tr>
<td>6.</td>
<td>Compliance with the CO emission limitation in Emission Standards Proviso 15 shall be determined using a CO diluent CEMS that is installed, operated, maintained, and certified according to 40 CFR Part 60, Appendix B.</td>
</tr>
<tr>
<td>7.</td>
<td>Compliance with the PM emission limitation in Emission Standards Proviso 11 shall be determined by either Method 5, 17, or 201 along with Method 202 of 40 CFR Part 60, Appendix A.</td>
</tr>
<tr>
<td>8.</td>
<td>Compliance with the PM emission limitation in Emission Standards Proviso 2 shall be determined by Method 5 or 17 of 40 CFR Part 60, Appendix A.</td>
</tr>
<tr>
<td>9.</td>
<td>Any performance tests required shall be conducted and data recorded 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.</td>
</tr>
<tr>
<td>10.</td>
<td>The permittee must operate and maintain the stationary combustion turbines, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.</td>
</tr>
</tbody>
</table>

### Emission Monitoring

1. A continuous emissions monitoring system (CEMS) to measure NO\textsubscript{x} emissions shall be installed and operated at a location approved by the Director. The CEMS shall meet the specification and procedures of 40 CFR Part 75 and will be certified and maintained in accordance with 40 CFR Part 75. | Rule 335-3-10-.02(89) 40 CFR §60.4345 Rule 335-3-14-.04 (BACT) |

2. A continuous emissions monitoring system (CEMS) to measure CO emissions shall be installed and operated at a location approved by the Director. The CEMS shall meet the specification and procedures of 40 CFR Part 60, Appendix B and will be certified and maintained in accordance with 40 CFR Part 60, Appendix B. Quality assurance checks are to be performed on each CO diluent CEMS consistent with | Rule 335-3-14-.04 (BACT) |
the provisions of 40 CFR Part 75, Appendix B in lieu of 40 CFR Part 60, Appendix B.

3. The Permittee shall maintain purchase records of natural gas.

Recordkeeping and Reporting Requirements

1. An excess emissions report for each combined turbine stack will be submitted to the ADEM within thirty days of the end of each calendar quarter. The report will contain the following format:

**NOx**

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

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

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

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

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

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

F = Startup/Shutdown

G. Net Excess Emissions = D – F

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

\[ = [1 - (G/(B - F))] x 100 \]

\[ = [(B - F - G)/(B - F)] x 100 \]

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

\[ = (D/B) x 100 \]

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

\[ = [(B - F)/ B ] x 100 \]

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

SU/SD = (F/B) x 100

**CO**

A. Source Operating Time (all times and periods in hours)
B. Time Monitoring System was Able to Record Source Performance *

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

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

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

F. Number of periods above the Proviso 14 limitation during periods subject to work practice standards and the startup limitation – F (3-hour periods)
   F = Startup/Shutdown

G. Net Excess Emissions = D – F

H. Net Source Performance (%) - H(x):
   = [1 - (G/(B - F))] x 100
   = [(B - F - G)/(B - F)] x 100

I. Overall Exceedances (%) - Percent of time above the Proviso 14 limitations due to all reasons:
   = (D/B) x 100

J. Net Exceedances (%) - Percent of time above the Proviso 14 limitation during periods subject to the numerical limitation:
   = [(B – F)/ B ] x 100

K. Percent of time above the numeric limitation during periods subject to work practice limitations and the startup limitations
   SU/SD = (F/B) x 100

L. Number of startup events

M. Number and magnitude of any startup limitation exceedances

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

** Report date, time duration, magnitude, cause and corrective action taken for each occurrence.

NOTE: Data recorded during periods of system breakdowns, repairs, adjustments, and calibration checks shall not be included in any of the above data averages.
2. The Permittee must keep records of natural gas sulfur content showing the sulfur content of gas fired in the CTs does not exceed 0.15 gr/100 scf. | Rule 335-3-14-.04

3. The Permittee must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. | Rule 335-3-10-.02(89)  
40 CFR §60.4375(a)

4. All reports required under §60.7(c) must be postmarked by the 30th day following the end of each calendar quarter. | Rule 335-3-10-.02(89)  
40 CFR §60.4395  
Rule 335-3-14-.04

5. The Permittee must keep a record of the 12-month rolling total NOX emissions (in tons) for the CTs and Gas Heaters. | Rule 335-3-14-.04

6. The Permittee must keep a record of the 12-month rolling total electric output (in MWh) for each these units. | Rule 335-3-14-.04

7. The Permittee must notify the Department prior to tuning events. The notification shall be submitted at least 24 hours prior to the event and include the following information:

   (a) Specific units to be tuned.
   (b) When tuning is expected to begin.
   (c) Expected duration of the tuning event.
   (d) Reason for the tuning event.

   The Permittee must notify the Department of the duration and magnitude of any exceedances noted during the tuning event within 48 hours or the next working day. | Rule 335-3-14-.04

8. The facility shall comply with the recordkeeping and reporting requirements of CSAPR found in Rules 335-3-5-.31, 335-3-5-.35, 335-3-8-.33, 335-3-8-.37, 335-3-8-.65, and 335-3-8-.69. | Rules 335-3-5-.31, 335-3-5-.35  
Rules 335-3-8-.33, 335-3-8-.37, 335-3-8-.65, 335-3-8-.69

AIR PERMIT

PERMITTEE: TENNESSEE VALLEY AUTHORITY
FACILITY NAME: COLBERT COMBUSTION TURBINE PLANT
LOCATION: TUSCUMBIA, COLBERT COUNTY, ALABAMA

<table>
<thead>
<tr>
<th>PERMIT NUMBER</th>
<th>DESCRIPTION OF EQUIPMENT, ARTICLE, OR DEVICE</th>
</tr>
</thead>
<tbody>
<tr>
<td>701-0010-X016</td>
<td>Three (3) 10 MMBtu/hr Natural Gas-Fired Gas Heaters</td>
</tr>
</tbody>
</table>

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
General Permit Provisos

24. 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.

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

26. 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.

27. 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.

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

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

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

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

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

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

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

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulates</td>
<td>(X)</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>(X)</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td>()</td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td>(X)</td>
</tr>
<tr>
<td>Volatile Organic Compounds</td>
<td>()</td>
</tr>
<tr>
<td>Visible Emissions</td>
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</tbody>
</table>

35. 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.

36. 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.

37. 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.

38. 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.

39. 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:

(e) 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.

(f) 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).

(g) 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.

(h) 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.

40. 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:

(e) 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;

(f) by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

(g) by paving;

(h) 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.

41. 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.

42. 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.

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

44. 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.

45. An annual compliance certification shall be submitted by November 2, covering the reporting period of September 3 through September 2 of the previous calendar year, unless more frequent periods are specified according to the specific rule governing the source or required by the Department.
(c) The compliance certification shall include the following:
   a. The identification of each term or condition of this permit that is the basis of the certification;
   b. The compliance status;
   c. The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);
   d. Whether compliance has been continuous or intermittent; and
   e. Such other facts as the Department may require in order to determine the compliance status of the source.

(d) The compliance certification shall be submitted to:

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

### Provisos

#### Applicability

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>These units are part of a source subject to the applicable requirements of ADEM Admin. Code r. 335-3-16, “Major Source Operating Permits”. Rule 335-3-16-.03</td>
</tr>
<tr>
<td>2.</td>
<td>These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01, “Control of Particulate Emissions – Visible Emissions”. Rule 335-3-4-.01</td>
</tr>
<tr>
<td>3.</td>
<td>These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.03, “Control of Particulate Emissions – Fuel Burning Equipment”. Rule 335-3-4-.03</td>
</tr>
<tr>
<td>4.</td>
<td>These units are subject to the applicable requirements of ADEM Admin. Code r. 335-3-5-.01, “Control of Sulfur Compound Emissions – Fuel Combustion”. Rule 335-3-5-.01</td>
</tr>
<tr>
<td>5.</td>
<td>These units have limits in accordance with the applicable requirements of ADEM Admin. Code r. 335-3-14-.04, “Air Permits Authorizing Construction in Clean Air Areas [Prevention of Significant Deterioration]”. Rule 335-3-14-.04 (BACT)</td>
</tr>
<tr>
<td>6.</td>
<td>These units are subject to the applicable requirements of 40 CFR Part 63, Subpart DDDDD, “National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Gas heaters and Process Heaters”. Rule 335-3-11-.06(107) 40 CFR §63.7485</td>
</tr>
<tr>
<td>7.</td>
<td>These units are subject to the applicable requirements of 40 CFR Part 63, Subpart A, “General Provisions”. Rule 335-3-11-.06(1) 40 CFR §63.1(a)(4)(i) 40 CFR §63.7565</td>
</tr>
<tr>
<td>8.</td>
<td>These units are subject to the applicable provisions of 40 CFR Part 98, “Mandatory Greenhouse Gas Reporting”. 40 CFR Part 98</td>
</tr>
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#### Emission Standards

<p>| | |</p>
<table>
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<tr>
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</thead>
<tbody>
<tr>
<td>1.</td>
<td>The permittee shall not discharge to the atmosphere particulate of an opacity greater than 20%, as determined by a six-minute average, except that during one six-minute period in any sixty (60) minute period, the permittee may discharge into the atmosphere particulate of an opacity not greater than 40%. Rule 335-3-4-.01(1)</td>
</tr>
</tbody>
</table>
2. The nitrogen oxide (NO\textsubscript{X}) emission rate from each gas heater shall not exceed 0.011 lb/MMBtu.  
   Rule 335-3-14-.04 (BACT)

3. The carbon monoxide (CO) emission rate from each gas heater shall not exceed 0.08 lb/MMBtu.  
   Rule 335-3-14-.04 (BACT)

4. Particulate matter less than 10 microns (PM\textsubscript{10}) and particulate matter less than 2.5 microns (PM\textsubscript{2.5}) emissions from each gas heater shall not exceed 0.008 lb/MMBtu (filterable).  
   Rule 335-3-14-.04 (BACT)

5. The carbon dioxide equivalent (CO\textsubscript{2}e) emission rate from each gas heater shall not exceed 117.1 lb/MMBtu.  
   Rule 335-3-14-.04 (BACT)

6. The NO\textsubscript{X} emission rate from all combustion turbine units (identified in Air Permit No. 701-0010-X015) and gas heaters (identified on Air Permit No. 701-0010-X016) shall not exceed 380 tons based on a 12-month rolling total. This includes emissions during periods of startup and shutdown.  
   Rule 335-3-14-.04 (BACT)

7. The SO\textsubscript{2} emission rate from each gas heater shall not exceed 4.0 lb/MMBtu.  
   Rule 335-3-5-.01(1)(b)

8. Particulate Matter (PM) emissions from each gas heater shall not exceed the allowable per Table 4-1 of ADEM Admin. Code r. 335-3-4-.03.  
   Rule 335-3-14-.04 (BACT)

9. The gas heaters shall only combust natural gas.  
   Rule 335-3-14-.04 (BACT)

10. The gas heaters shall utilize good combustion practices.  
    Rule 335-3-14-.04 (BACT)

11. The permittee shall conduct an annual tune-up of the gas heaters unless the unit employ’s a continuous oxygen trim system to maintain an optimum air to fuel ratio, in which case the tune up must be performed once every five years. The tune-up shall be conducted as specified in 40 CFR §63.7540.  
    Rule 335-3-11-.06(107)  
    40 CFR §63.7500(a)(1)

**Compliance and Performance Test Methods and Procedures**

1. Compliance with the particulate matter emission standards shall be determined by EPA Reference Method 5 or 17, as found in 40 CFR Part 60, Appendix A.  
   Rule 335-3-1-.05

2. Compliance with the opacity standard shall be determined by EPA Reference Method 9, as found in 40 CFR Part 60, Appendix A.  
   Rule 335-3-1-.05
3. Compliance with the NO\textsubscript{X} emission standard shall be determined by EPA Reference Method 7 or 7E, as found in 40 CFR Part 60, Appendix A. **Rule 335-3-1-.05**

4. Compliance with the CO emission standard shall be determined by EPA Reference Method 10, as found in 40 CFR Part 60, Appendix A. **Rule 335-3-1-.05**

5. Compliance with the SO\textsubscript{2} emission standards shall be determined by EPA Reference Method 6, as found in 40 CFR Part 60, Appendix A. **Rule 335-3-1-.05**

**Emission Monitoring**

1. There are no specific emission monitoring requirements for these units.

**Recordkeeping and Reporting Requirements**

1. The permittee shall comply with the applicable recordkeeping and reporting requirements of 40 CFR Part 63, Subpart DDDDD for the gas heaters. **Rule 335-3-11-.06(107)**

2. The Permittee must keep a record of the 12-month rolling total NO\textsubscript{X} emissions (in tons) for the CTs and Gas Heaters. **Rule 335-3-14-.04**

3. The permittee shall comply with the recordkeeping and reporting requirements of the Mandatory Greenhouse Gas Reporting Rule in 40 CFR Part 98 for the gas heaters. **40 CFR Part 98**