October 22, 2020

Via Email to: airmail@adem.alabama.gov

Ronald W. Gore, Chief
Air Division, Alabama Department of Environmental Management
P.O. Box 301463
Montgomery, Alabama 36130-1463

Re: Comments on the Draft Air Construction PSD Permit for Alabama Power Company Barry Steam Plant Units 8 and 9 | Facility No. 503-1001

Dear Mr. Gore:

The Southern Environmental Law Center,1 on behalf of Energy Alabama,2 Gasp,3 Mobile Baykeeper,4 and Sierra Club5 (together, “Commenters”), respectfully submits the attached comments on the draft Prevention of Significant Deterioration (PSD) Permit, Permit Numbers 503-1001-X014, 503-1001-X015, and 503-1001-X016, (referred to as the “Draft Permit”) for Alabama Power Company (“Alabama Power” or “Company”) to construct and operate two gas units (“Barry Units 8 and 9” or the “units”) at Alabama Power’s Barry Steam Plant (“Barry” or “Plant”). The Permit was noticed for public comment by the Alabama Department of Environmental Management (ADEM) on August 19, 2020. Due to requests for a public hearing, ADEM held a public hearing on three permits, including the above-mentioned Draft Permit, on October 15, 2020 in Saraland, Alabama, and extended the public comment period until October 22, 2020. We appreciate the opportunity to comment on the Draft Permit.

1 The Southern Environmental Law Center is a non-profit, regional environmental organization dedicated to protecting natural resources, preserving special places, and promoting vibrant communities throughout the Southeast. See http://www.southernenvironment.org.
2 Energy Alabama is an Alabama nonprofit association seeking to accelerate the state’s transition to sustainable energy. Energy Alabama works with governmental entities, utilities and the general public to grow the awareness and use of sustainable energy. See https://alcse.org.
3 Gasp is an Alabama nonprofit association seeking to improve the environmental, economic and public health of Alabama. It has been actively involved in addressing community concerns involving air quality issues in Birmingham and in communities throughout the state. See https://gaspgroup.org/.
4 Mobile Baykeeper is a twenty-three-year-old environmental nonprofit organization with a mission of providing citizens a means to protect the beauty, health and heritage of the Mobile Bay Watershed and our coastal communities. Mobile Baykeeper submits these comments on behalf of its board, officers, staff and more than 4,500 members. See https://www.mobilebaykeeper.org/.
5 Sierra Club is the nation’s largest and oldest environmental nonprofit organization. It aims to improve environmental quality for its many members who live, recreate, work and purchase electricity in Alabama. To this end, Sierra Club is actively participating in state regulatory reviews of Alabama Power’s existing and planned polluting activities at Barry. See https://www.sierraclub.org/.
INTRODUCTION

The Plant, located roughly 25 miles north of Mobile, Alabama in the Mobile Tensaw River Delta, has been in operation since 1952. The Plant currently operates two tangentially-fired units that burn natural gas (Barry Units 1 and 2), two tangentially-fired units that burn coal with natural gas start-up fuel (Barry Units 4 and 5), and two natural gas-fired combined cycle units (Barry Units 6 and 7). Barry Units 1 and 2 have a normal full load of approximately 85 megawatts (MW), Barry Unit 4 has a normal full load of approximately 376 MW, Barry Unit 5 has a normal full load of approximately 785 MW, and Barry Units 6 and 7 each generate approximately 500 MW.6

Alabama Power now proposes to construct and operate up to two new natural gas-fired combined cycle electric generating units, referred to as Barry Units 8 and 9, each with a generating capacity of approximately 743 MW (after completion of proposed future upgrades). Barry Units 8 and 9 will each include a Mitsubishi Hitachi Power Systems M501JAC class natural gas-fired combustion turbine, a supplementary-fired Heat Recovery Steam Generator, and a steam turbine generator.7 They will also include “typical ancillary equipment for a combined cycle power plant such as an auxiliary boiler, emergency generators, fire water pump engine, and mechanical draft cooling towers.”8 Barry Units 8 and 9 along with the ancillary equipment will be referred to throughout these comments as the “Project.”

The Project will have the potential to emit significant amounts of nitrogen oxide (NOx) (350.2 tons per year (tpy)), carbon monoxide (CO) (520.7 tpy), volatile organic compounds (VOC) (383.4 tpy), sulfur dioxide (SO2) (70.9 tpy), particulate matter with a diameter of 10 microns or less (PM10) (189.7 tpy), particulate matter with a diameter of 2.5 microns or less (PM2.5) (183.7 tpy), and greenhouse gases (GHG) (4,937,975 tpy).9 To control some of the pollution, the Barry Units 8 and 9 will be equipped with selective catalytic reduction (SCR) to limit NOx emissions and an oxidation catalyst system to minimize carbon monoxide and VOC emissions.10

Plant Barry is located along the Mobile River within the Mobile Tensaw River Delta, an area rich in biodiversity and commonly referred to as “America’s Amazon.” It is the largest river delta and wetland in Alabama, and the second largest river delta in the nation.11 At approximately 45 miles long and 8 miles wide, the Delta “is characterized by a large number of tributary rivers, streams, bayous, and creeks which form a maze of waterways, including the waters of the Tensaw, Mobile, Tombigbee and Alabama rivers.”12 It is one of Alabama’s most

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7 Ala. Power Co., Air Construction Permit Application, Plant Barry Units 8 and 9 Combined Cycle Project, Mobile County, Alabama, at 1-1 (Feb. 2020) [hereinafter Permit Application].
8 Id. at 3-5 (Table 3-5)
9 Id. at 1-1.
11 Id.
intact preserved areas, which is important because filters up to 15% of the nation’s fresh water.\textsuperscript{13} The Delta also serves as home to over 60 rare, imperiled, threatened or endangered species, including the black bear, the American alligator and the Alabama red-bellied turtle.\textsuperscript{14} The proposed new Units would be directly adjacent to Ellicott’s Stone Historical Park. Ellicott’s Stone was set on April 10, 1799 and is “one of the most important early boundary markers in the history of the Americas, demarking the boundary between Spanish and U.S. territory.”\textsuperscript{15}

The purposes of the PSD provisions of the Clean Air Act (CAA), CAA §§ 160-169, 42 U.S.C. §§ 7470-7492 include:

\begin{quote}
[P]rotect[ing] public health and welfare from any actual or potential adverse effect which in the [Environmental Protection Agency] Administrator’s judgment may reasonably be anticipated to occur from air pollution . . . notwithstanding attainment or maintenance of all national ambient air quality standards;\textsuperscript{16}
\end{quote}

and

\begin{quote}
[A]ssur[ing] that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.\textsuperscript{17}
\end{quote}

As will be discussed in further detail below, the primary mechanism through which PSD review ensures these goals are met is by mandating the use of “best achievable control technology” (BACT) to control emissions of pollutants regulated under the Clean Air Act and by limiting the increased air pollutant concentrations to within “maximum allowable increases” so as not to significantly degrade air quality. In no event can pollution from a proposed project cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS). The Draft Permit at issue does not adequately evaluate and prescribe BACT for Alabama Power to control emissions of pollutants regulated by the Clean Air Act, nor does it rigorously evaluate the proposed Project’s impacts on air pollutant concentrations to adequately find that the Project will not cause or contribute to a violation of any ambient air standard.

The Draft Permit contains multiple deficiencies, many of which are traceable to (1) the improper aggregation of separate projects into one single PSD permit; (2) the defective process by which BACT was chosen; and (3) the incomplete and unreliable data submitted by Alabama Power to demonstrate compliance with ambient air quality standards. As a result, the Draft Permit allows blatant violations of the Clean Air Act, to the detriment of the health and well-

\begin{flushleft}
\textsuperscript{13} Id.
\textsuperscript{16} CAA § 160(1), 42 U.S.C. §7407(1).
\textsuperscript{17} Id. § 160(5).
\end{flushleft}
being of the people of south Alabama and the State as a whole, and the rich, biodiverse environment surrounding Plant Barry. Thus, as currently written, the proposed permit should be denied.

**BACKGROUND ON THE PSD PERMITTING PROCESS**

Alabama’s plan to implement the federal Clean Air Act (state implementation plan, or SIP) obligates ADEM to impose “enforceable emissions limitations and other control measures, means, or techniques . . . as may be necessary to appropriate to meet the applicable [CAA] requirements.” For areas, including those surrounding the Plant Barry site, that have not been designated as having levels of ambient air pollution that fall short of the national ambient air quality standards, Alabama is required to implement the PSD program that is meant “to prevent significant deterioration of air quality in each region . . . designated pursuant to [CAA § 107] as attainment or unclassifiable.” While Alabama has, through its SIP, accepted authority for implementing the PSD program, the federal Environmental Protection Agency (EPA) retains authority to ensure the CAA is being faithfully implemented.

To carry out the PSD program, Alabama permitting authorities must vet every new “major emitting facility” in the state through a permitting process “designed to ensure that the air quality in attainment areas or areas that are already ‘clean’ will not degrade.”

Generally speaking, the program requires Alabama permitting authorities to ensure that a new facility fulfills the following requirements before it permits construction:

- **Meets BACT.** The facility is “subject to the best available control technology [(BACT)] for each criteria pollutant subject to regulation under [the CAA] emitted from, or which results from, such facility.”

- **Complies with maximum allowable increases.** The facility must demonstrate that it will not cause or contribute to emissions above the maximum allowable increases or maximum allowable concentration of pollutants more than one time per year.

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18 CAA § 110(a)(2)(A), 42 U.S.C. § 7410(a)(2)(A); see Prevention of Significant Deterioration of Air Quality; Full Delegation of Authority to the State of Alabama, 45 Fed. Reg. 80,583 (Dec. 5, 1980) (“We have reviewed the procedures for new source review of the State of Alabama and have determined that they provide an adequate and effective procedure for the implementation of all portions of the PSD program by the State of Alabama . . . [W]e hereby delegate our authority for all portions of the Federal PSD program . . . ”).

19 The fact that an area has not been designated as nonattainment does not necessarily imply that its air meets the NAAQS—only that no measurements have been reported to the EPA indicating that the air quality falls short of the NAAQS. See generally CAA § 107(d), 42 U.S.C. § 7407(d) (laying out process in which Governor of each state “shall . . . submit to the Administrator a list of all areas . . . in the State, designating as nonattainment, any area that does not meet . . . the national primary or secondary ambient air quality standard for the pollutant.”). Commenters do not concede that Plant Barry and/or Mobile County are in “attainment.”


21 See CAA § 167, 42 U.S.C. § 7477 (instructing EPA to “take such measures, including issuance of an order, or seeking injunctive relief, as necessary to prevent the construction” of a major pollutant emitting facility that does not meet the PSD requirements).

22 CAA § 165(a), 42 U.S.C. § 7475(a).


24 CAA § 165(a)(4).

25 Id. § 165(a)(3)(A).
• **Does not contribute to nonattainment.** The facility must demonstrate that it will not cause or contribute to violation of any national ambient air quality standard in any air quality control region.\\(^{26}\)

• **Complies with other standards.** The facility must demonstrate that it will not cause or contribute the violation of any other applicable emission standard or standard of performance in the CAA.\\(^{27}\)

• **Conducts air quality analysis.** The owner or operator must conduct “an analysis of any air quality impacts projected for the area as a result of growth associated with such facility.”\\(^{28}\)

• **Conducts necessary monitoring.** The facility must agree to “conduct such monitoring as may be necessary to determine the effect which emissions from any such facility may have . . . on air quality . . . .”\\(^{29}\)

**COMMENTS ON THE PRELIMINARY DETERMINATION AND DRAFT PSD PERMIT FOR BARRY UNITS 8 AND 9**

I. **Flawed Aggregation of Multiple Projects in a Single PSD Permit**

Alabama’s PSD regulations “apply to the construction of any new major stationary source . . . or any project at an existing major stationary source in an area designated as attainment or unclassified under sections 107(d)(1)(A)(ii) or (iii) of the Clean Air Act.”\\(^{30}\) A project is “a physical change in, or change in the method of operation of, an existing major stationary source.”\\(^{31}\) A physical change or change in the method of operation includes “fabrication, erection, installation, demolition, or modification of an emissions unit.”\\(^{32}\) Additionally, the regulations define “major modification” to mean “any physical change in or change in the method of operation of a major stationary source that would result in a significant . . . net emissions increase . . . of any regulated NSR pollutant.”\\(^{33}\)

When an applicant seeks a permit for multiple projects under the PSD program, as Alabama Power does here, the permit writer must determine whether the projects are legally eligible to be aggregated under a single PSD permit. EPA’s project aggregation policy states that, generally, projects separated by more than three years based on commencement of construction should not be considered to be part of the same project.\\(^{34}\) The aggregation policy also states that nominally separated projects must also be substantially related in that there must be a technical or economical interconnection between two physical changes, or a “complementary relationship

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\(^{26}\) Id. § 165(a)(3)(B).
\(^{27}\) Id. § 165(a)(3)(C).
\(^{28}\) Id. § 165(a)(6).
\(^{29}\) Id. § 165(a)(7).
\(^{30}\) Ala. Admin. Code r. 335-3-14-.04(1).
\(^{31}\) Id. r. 335-3-14-.04(2)(yy).
\(^{32}\) Id. r. 335-3-14-.04(2)(h) (providing examples within the definition of “commencement”).
\(^{33}\) Id. r. 335-3-14-.04(2)(b).
whereby a change at a plant may exist and operate independently, however its benefit is substantially reduced without the other activity.” One example that EPA gave of substantially related projects was the installation of burners on a utility boiler and a required modification to the air handling system to avoid impairment when operating the new burners. EPA has warned states about aggregating seemingly independent or speculative projects planned over long time periods (5 to 7 years), stating that the source must demonstrate that it is not an attempt to get a “pre-approved check to cash in any time” for projects that are actually “independent from a physical, operational, or economic standpoint.”

Furthermore, EPA has established important conditions on its general rule allowing the staged construction of one or more projects under a single, comprehensive PSD permit, referred to as a phased construction PSD permit. First, only mutually dependent projects should be permitted under a phased construction permit. EPA stated that mutual dependency of projects was a prerequisite to justifying a phased construction permit, and specifically provided that “a three boiler power plant is a typical example of a source with major independent facilities.” In its decision upholding the EPA’s phased construction regulations, the D.C. Circuit stated that “[E]PA regulations . . . suggest, very specifically, that power company multi-boiler construction projects are not mutually dependent . . . .” The D.C. Circuit held that “EPA’s regulations on these matters [are] within the Agency’s statutory authority” and that “EPA’s treatment of utility boilers is not an abuse of discretion.”

Second, a phased construction permit must include (among other things) independent BACT review no later than eighteen months prior to the commencement of construction of each phase; actual commencement of each phase within 18 months (federal regulations) or 24 months (state regulations) of the projected and approved date; and avoidance of any interruption in construction for longer than 18 months (federal regulations) or 24 months (state regulations). The EPA established the above phased construction permits because it was “concerned about the issuance of permits . . . that would have the effect of ‘reserving’ the increment for a single source, thereby limiting growth options in the area.” Similarly, in upholding the phased construction regulations, the D.C. Circuit found that the EPA’s time limits were reasonable because they would “prevent construction projects from reserving, for too long in the future, a disproportionate share of available pollution increments.”

Once a permit has been granted, permittees must commence and complete construction within set time periods. If these time limits are not met, the PSD permit will be invalidated. Alabama Administrative Code rule 335-3-14-.04(17)(a) states:

An Air Permit authorizing construction shall become invalid if construction is not commenced within twenty-four (24) months after receipt of such approval, if construction is discontinued for a period of twenty-four (24) months or more, or if construction is not completed within a reasonable time. The Director may extend the twenty-four (24) month period upon satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within twenty-four (24) months of the projected and approved commencement date.

This regulation is inconsistent with the federal provision, which requires stricter 18 month time periods in place of Alabama’s 24 month periods.\(^{45}\)

### A. ADEM Incorrectly Proposes to Authorize Barry Units 8 and 9 in a Single PSD Permit.

In its permit application, Alabama Power proposes “to construct and operate up to two (2) new natural gas-fired combined cycle (CC) electric generating units located at its Barry Steam Electric Generating Plant (Plant Barry).”\(^{46}\) These two units, as mentioned above, are known as Barry Unit 8 and Barry Unit 9. Each new unit will produce a gross output of approximately \(744\) MW each, with a net output of approximately \(726\) MW.\(^{47}\) According to the application, the units’ construction will be staggered by two years. Alabama Power proposes to commence construction on Unit 8 in March 2021, but not commence construction on Unit 9 until two years later, in March 2023.\(^{48}\) The same is true for the commercial operation date: November 2023 for Unit 8, November 2025 for Unit 9.\(^{49}\)

ADEM should not permit Barry Units 8 and 9 under one PSD permit. First, the two units should not be aggregated in a single PSD permit because they are separate, unrelated stationary sources. According to EPA’s aggregation policy, projects that are substantially related, as in through a technical or economic interconnection, should be aggregated in a single permit. Here, neither Alabama Power in its permit application nor ADEM in its Draft Permit has demonstrated that the units are interrelated. Either can exist and operate independently of the other, and each provides the same benefit regardless of the other (i.e., each will produce 726 MW regardless of whether the other is constructed).\(^{50}\)

Indeed, Alabama Power’s own actions demonstrate that the projects are independent of one another. Before constructing a new power plant, Alabama Power is required to obtain a

\(^{45}\) 40 C.F.R. § 52.21(r)(2).
\(^{46}\) Permit Application at 1-1.
\(^{47}\) Id. at 2-1.
\(^{48}\) Id. at 1-2 (Table 1-1, Milestone Activities).
\(^{49}\) Id.
\(^{50}\) See 74 Fed. Reg. at 2,378.
In addition, Barry Unit 9 cannot meet the time limits required by either Alabama or federal regulations. A PSD permit will become invalid if construction of a facility is not commenced within 24 months of permit issuance. While Alabama Power proposes to commence construction of Unit 8 in March 2021, it does not propose to commence construction of Unit 9 until March 2023, which presumably will be more than 24 months from issuance of the proposed PSD permit. The time limits help ensure that BACT determinations do not become stale and that air modeling analysis conducted for the permit truly reflects the impact of other sources of air emissions in the area. It also helps ensure that the project cannot reserve a disproportionate share of available pollution increments.

Second, Barry Units 8 and 9 cannot be permitted as a phased construction PSD permit. As discussed above, the D.C. Circuit upheld EPA’s limitation on the use of multi-phase permits to only those projects that are mutually dependent. Barry Units 8 and 9 are mutually independent facilities. In fact, they are exactly the kind of facilities that EPA intended to classify as independent facilities. Similar to EPA’s example of a three-boiler power plant being a source with independent facilities, here we have two distinct combined cycle units that are not dependent on each other for construction or operation. Thus, because the two units are mutually independent, Alabama Power should obtain separate PSD permits for each unit.

Even if ADEM can justify Units 8 and 9 being permitted as a phased construction project, the Draft Permit does not include the necessary conditions applicable to multi-phase permits. A phased permit must require BACT to be evaluated before each individual phase and the phases would be subject to specific time requirements. BACT review must occur no later than 18 months prior to commencement of construction of each phase, and actual commencement must occur within 24 months (18 months according to federal regulations) of the projected and approved date.

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53 Order, Ala. Power Co. Petition for Certificate of Convenience and Necessity, Docket No. 32953 (Ala. P.S.C. Aug. 14, 2020). It is important to note that the certificate of convenience and necessity proceeding before the PSC is ongoing. After issuance of the final order, Energy Alabama and Gasp, intervenors in the docket, filed a Petition for Reconsideration and Rehearing. Intervenor Sierra Club also filed a Petition for Reconsideration and Rehearing.
54 Ala. Admin. Code r. 335-3-14-.04(17)(a)
55 Permit Application at 1-2 (Table 1-1).
56 ADEM has not characterized the Draft Permit as a multi-phase permit; however, it appears that ADEM may have intended to issue a multi-phase PSD permit given the various phases proposed to be permitted—Unit 8, Unit 9, the future upgrade to Unit 8, and the future upgrade to Unit 9.
58 See Ala. Admin. Code r. 335-3-14-.04(9)(d), -(17)(a); 40 C.F.R. §§ 52.21(j)(4), -(r)(2).
In sum, the Draft Permit and Preliminary Determination are deficient because they propose to permit Barry Units 8 and 9—two independent facilities built two years apart from one another—under a single PSD permit. If ADEM can justify the permitting of both units as a phased construction project, which it cannot because the projects are mutually independent, then it must include the necessary conditions applicable to a phased construction permit.

B. ADEM Incorrectly Proposes to Authorize Future Upgrades to Barry Units 8 and 9.

Alabama Power not only applied for a PSD permit for the construction of Barry Units 8 and 9 (referred to as the “pre-upgrade units” in this section), but it also requested that the PSD permit approve a future, separate “pre-planned” turbine upgrade (referred to as the “future upgrades” in this section).59 Because the future upgrades are separate projects from the construction of the pre-upgrade units, could result in significant emissions increases in their own right, and will not be constructed until 2027 (for Unit 8) and 2029 (for Unit 9), they require separate permits to be issued closer in time to the proposed turbine upgrade’s commencement of construction. Further, the future upgrades are not clearly defined in the permit application, although the information provided does indicate that the upgrades would make the units less efficient and would result in an increase in hourly heat input capacity.

The Company’s February 2020 permit application describes the combined cycle units as follows:

The [combined cycle (CC)] units installed at Plant Barry will initially produce a gross output of approximately 744 MW each, (net output of approximately 726 MW) at site barometric pressure and humidity, but will be capable of additional output following planned replacement of some of the turbine components. After the turbine upgrade, timed to coincide with typical hot gas path inspection/replacement work for such units, the CC units will produce a gross output of approximately 761 MW (net output of approximately 743 MW) each. Accordingly, the emission calculations presented in Section 3 of this document address both the “pre-upgrade” and “post-upgrade” configurations. The BACT assessment presented in Section 5, focuses conservatively on the long-term future “post-upgrade” configuration of the CC units. The dispersion modeling assessments presented in Section 6 address both the “pre-upgrade” and “post-upgrade” configurations. Maximum annual operation of each CC unit will be 8,760 hours per year.60

The future upgrades to the turbine components will be installed approximately four years after initial commercial operation of the pre-upgrade units.61 Alabama Power describes “milestone activities,” which show the following planned activities and dates:62

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59 Permit Application at 1-2, 2-1.
60 Id. at 2-1.
61 Id. at 1-2 (“Each unit will have installed turbine hardware such that the final capacity can be realized after planned manufacturer’s upgrades to turbine components approximately four years after commercial operation.
62 Id., Table 1-1 Milestone Activities.
The Company further states that “[a]dditionally, the proposed Project will allow for the construction of additional ancillary equipment and/or adjustments or replacements of existing facility support structures or equipment to support the construction of up to two (2) combined cycle units” and that an “overall Project construction schedule” is provided in Appendix B. However, Appendix B has been withheld from the public as Confidential Business Information.

Based on permit application and other publicly-available documents, there is little information that can be gleaned about the future upgrades. However, it is clear that the future upgrades will (1) make the units less efficient (meaning more fuel burned for the same amount of electricity generated); (2) significantly increase the units’ greenhouse gas emissions; and (3) change the dispersion characteristics of the units.

First, the future upgrades will make the units less efficient. They will increase gross generating capacity and the maximum heat input of each unit by about 2.3%, and will increase the annual average hourly heat input by even more, 3.721%. More specifically, the gross generating capacity will increase by 2.285% and the maximum hourly heat input will increase by 2.348%. The higher increase in heat input indicates that the units will become less efficient with the future upgrades.

Second, the future upgrades will significantly increase greenhouse gases being emitted by the units. The Company projects an increase in both the hourly and annual emission rates of carbon dioxide (CO₂). It projects that annual average hourly rates of CO₂ will increase by 3.725% (more than the 2.285% in gross generating capacity)—the pre-upgrade annual average hourly rate for CO₂ for the units is 538,177 lb/hr (723 lb/hr/MW) versus the post-upgrade rate of 558,224 lb/hr (733 lb/hr/MW). Assuming 8,760 hours per year of operation, the upgrade will result in an increase of 87,714 tons per year in potential CO₂ emissions for each Unit, or 175,610 tons per year for both units. This potential increase in emissions after the future upgrades exceeds the ADEM and EPA emission threshold of 75,000 tons per year for defining when an increase in greenhouse gas emissions should trigger PSD applicability.

Third, the future upgrades will change the dispersion characteristics of the emissions units. The permit application notes that there are “slight variations in . . . flue gas exhaust characteristics between the ‘pre’ and ‘post’ upgrade configuration of the combined-cycle” units. However, the specific variations of the flue gas exhaust have been withheld from the public. These variations are purportedly identified in Tables 6-2 and 6-3, but several columns

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63 Permit Application at 1-2.
64 Id. at 2-1 and Appendix D at Tables D-1 and D-5.
65 Id.
66 See Ala. Admin. Code r. 335-3-14-.04(2)(w); 40 C.F.R. § 52.21(b)(49)(iv)(a).
67 Permit Application at 6-2.
(including data on exit temperature, exit velocity, and maximum hourly emissions under various operating scenarios) are redacted in the public version of the permit application.68

The permit application also states that, when the site area land use characteristics were modeled, “the pre-upgrade configuration results in higher modeled concentrations for NO₂ (1-hour and annual), CO (1-hour), and SO₂ (1-hour, 24-hour, and annual), while the post-upgrade configuration results in higher modeled concentrations for CO (8-hour), PM₁₀/PM₂.₅ (24-hour and annual) and SO₂ (3-hour).”69 However, upon close inspection, the modeling results in Table 7-2 indicate that, for the 1-hour NAAQS for NO₂, CO and SO₂, only the operations of baseline plus inlet cooling plus duct burner result in lower pollutant concentrations post-upgrade. All other operations of the combustion turbines without the duct burners actually result in higher pollutant concentrations post-upgrade for the 1-hour average standards. Indeed, operation of the post-upgrade combustion turbines at baseload and with just inlet cooling result in 1-hour NO₂ concentrations that are 5.1% higher than the pre-upgrade 1-hour NO₂ concentrations with the turbines operating at baseline with inlet cooling. These modeling results clearly show that the upgrades will change the dispersion characteristics of the emissions units.

Outside of the information listed and discussed above, which had to be determined by analyzing data in the permit application, the application does not give sufficient detail about the planned future upgrades and additional activities associated with those upgrades. And despite the differences between the pre- and post-upgrade configurations, as set forth above, the Company has only evaluated BACT for the units in their post-upgrade configuration.70

For several reasons, permitting the future upgrades as part of the same project as the pre-upgrade units is inconsistent with PSD permitting requirements. First, the construction of the pre-upgrade units and the future upgrades should not be considered part of one project because of the length of time between the commercial operation of each Unit and the turbine upgrades exceeds 24 months. For instance, Unit 8 is projected to begin operating in November 2023, while the upgrades will not be installed until approximately four years later, August 2027; Unit 9 is two years behind Unit 8. Alabama’s permitting regulations provide that a PSD permit shall become invalid if construction is discontinued for a period of 24 months or more or if construction is not completed within a reasonable time.71 The reason for this limitation is so that BACT determinations do not become stale and so that air modeling done for the permit truly reflects the impact of other sources of air emissions in the area in order for ADEM to find that a proposed new source will not cause or contribute to a violation of the NAAQS or PSD increment. Furthermore, the time limitation ensures that the project cannot reserve a disproportionate share of available pollution increments.

Second, EPA’s aggregation policy supports the argument that the pre-upgrade units and the future upgrades are two separate projects. The future upgrades are projected to occur six years and five months after commencement of construction of each unit, and four years after the commercial operation of each unit, well beyond the three-year timeframe that EPA has stated

68 Id. at 6-4 to 6-5.
69 Id. at 7-1.
70 Id. at 2-1.
71 Ala. Admin. Code r. 335-3-14-.04(17)(a).
indicates that projects are substantially related to each other to be considered as one aggregate project.\(^{72}\) In addition, based on the scant information included in the permit application, the projects are not substantially related, i.e., there is a technical or economic interconnection between the physical changes. Neither the permit nor the application explain any interrelationship between the pre-upgrade units and the upgrades. Indeed, numerous recent PSD permits for new natural gas combined cycles were reviewed in the process of preparing these comments, and none of the permits reviewed allowed for a future, poorly defined turbine upgrade.\(^{73}\) Instead, it appears that Alabama Power wants a permit now to construct the new units and to upgrade those units whenever the manufacturer makes upgrades available. If ADEM intends for the construction of the units and the upgrades to be considered as one project, ADEM must demonstrate that the projects are truly related, from a physical, operational, or economic standpoint. Such an analysis is required given the greater than three-year period from commencement of construction of the units to the planned upgrades.

Finally, as currently proposed, the pre-upgrade units and the future upgrades cannot be considered one single project under a phased construction permit. While ADEM’s regulations allow the use of multi-phase construction permits with specific conditions, including independent BACT review for each phase, these phased construction projects have generally been interpreted as when multiple projects are “mutually dependent”\(^{74}\) and when a source “will contain a number of facilities to be built in a program of phased construction.”\(^{75}\) They are not intended for a future upgrade to a new emissions unit. In any event, it does not appear that ADEM is proposing to approve the combustion turbines and the turbine upgrades as a phased construction project. Neither Alabama Power’s permit application nor ADEM’s preliminary determination mention the project as a phased project.

If ADEM can demonstrate that the pre-upgrade units and the future upgrades are justifiably considered to be one project, then the project should be permitted as a phased construction project. BACT would need to be evaluated for each independent phase of the multi-phase project. BACT will be different for the different phases, because the maximum heat input capacity of the combustion turbines will increase after the turbine upgrades and the efficiency will decrease after the turbine upgrades, based on the data submitted within the permit. Thus, the BACT emission limits (currently proposed in terms of pounds per hour (lb/hr) and pound per million British thermal unit heat input (lb/MMBtu)) will differ for a lower heat input/higher efficiency unit compared to a higher heat input/lower efficiency unit after the turbine upgrades.

The Draft Permit and preliminary determination are thus deficient because they fail to demonstrate that the pre-upgrade units and the future upgrades are sufficiently interrelated to justify authorizing both projects in one permit. Further, if such a relationship can be shown, the permit is deficient in failing to evaluate BACT for the units before the turbine upgrades (in a multi-phase permit). Moreover, the Draft Permit would also be deficient for failing to include

\(^{72}\) See Permit Application at 1-2 (Table 1-1); 83 Fed. Reg. at 57,327.

\(^{73}\) See Table 1 of these comments for a list of the permits reviewed.

\(^{74}\) 43 Fed. Reg. at 26,396.

\(^{75}\) See, e.g., Memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management to Regional Administrators, PSD Regulations – Interpretation of Commencement of Construction (Dec. 18, 1975); 43 Fed. Reg. at 26,396 (referring to phased construction projects as “multifacility sources”).
necessary requirements for a new BACT evaluation for the turbine upgrades which must occur no later than 18 months from the commencement of construction of the turbine upgrades, as well as to ensure that the units and upgrades are constructed no later than 24-months from the projected and approved commencement date (which must also be spelled out in the permit). Because ADEM cannot justify aggregating the pre-upgrade units and the future upgrades as one project, then the permit and emission limits must only be based on the pre-upgrade configuration of the units.

II. Flawed BACT Determinations

As mentioned above, all new major emitting facilities and major modifications to existing facilities must be subject to best available control technology (BACT) before construction can commence. This requirement cannot be met by imposing BACT that fails to comply with the definition in the Clean Air Act.

As defined in the statute, BACT means “an emission limitation based on the maximum degree of [pollutant] reduction . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic costs and other costs, determines is achievable for [the] facility through application of production processes and available methods, systems and techniques . . . for the control of each such pollutant.” These controls include, but are not limited to, “fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques.”

Alabama regulations define “emission limitation” as follows:

[A] requirement, established by ADEM or the EPA Administrator, which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirements which limit the level of opacity, prescribe equipment, set fuel specifications, or prescribe operation or maintenance procedures for a source to ensure continuous emission reduction.

Federal rules and the Clean Air Act define emission limitation in a very similar manner:

*Emission limitation* and *emission standard* mean a requirement established by a State, local government, or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirements which limit the level of opacity, prescribe equipment, set fuel specifications, or prescribe operation or maintenance procedures for a source to assure continuous emission reduction.
More succinctly, the BACT standard requires a new facility or major modification to use the control technology that limits emissions to the lowest level possible, but is still technically feasible and would not impose unacceptably high economic or other secondary costs. To find this control technology, applicants and air permitting authorities must conduct a pollutant-specific, case-by-case analysis that methodically determines the maximum degree of emissions reduction achievable, taking into account the technical feasibility and costs listed above.  

The permitting authority must consider, in determining the BACT, all technology, methods and fuel alternatives from a variety of sources that would limit emissions of the pollutants but do not change the “fundamental scope” of the project. Importantly, BACT is technology-driven and expected to be technology-forcing. Rather than look at what industry leaders have achieved, BACT analysis looks for what technology can achieve and establishes increasingly efficient and effective benchmarks. Simply put, BACT requires “the most current, state-of-the-art pollution controls.” The search for this technology should include an inquiry into technologies at similar sources, using information sources such as the EPA’s RACT/BACT/LAER Clearinghouse. It should also include an inquiry into the possibilities of technology transfer from similar sources.

In addition to determining the control technology, the permitting authority must also determine the corresponding performance level for that technology. Achievable limits can be determined by reviewing manufacturer’s data, engineering estimates and other sources’ experience. When reviewing the emission performance levels of a specific technology, the permitting authority “should conclude that the lower emissions limit is representative for that control alternative” unless it can show “differences between the proposed source and previously permitted sources achieving lower emission limits.” “[I]t is presumed that the source can achieve the same emission reduction as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise.”

As correctly noted in Alabama Power’s permit application, EPA applies a “top down” approach for determining BACT. As described by the EPA:

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84 EPA NSR Manual at B.12 (“[T]o satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control.”).
87 Id. at B.5 (“[T]he control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams…”); see also id. at B.16 (“[T]echnology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.”).
89 Id.
90 Id.
91 See Permit Application at 5.1.
In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent—or “top”—alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.\textsuperscript{92}

The formal steps of the top-down analysis can be described as:

Step 1: Identify all control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Rank remaining control technologies by control effectiveness;
Step 4: Evaluate most effective controls and document results; and
Step 5: Select BACT.\textsuperscript{93}

Permit applicants often attempt to shortcut this top-down BACT analysis in order to arrive at the technology they have pre-selected. It is necessary for the permitting authority to require a full and complete analysis to avoid selecting a control level that is less than BACT.

A. The Proposed NOx BACT Emission Limitations and Associated Requirements Fail to Ensure the Maximum Degree Pollutant Emission Reduction Will Be Met at Barry Units 8 and 9.

For NOx emissions, ADEM proposes BACT limits of 31.9 lb/hr and 0.008 lb/MMBtu for Barry Units 8 and 9, and specifies that compliance with the NOx BACT limits is based on stack testing.\textsuperscript{94} ADEM has also proposed exemptions from these BACT limits during periods of startup, shutdown and load change, which is discussed in detail in Section IIE below.\textsuperscript{95} ADEM claims, without support, 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.”\textsuperscript{96}

The NOx BACT limits for the units fail to meet both the definition of BACT and the definition of “emission limitation.” The limits do not ensure the maximum degree of NOx reduction which has been shown to be achievable for similar sources, nor does the Draft Permit require compliance on a continuous basis with the proposed BACT limits.

\textsuperscript{92} EPA NSR Manual at B.2.
\textsuperscript{93} Id. at Table B-1 (Key Steps in the “Top-Down” BACT Process).
\textsuperscript{95} Draft Permit 503-1001-X014 at 8-9 (Conditions 13 and 18 of Emission Standards, Provisos for Units 8 and 9).
\textsuperscript{96} Preliminary Determination at PDF p. 4.
1. The NOx emission limit will be higher than 2 parts per million by dry volume (ppmvd) at 15% oxygen.

Alabama Power proposed low NOx burners and selective catalytic reduction as BACT for NOx, stating that “[d]uring normal operating conditions, the proposed combined cycle units are guaranteed to meet a NOx emissions level of 2 ppmvd @15% O2 with a maximum emission rate of 39.1 lb/hr for each unit.”97 In the Draft Permit, ADEM proposes a limit of 0.008 lb/MMBtu; however, this proposed limit is actually higher than the 2 ppmvd proposed by Alabama Power.

EPA has set forth an equation for converting from ppm to lb/MMBtu in Appendix F of 40 C.F.R. Part 75:

\[ E = K \times C_h \times F \times (\frac{20.9}{20.9 - \%O_2}) \]

Where

- \( E \) = pollutant emissions in lb/MMBtu during operation
- \( K = 1.194 \times 10^{-7} \) (lb/dscf)/ppm NOx
- \( C_h \) = hourly average pollutant concentration, ppm
- \( \%O_2 \) = oxygen concentration during operation
- \( F = 8,710 \) dscf/MMBtu for natural gas98

Using this equation to solve for \( C_h \), a NOx emission limit of 0.008 lb/MMBtu equates to 2.17 ppmvd at 15% oxygen. Thus, the proposed BACT limit reflects a NOx rate higher than 2 ppmvd and is not as stringent as the limit proposed by Alabama Power or the required NOx BACT for several similar natural gas combined cycle units with low NOx burners and SCR.

2. The proposed NOx BACT limits and monitoring method are less stringent than those required as BACT for similar sources.

EPA’s New Source Review Workshop Manual states that when there are control techniques with a wide range of emissions performance, the most effective level of control must be evaluated in the BACT analysis.99 EPA also states that “it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are relevant information that provide a technical, economic, energy or environmental justification to do otherwise.”100

97 Permit Application at 4-9.
98 40 C.F.R. Part 75, Appendix F, Table 1.
100 Id. at B.24.
A review of EPA’s RACT/BACT/LAER Clearinghouse (RBLC)\textsuperscript{101} shows there have been numerous NOx BACT limits imposed for similar natural gas-fired combined cycle power plant units of 2.0 ppmvd. Table 1 below provides a list of such permits. The most stringent NOx BACT limit required in the RBLC is a 2.0 ppmvd @15% oxygen NOx emission limit applicable on a 1-hour average basis with compliance measured by a continuous emissions monitoring system (CEMS). The list of permits in Table 1 reflect NOx BACT limits of 2.0 ppm on a 24-hour rolling basis or shorter averaging time, with alternative emission limits (i.e., pound per hour or pound per event) for startup and shutdown. Notably, these permits all require CEMS for compliance.\textsuperscript{102}

**Table 1. NOx BACT Emission Limits for Natural Gas-Fired Combined Cycle Power Plants in EPA’s RACT/BACT/LAER Clearinghouse that are More Stringent than Proposed for Plant Barry Units 8 and 9**

<table>
<thead>
<tr>
<th>RBLC ID</th>
<th>Name of Facility</th>
<th>Size of NG-Fired Combined Cycle Units</th>
<th>NOx limit and Averaging Time</th>
<th>Exemptions &amp; Alternative Limits?</th>
</tr>
</thead>
<tbody>
<tr>
<td>VA-0332</td>
<td>Chickahominy Power</td>
<td>319 MW</td>
<td>2.0 ppmvd, 1-hour average, CEMs</td>
<td>Alt. short term emission limits apply during S&amp;S, tuning</td>
</tr>
<tr>
<td>VA-0328</td>
<td>Novi Energy C4GT, LLC</td>
<td>\textless{}4,000 MMBtu/hr (w/duct burner)</td>
<td>2.0 ppmvd, 1-hr average, CEMs</td>
<td>S&amp;S, tuning, water washing, alt emission limits apply</td>
</tr>
<tr>
<td>VA-0325</td>
<td>(VA Electric&amp; Power Co) Greensville Power Station</td>
<td>3227 MMBtu/hr</td>
<td>2.0 ppmvd, 1-hr avg, CEMs</td>
<td>S&amp;S, tuning, and water wash have alternative NOx emission limits.</td>
</tr>
<tr>
<td>CA-1251</td>
<td>Palmdale Energy Project</td>
<td>2217 MMBtu/hr</td>
<td>2.0 ppmvd, 1-hr average, CEMs</td>
<td>S&amp;S, alt NOx emission limits and event limits</td>
</tr>
<tr>
<td>CT-0161</td>
<td>Killingly Energy Center</td>
<td>3,585 MMBtu/hr (w/duct burner)</td>
<td>2.0 ppmvd, 1-hr average, CEMs</td>
<td>S&amp;S, alt. 1-hr block emission limits</td>
</tr>
<tr>
<td>OH-0367</td>
<td>South Field Energy LLC</td>
<td>3,391 MMBtu/hr (w/duct burner)</td>
<td>2.0 ppmvd, 1-hr avg, CEMs</td>
<td>S&amp;S, with lb/hr limits for S&amp;S</td>
</tr>
<tr>
<td>IL-0129</td>
<td>CPV Three Rivers LLC</td>
<td>3,474 MMBtu/hr</td>
<td>2.0 ppmvd 3 unit-hourly average (after 36</td>
<td>S&amp;S, tuning, and commissioning.</td>
</tr>
</tbody>
</table>


\textsuperscript{102} The required use of CEMS is either stated in the RBLC information or, for some permits, was determined by reviewing the PSD permit.
<table>
<thead>
<tr>
<th>State-EPD</th>
<th>Facility Name</th>
<th>Power</th>
<th>NOx Emission Limit</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>IL-0310</td>
<td>Jackson Energy Center</td>
<td>3864 MMBtu/hr</td>
<td>2.0 ppmvd (3-hr rolling average for 1st 36 months, then 1-hr avg), CEMs</td>
<td>Alt. lb/hr limits apply during those timeframes.</td>
</tr>
<tr>
<td>NJ-0085</td>
<td>Middlesex Energy Center</td>
<td>633 MW</td>
<td>2.0 ppmvd, 3-hr rolling avg, CEMs</td>
<td>S&amp;S alt. emission limits</td>
</tr>
<tr>
<td>MI-0442</td>
<td>Thomas Township Energy</td>
<td>625 MW</td>
<td>2.0 ppmvd, 24-hr rolling average, CEMS</td>
<td>Alt. S&amp;S emission limits</td>
</tr>
<tr>
<td>MI-0432</td>
<td>New Covert Generating Co.</td>
<td>1239 MW (3 combined cycle units)</td>
<td>2.0 ppmvd, 24-hour rolling average, rolled hourly, CEMs</td>
<td>S&amp;S, lb/hr limits</td>
</tr>
<tr>
<td>MI-0435</td>
<td>Belle River Combined Cycle Power Plant</td>
<td>1,150 MW (2 combined cycle units)</td>
<td>2.0 ppmvd, 24-hour rolling average, rolled hourly, CEMs</td>
<td>S&amp;S, alt lb/hr limit applies</td>
</tr>
<tr>
<td>MI-0433</td>
<td>Marshall Energy Center</td>
<td>500 MW</td>
<td>2.0 ppmvd, 24-hr rolling average, rolled hourly, CEMs</td>
<td>S&amp;S, lb/hr limits</td>
</tr>
<tr>
<td>MI-0431</td>
<td>Indeck Niles LLC</td>
<td>4161 MMBtu/hr (w/duct burner)</td>
<td>2.0 ppmvd, 24-hr rolling average, rolled hourly, CEMs</td>
<td>S&amp;S, lb/hr limits</td>
</tr>
<tr>
<td>TX-0819</td>
<td>Gaines County Power Plant</td>
<td>426 MW</td>
<td>2.0 ppmvd, rolling 24-hr average, CEMs</td>
<td>S&amp;S, with alt. NOx emission limits</td>
</tr>
<tr>
<td>FL-0367</td>
<td>Shady Hills Energy Center</td>
<td>385 MW</td>
<td>2.0 ppmvd 24-hr block avg, CEMs</td>
<td>S&amp;S subject to NSPS NOx limits</td>
</tr>
</tbody>
</table>

Notes:
“S&S” means startup and shutdown.
All NOx emission limits in ppmvd are at 15% oxygen.

Based on a review the permits for the similar facilities cited in Table 1, there is significant precedent for NOx BACT to be based on a 2.0 ppmvd NOx limit on a 1-hour average measured by CEMS. ADEM’s proposed NOx BACT limit of 0.008 lb/MMBtu, which converts to 2.17 ppmvd @15% oxygen and for which compliance is based on an infrequent stack test, is much less stringent than a 2.0 ppmvd NOx limit for which compliance is determined on an hourly basis using CEMS. Neither Alabama Power nor ADEM have justified a less stringent NOx BACT limit and monitoring method for the proposed Unit 8 and 9 combined cycle power plant units. In contrast, there is ample justification for ADEM to impose a 2.0 ppmvd NOx limit...
on a 1-hour average measured by CEMS, as has been required for at least seven other similar natural gas-fired combined cycle power plant units.

**B. The CO and VOC BACT limits are less stringent than limits required as BACT for similar sources.**

Alabama Power states that its proposed CO and VOC BACT limits are based on the use of oxidation catalyst systems and reflect the vendor guaranteed emission rate of 2 ppmvd @ 15% oxygen, which the Company claims is representative of BACT for similar units.\(^{103}\) ADEM has proposed to accept Alabama Power’s proposed CO and VOC BACT emission limits as at least as stringent as “most of the other BACT determinations for similar sources.”\(^{104}\) The Draft Permit allows an exemption from BACT limits during startup, shutdown, and load changes, which is discussed in section II.E below.

Despite ADEM’s statements, these limits are less stringent than limits required as BACT for similar sources. As stated above, when there are control techniques with a wide range of emissions performance, the most effective level of control must be evaluated in the BACT analysis, unless there is a demonstration showing differences between the proposed source and the previously permitted sources.\(^{105}\)

As illustrated in Table 2 below, there are at least five other BACT determinations for similar natural gas-fired combined cycle units with lower CO BACT limits than 2.0 ppmvd and four BACT determinations with lower VOC limits than 2.0 ppmvd. As Table 2 shows, the basis for Alabama Power’s proposed CO BACT limit is twice as high as the lowest CO BACT limits (which is 1.0 ppmvd, applicable on a 3-hour rolling average basis) and is more than twice as high as the lowest VOC BACT limits (which is 0.70 ppmvd, 3-hour average). Neither Alabama Power nor ADEM has put forth any justification as to why these significantly lower emission limits that have been required at similar natural gas-fired combined cycle units could not be met at Plant Barry Units 8 and 9.

**Table 2. CO and VOC BACT Emission Limits for Natural Gas-Fired Combined Cycle Power Plants in EPA’s RACT/BACT/LAER Clearinghouse that are More Stringent than Proposed for Plant Barry Units 8 and 9**

<table>
<thead>
<tr>
<th>RBLC ID</th>
<th>Name of Facility</th>
<th>Size of NG-Fired Combined Cycle Units</th>
<th>CO Limit and Averaging Time</th>
<th>VOC Limit</th>
<th>Exemptions &amp; Alternative Limits?</th>
</tr>
</thead>
<tbody>
<tr>
<td>VA-0332</td>
<td>Chickahominy Power</td>
<td>319 MW</td>
<td>1.0 ppmvd, 3-hr rolling avg, CEMS</td>
<td>0.70 ppmvd, 3-hr avg</td>
<td>Alt. short term emission limits apply during S&amp;S, tuning</td>
</tr>
<tr>
<td>VA-0328</td>
<td>Novi Energy C4GT, LLC</td>
<td>~4,000 MMBtu/hr</td>
<td>1.0 ppmvd, 3-hr rolling avg</td>
<td>0.70 ppmvd, 3-</td>
<td>S&amp;S, tuning, water washing,</td>
</tr>
</tbody>
</table>

\(^{103}\) Permit Application at 5-9 to 5-10; 5-11.

\(^{104}\) Preliminary Determination at PDF p. 8.

\(^{105}\) See EPA NSR Manual at B.23 to B.24.
### Table

<table>
<thead>
<tr>
<th>Code</th>
<th>Project Name</th>
<th>Emissions (MMBtu/hr)</th>
<th>CEMS</th>
<th>HR Avg</th>
<th>Alt Emission Limits Apply</th>
</tr>
</thead>
</table>
| VA-0325
(VA Electric & Power Co)
Greensville Power Station | 3227 (w/duct burner) | 1.6 ppmvd, 3-hr avg (w/duct burner)
1.0 ppmvd, 3-hr avg (w/o duct burner) | 1.64 ppmvd (w/duct burner)
0.70 ppmvd (w/o duct burner) | S&S, tuning, and water wash have alternative NOx emission limits. |
| CA-1251
Palmdale Energy Project | 2217 MMBtu/hr | 1.5 ppmvd, 1-hr, w/o duct firing (after demo period).
2.0 ppm, 1-hr, with duct firing (after demo period) | NA | S&S, alt. NOx emission limits and event limits |
| CT-0161
Killingly Energy Center | 3,585 MMBtu/hr (w/duct burner) | 1.7 lb/MMBtu, 1-hr block (w/duct)
0.9 ppmvd, 1hr, w/o duct firing) | 1.6 ppmvd (w/duct)
0.7 ppmvd (w/o duct firing) | S&S, alt. 1-hr block emission limits |

Notes:
“S&S” means startup and shutdown.
All CO and VOC emission limits in ppmvd are at 15% oxygen.

Further, while the Draft Permit does not require use of CEMS for CO, at least two facilities’ CO BACT determinations (Chickahominy Power and Novi Energy C4GT) require CO CEMS to be used to assure continuous compliance. The Draft Permit does require the oxidation catalyst inlet temperature to be monitored continuously with the temperature to be kept above 625 degrees Fahrenheit, but ADEM’s Preliminary Determination does not explain how this requirement ensures continuous compliance with the CO BACT limit.

Thus, ADEM’s proposed BACT emission limits for CO and VOC have not been adequately justified. ADEM must instead impose a CO emission limit consistent with 1.0 ppmvd at 15% oxygen on a 3-hour average basis and a VOC limit consistent with 0.70 ppmvd at 15% oxygen on a 3-hour average basis, or ADEM must justify why those limits are not achievable at Plant Barry Units 8 and 9.

**C. The SO2 BACT limit is less stringent than limits required as BACT for similar sources.**

Alabama Power has proposed an SO2 BACT limit of 0.00168 lb/MMBtu for Barry Units 8 and 9, which it claims reflects a natural gas sulfur content of 0.6 grains per 100 standard cubic

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106 Draft Permit 503-1001-X014 at 11.
feet.\footnote{107} ADEM has, inexplicably, proposed a higher, less stringent SO$_2$ BACT limit than what Alabama Power proposed of 0.002 lb/MMBtu in the Draft Permit.\footnote{108} ADEM states that “[a] review of the RBLC revealed that the proposed control design would provide SO$_2$ control that is at least as stringent as most of the other BACT determinations for similar sources.”\footnote{109}

However, a review of BACT determinations in the EPA’s RBLC shows that much lower SO$_2$ emission limits have been required as BACT. Limits as low as 0.0011 lb/MMBtu have been required as BACT for SO$_2$ at the Chickahominy Power facility, the Novi Energy C4GT facility, and the Greensville Power Station (RBLC ID Nos. VA-0332, VA-0328, and VA-0325, respectively). In addition, the SO$_2$ BACT limit for the Southfield Energy facility is 0.0014 lb/MMBtu (RBLC ID No. OH-0367), and the SO$_2$ BACT limit for Killingly Energy Center is 0.0015 lb/MMBtu (RBLC No. CT-0161). ADEM must provide a justification for imposing a higher BACT limit than these limits for similar sources, including providing an explanation of why it imposed an SO$_2$ BACT limit higher than the 0.00168 lb/MMBtu SO$_2$ BACT limit proposed by Alabama Power.

ADEM also excludes periods of startup, shutdown, and load change from compliance with its proposed SO$_2$ BACT limits for Plant Barry Units 8 and 9.\footnote{110} As discussed in Section II.E below, there is no justification for allowing Units 8 and 9 any alternative emission limits or exemptions from SO$_2$ BACT during these periods, because SO$_2$ BACT is based solely on sulfur content of the fuel and will not be affected by startup, shutdown, or load change.

D. ADEM has not adequately evaluated BACT for greenhouse gas emissions, and its proposed BACT limits fail to reflect BACT for greenhouse gas emissions.

According to ADEM’s GHG BACT analysis, Alabama Power identified and evaluated energy efficiency; use of low carbon fuels; and carbon capture, utilization and storage (CCUS) as CO$_2$ emission controls.\footnote{111} From that evaluation, Alabama Power proposed energy efficient design, practices and procedures and the use of natural gas to meet BACT for GHG, and ADEM proposes limits of 1,000 lb CO$_2$/Megawatt-hour (MW-hr) gross and an annual CO$_2$ equivalent (CO$_{2e}$) limit for each combined cycle unit of 2,445,022 tons per year as BACT (for a combined total of 4,890,044 tons per year).\footnote{112} Compliance with the tons per year limit appears to be a calendar total of CO$_{2e}$ emissions, while compliance with the 1,000 lb CO$_2$/MW-hr gross limit is based on a 12-month rolling average basis.\footnote{113}

As discussed above, the BACT standard requires a new facility or major modification to use the control technology that limits emissions to the lowest level possible, but is still technically feasible and would not impose unacceptably high economic or other secondary costs. In determining BACT, ADEM must consider all technology, methods and fuel alternatives from

107 Permit Application at 5-13.
108 Draft Permit 503-1001-X014 at 8 (Condition 14 of Emission Standards).
109 Preliminary Determination at PDF p. 5.
110 Id. at 8-9.
111 Preliminary Determination at PDF p. 11.
112 Id. at PDF p. 12.
113 Draft Permit 503-1001-X014 at 8 (Conditions 7 and 8 of Emission Standards) for Units 8 and 9.
a variety of sources that would limit emissions of the pollutants but would not change the “fundamental scope” of the project.114

Here, ADEM has failed to conduct a proper top-down analysis of BACT for GHG emissions for Barry Units 8 and 9. ADEM should have considered additional GHG emission control alternatives. While Alabama Power considered CCUS in its BACT analysis for GHG emissions, there are other GHG emission reduction methods that should have been identified and evaluated beyond “energy efficient design” and “use of natural gas” to meet BACT for GHG emissions. The following examples demonstrate the kinds of technically feasible control options that should have been identified and evaluated in determining BACT for Barry Units 8-9.

ADEM and Alabama Power should have evaluated hybrid solar options as a GHG control option for the new Barry Units 8 and 9. One such solar-gas hybrid in operation in the United States is Florida’s Martin Next Generation Solar Energy Center.115 These types of facilities achieve improved overall efficiency by using concentrated solar power to provide a separate line of steam to the steam turbine, which will displace some of the fossil fuel input requirements of the combined cycle units and thus decrease CO$_2$e emissions. As the Department of Energy’s National Renewable Energy Laboratory explains, concentrated solar power (CSP) “is unique in its ability to integrate with existing fossil fuel generation systems.”116

Another option that ADEM and Alabama Power should have evaluated as BACT for GHG is a hybrid battery storage design. Several turbine vendors are offering this option.117 In 2017, Southern California Edison and GE began operating the first battery-turbine gas hybrid in California.118

There are other examples of energy efficient design that have been implemented in natural gas-fired combined cycle power plants. For example, the Warren County Power Station in Virginia, completed in December 2014, is a 1,300 MW gas-fired combined cycle power plant with three combustion turbine generators and three heat recovery steam generators. This plant “uses a thermal energy storage system (TES) designed to produce chilled water in off-peak periods, when electricity rates and demand are lower . . . . During peak electrical demand, the chilled water is pumped from the tank to the inlet air coils of the gas turbines to reduce the inlet air temperature to 50 degrees F, increasing the capacity of the plant.”119 The Warren County Power Station was awarded the Gas-Fired Project of the Year and overall Project of the Year for

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2015 by *Power Engineering* and *Renewable Energy World* for, among other things, the plant’s very efficient heat rate which is driven by its thermal energy storage system and chillers which reduce parasitic load during peak demand. A review of its CO₂ emissions per gross-megawatt-hour based on emissions and gross load submitted to EPA’s Air Markets Program Database, shows that the 12-month average lb CO₂/gross MW-hr rates average between 803 to 806 lb/MW-hr per unit. That reflects a CO₂ emission rate almost 20% lower than the 1,000 lb/MW-hr gross BACT limit proposed by ADEM.

In addition, the more stringent CO₂ BACT limits for similar sources demonstrate the ability to achieve greater control of GHG. ADEM’s proposed 1,000 lb/MW-hr gross limit is the same as the New Source Performance Standards (NSPS) limit in 40 C.F.R. Part 60 Subpart TTTT. The NSPS is considered the BACT floor, in that no BACT limit may be less stringent than the NSPS limit, but ADEM is still required to evaluate more stringent BACT requirements.

Table 3 below identifies those limits as well as heat rate limits (in terms of British thermal unit/kilowatt-hour (Btu/kW-hr)) that have often been imposed as BACT limits in addition to lb CO₂/MW-hr limits. Many of the limits have been imposed in CO₂ emitted per net MW-hr. For comparison, EPA allows a 1,030 lb/MW-hr net limit to apply as an alternative to the NSPS limit of 1,000 lb/MW-hr gross.

### Table 3. CO₂ BACT Emission Limits for Natural Gas-Fired Combined Cycle Power Plants in EPA’s RACT/BACT/LAER Clearinghouse that are More Stringent than Proposed for Plant Barry Units 8 and 9

<table>
<thead>
<tr>
<th>RBLC ID</th>
<th>Name of Facility</th>
<th>Size of NG-Fired Combined Cycle Units</th>
<th>GHG limit and Averaging Time</th>
<th>2nd GHG Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>MI-0435</td>
<td>Belle River Combined Cycle Power Plant</td>
<td>1,150 MW (2 combined cycle units)</td>
<td>2,042,773 tpy, 12-month rolling</td>
<td>794.0 lb CO₂/MW-hr gross, 12-month rolling avg</td>
</tr>
<tr>
<td>MI-0433</td>
<td>Marshall Energy Center</td>
<td>500 MW</td>
<td>1,978,297 tpy, 12-month rolling</td>
<td>806 lb CO₂/MW-hr gross, 12-month rolling avg</td>
</tr>
<tr>
<td>VA-0332</td>
<td>Chickahominy Power</td>
<td>319 MW</td>
<td>812.0 lb CO₂/MW-hr net, 12-month rolling total.</td>
<td>6,452.0 Btu/kW-hr net, initial heat rate test. Limit increases over</td>
</tr>
</tbody>
</table>

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121. See Ex. 1, Warren County Power Station monthly emissions data from EPA’s Air Markets Program Database from January 2016 through June 2020.

122. See Ala. Admin. Code r. 335-3-14-.04(2)(l) (defining BACT).
ADEM’s proposed BACT limit of 1,000 lb/MW-hr gross for Plant Barry Units 8 and 9 will not encourage efficient operation of the units. As Table 3 demonstrates, there are numerous PSD permits with lower BACT limits than the proposed 1,000 lb/MW-hr gross limit. There are also several examples of BACT limits, often imposed as secondary BACT limits, based on plant heat rate not exceeding a certain level in terms of Btu/kW-hr (net).

ADEM’s use of the NSPS limit as BACT for CO₂e wholly insufficient. BACT is to be determined on a case-by-case basis following a top-down approach, starting with the most effective control technologies and emission reduction techniques/processes and resulting in a BACT emission limitation that reflects the maximum degree of emission reduction that can be achieved at the source taking into account energy, environmental, and economic impacts. Given

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the numerous other similar sources with more stringent GHG BACT emission limits, ADEM has failed to propose a BACT emission limit for Plant Barry Units 8 and 9 that reflects anything close to what has been required of other similar natural gas-fired combined cycle units.

With respect to the Draft Permit’s other GHG limit of 2,445,022 tons per year of CO₂e, there is nothing in the permit record showing that this reflects BACT. In fact, ADEM’s proposed annual GHG BACT limit is equivalent to the post-turbine upgrade, full load “worst-case” annual emissions of CO₂ identified in the Plant Barry permit application.¹²⁴ In developing an annual GHG emission limit to reflect BACT, ADEM should not simply impose a worst-case GHG emission limit reflective of the units’ potential to emit. Instead, ADEM should establish an annual limit that is truly intended to limit GHG emissions from the combined cycle units.

ADEM must conduct a proper, top-down analysis of BACT for GHG emissions from Plant Barry Units 8 and 9, considering a solar hybrid option, an energy storage (battery or other type of energy storage) option, and the most energy efficient operation to ensure GHG emissions are minimized to the maximum extent possible. Further, as discussed in Section I.B above, ADEM must evaluate and establish GHG BACT for the combined cycle units as they will initially be constructed (i.e., pre-turbine upgrade).

E. The Draft Permit unlawfully sets no emission limits for NOx, SO₂, CO, VOCs and PM during startup, shutdown and load change.

For periods of startup, shutdown and load change, the Draft Permit does not require any emission limits for NOx, SO₂, CO, VOCs and PM (both PM₁₀ and PM₂.₅). Instead, the Draft Permit requires only vague and unenforceable measures during these periods. Specifically, the Draft Permit requires the following work practice standards to apply during startup, shutdown, and load change in lieu of complying with BACT emission limits:

(a) The permittee shall take all reasonable actions to minimize the magnitude and duration of emissions during the periods listed above.

(b) Employ good operation and maintenance practices on the Turbines and Duct Burners, including on associated pollution control technology.

(c) Comply with emissions monitoring, recordkeeping, and reporting requirements in this permit.

(d) During periods of startup of the CT, the permittee shall, consistent with technological limitations, manufacturers’ specifications, and good engineering and maintenance practices for SCR, initiate reagent flow in the SCR once the flue gas reaches the requisite temperature for NOx control.

¹²⁴ Permit Application, Appendix D at Table D-5.
(e) During periods of startup of the DB and periods of shutdown of the DB the permittee shall maintain reagent flow in the SCR consistent with technological limitations, manufacturers’ specifications, and good engineering and maintenance practices for SCR and so as to minimize NOx emissions to the extent reasonably practicable.

(f) During periods of shutdown of the CT, the permittee shall, consistent with technological limitations, manufacturers’ specifications, and good engineering and maintenance practices for SCR, maintain reagent flow in the SCR until the flue gas temperature falls below the requisite temperature for NOx control.125

Along with these work practice standards, the Draft Permit requires submittal of information to indicate the percent of time the emission limits are exceeded during startup, shutdown and load change.126 However, these requirements only apply to NOx emissions.127 The permit also defines startup, shutdown and load change.128 Load change is defined in a particularly vague and open-ended way as a “change in heat input that creates a transient operating condition that is readily identifiable on the load chart recording.”129

Instead of requiring Alabama Power to comply with such vague and unenforceable work practice standards, ADEM must set alternative emission limits or not allow any exemptions during periods of startup and shutdown. These proposed work practice standards are vague and provide significant flexibility to Alabama Power without providing assurance that emissions will be minimized during these periods. Indeed, the Draft Permit does not require any compliance methods and procedures other than a requirement to operate and maintain the Units in a manner consistent with good air pollution control practices for minimizing emission. And the recordkeeping and reporting provisions only apply to the percentage of time in which emissions limits were exceeded. They require no information to be submitted that would indicate whether Alabama Power minimized the magnitude and duration of exceedances, such as the time period for startup, shutdown, or tuning event, or the reagent flow to the SCR.

More importantly, BACT is an “emission limitation,” which is defined as a requirement that limits the rate of emissions “on a continuous basis.”130 It is feasible to impose alternative emission limits that apply during periods of startup and shutdown as demonstrated by numerous PSD permits for combined cycle power plants that impose alternate emission limitations, rather than exemptions from numerical emission limitations, during startup and shutdown.

125 Draft Permit 503-1001-X014 at 9 (Condition 18(a)-(f) of Emission Standards, Unit 8 and Unit 9 Provisos).
126 See id. at 11-12 (Condition 1 of Recordkeeping and Reporting Requirements).
127 Id.
128 Id. (Condition 19 of Emission Standards).
129 Id. (Condition 19(c) of Emission Standards).
130 Ala. Admin. Code r. 335-3-14-.03(2)(a)1.
For NOx, CO and VOC emissions, ADEM should impose emission limitations reflective of BACT during startup and shutdown at Barry Units 8 and 9. The permits listed in Tables 1 and 2 actually set alternative emission limitations in terms of pounds of NOx or CO allowed per hour or pounds of NOx or CO per event. In addition, many of the permits listed in Table 1 impose limits on the duration and frequency of these startup and shutdown events. For example, in the PSD permit for the Palmdale Energy Center in California, issued by EPA Region 9, EPA set NOx and CO emission limits as well as time duration limits for cold startups, warm startups, hot startups, and shutdowns.\textsuperscript{131} The PSD permit issued for Killingly Energy Center establishes pound per hour limits for startup and shutdown on NOx, VOC, and CO emissions.\textsuperscript{132} The PSD permit for Chickahominy Power Station limits the duration of startups and shutdowns in minutes per event, and limits the pounds of NOx, CO, and VOC emissions per startup and shutdown event.\textsuperscript{133} These are just a few of the numerous examples of permits that actually impose emission limitations to reflect BACT during startup and shutdown.

For SO2, PM\textsubscript{10} and PM\textsubscript{2.5} emissions, no exemption from BACT requirements should be authorized. A review of several of the RBLC entries for the sources listed in Table 1 finds that permitting authorities have generally established alternative emission limits for startup and shutdown for the NOx, CO, and VOC, but have not established alternative emission limits or allowed exemptions from BACT for PM or SO2 BACT limits. That is because BACT for PM (PM\textsubscript{10} and PM\textsubscript{2.5}) and SO2 at natural gas-fired combined cycle power plants is based on burning pipeline quality natural gas with low sulfur content, and the effectiveness of that pollution control does not vary during periods of startup and shutdown.

ADEM must also remove any exemption from emission limits for load changes because there is simply no justification for this proposed exemption. The permit’s definition of load change is vague, overly broad, and unenforceable. Allowing exemptions whenever a “change in heat input . . . creates a transient operating condition that is readily identifiable on the load chart recording”\textsuperscript{134} could result in Alabama Power failing to comply with the BACT emission limits a high percentage of time without violating its permit, depending on how often there is a “transient operating condition.” Moreover, without continuous emissions monitoring, it is impossible to know when and by how much Alabama Power is exceeding its emission limits. A review of the permits for sources listed in Table 1 shows that none of the permits for combined cycle power plants allow alternative emission requirements for load changes.

In sum, ADEM has not provided an adequate justification for its broad exemptions from BACT emission limits during periods of startup, shutdown and load change at Barry Units 8 and 9. Rather than exempting periods of startup or shutdown from any emission limitations, ADEM must propose NOx, CO, and VOC emission limits for these periods that reflect BACT for these periods for the combustion turbines of Units 8 and 9. ADEM cannot justify any exemptions from BACT emission limits for PM or SO2. Thus, it must require the Company to comply with those

\textsuperscript{131} See Ex. 2, Palmdale Energy PSD Permit at 6-7 (Condition 19).
\textsuperscript{132} See Ex. 3, Conn. Dep’t of Envtl. Protection, Permit Number 089-0107, NTE Connecticut, Killingly Energy Center, at 6 (June 30, 2017) [hereinafter Killingly Energy Center PSD Permit].
\textsuperscript{133} See Ex. 4, Va. Dep’t of Envtl. Quality, Permit Registration Number 52610, Chickahominy Power, LLC, Chickahominy Combined-Cycle Power Plant Project, at 12-13 (June 24, 2019) [hereinafter Chickahominy PSD Permit].
\textsuperscript{134} Draft Permit 503-1001-X014 at 9 (Condition 19(c) of Emission Standards).
emission limits at all times. Finally, given that other similar sources do not have exemptions from BACT emission limits for load changes, and that neither Alabama Power nor ADEM have justified or documented the need for such exemptions, the exemption from BACT limits for load changes is inconsistent with BACT for natural gas combined cycle facilities. ADEM must remove “load change” from its exemption in Emission Standards Proviso 18 of the Draft Permit.

III. Flawed Air Modeling

Under the CAA, construction on a new major emitting facility or major modification, such as Barry Units 8 and 9, may not be commenced unless “the owner or operator of such facility demonstrates . . . that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year.” According to the EPA, “[t]he main purpose of this air quality analysis is to demonstrate that new emissions emitted from a proposed major stationary source or major modification, in conjunction with other applicable emissions increases and decreases from existing sources . . . will not cause or contribute to a violation of any applicable NAAQS or PSD increment” and that ambient impacts of pollutants not covered by the NAAQS also cause no statutory harm. “A separate air quality analysis must be submitted for [all] regulated pollutant[s] . . . [which] include (1) pollutants for which a NAAQS exists (criteria pollutants) and (2) other pollutants, which are regulated by EPA, for which no NAAQS exist (noncriteria pollutants).” The modeling used to gauge these impacts must comply with the EPA implementing regulations, and Alabama regulations that are part of its SIP.

A. The NO₂, CO, and Ozone air modeling failed to take into account emissions during startup, shutdown, and load changes.

Alabama Power’s modeling performed to assess the Barry Units 8 and 9’s compliance with the NAAQS and the PSD increments did not take into account emissions during startup, shutdown, or load change, all of which are currently exempt from BACT emission limits. Because emissions during these periods will be significantly higher than during other levels of operation, ADEM should not issue the PSD permit without modeling that shows that the allowable emissions in the permit will not cause or contribute to violations of the NAAQS or PSD increments.

Modeling that includes emissions during startup, shutdown, and load change is particularly important to assure compliance with the 1-hour average NO₂ NAAQS, the 1-hour and 8-hour CO NAAQS, and the ozone NAAQS. NOx and CO emissions will be significantly higher during startup and shutdown, and VOC emissions will be higher during startup. Appendix D of the Company’s PSD permit application indicates the following maximum emission rates

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135 CAA § 165(a)(3)(A); see Ala. Admin. Code r. 335-3-14-.04(10)(a).
136 EPA NSR Manual at C-1.
137 Id.
138 40 C.F.R. § 52.21
139 Ala. Admin. Code r. 335-3-14-.04.
during startup compared to the worst-case hourly emission rates of 100% load (with duct firing and inlet conditioning):

Table 4. Plant Barry Units 8 and 9: Alabama Power’s Maximum Hourly NOx and CO Emission Rates During Startup Compared to Worst Case NOx and CO Emissions at 100% Load

<table>
<thead>
<tr>
<th></th>
<th>Pre-Turbine Upgrade</th>
<th>Post-Turbine Upgrade</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NOx, lb/hr</td>
<td>CO, lb/hr</td>
</tr>
<tr>
<td>Max During Startup</td>
<td>102.0</td>
<td>1,673.6</td>
</tr>
<tr>
<td>100% Load plus duct</td>
<td>38.0</td>
<td>23.1</td>
</tr>
<tr>
<td>firing (and inlet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>cooling)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>% Increase in hourly</td>
<td>168.4%</td>
<td>7,145.0%</td>
</tr>
<tr>
<td>rate during startup</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>109.4</td>
<td>1676.7</td>
</tr>
<tr>
<td></td>
<td>39.1</td>
<td>23.8</td>
</tr>
</tbody>
</table>

Alabama Power did not provide worst case hourly VOC emissions during startup, but VOC emissions are also expected to be much higher during startup and shutdown. Not only will startup emissions have high emissions of these pollutants, but the stack gas temperature and flue gas velocity will be lower, which will lower the plume rise and result in greater impact to ground-level pollutant concentrations during these time periods as compared to 100% load conditions.

It is assumed that startup emissions reflect the worst case hourly emission rates that would be allowed under the terms of the Draft Permit, given that the Draft Permit exempts such time periods from compliance with BACT emission limits. However, the Draft Permit also exempts periods of load change from BACT emission limits. Alabama Power has not presented any emissions estimate for emissions of the combined cycle power plant units during load changes. ADEM must require Alabama Power to provide such data.

It is not clear why ADEM did not require modeling of worst-case startup emissions. Startup and shutdown are part of the normal operation of natural gas-fired combined cycle units and will occur throughout the year. Startup and shutdown of natural gas-fired combined cycle units such as Plant Barry Units 8 and 9 are projected to occur with sufficient frequency that emissions during such periods could significantly impact 1-hour NO2 concentrations and 1-hour and 8-hour average CO concentrations throughout the year. Indeed, Alabama Power indicates that each unit could have 25 cold starts per year (which likely would not occur on the same day, thus at least two days per month on average), 34 warm starts, and 111 hot starts, as well as 170 shutdowns. Given that the form of the 1-hour average NO2 NAAQS is the 98th percentile (8th highest) daily maximum hourly NO2 concentration and that startups could occur on

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140 Id. at Table 6-4 and Appendix D at Tables D-1 and D-5.
141 Permit Application, Appendix D at Table D-5.
142 40 C.F.R. 50.11(f).
approximately half of the days in a year, startup emissions could impact the facility’s compliance with the 1-hour NO2 NAAQS. The 8-hour average CO NAAQS is based on an even more stringent form of the standard, as the NAAQS are not to be exceeded more than once per year.  

Modeling of startup emissions to assess impacts on the 1-hour NO2 NAAQS and the CO NAAQS is commonly done for PSD permits for new natural gas-fired combined cycle power plants. For example, in its Fact Sheet for the PSD permit for Palmdale Energy Project, EPA Region IX presented modeling of “Maximum Project Impacts” which included Startup modeling for the CO NAAQS and the 1-hour average NO2 NAAQS. Modeling for the 1-hour average NO2 NAAQS and the CO NAAQS was also conducted for the PSD permit for the Chickahominy natural gas-fired combined cycle power plant.

For all of these reasons, the Permit Application for Plant Barry Units 8 and 9 is deficient. As required by ADEM’s regulations, ADEM should not issue the PSD permit without modeling to show that the allowable emissions under the permit will ensure that Plant Barry Units 8 and 9 will not cause or contribute to a NAAQS or PSD increment violation over all levels of operation at the source.

B. The 1-hour NO2 modeling should have been based on NO2 data from a closer, more representative background monitoring location.

A PSD permit application must include an analysis of ambient air quality in the vicinity of the proposed project for each pollutant subject to PSD review. This ambient air quality data is used to develop representative background concentrations that are then used in the NAAQS compliance analysis.

Alabama Power used background monitoring for 1-hour NO2 concentrations from Yorkville, Georgia. Yorkville, Georgia is approximately 270 miles from Plant Barry. Yet, there are two ambient air NO2 monitoring stations in Birmingham, Alabama which is much closer, at approximately 180 miles from Plant Barry. In addition, the 1-hour NO2 concentrations at the closer monitoring stations are higher than the background concentration of 1-hour NO2 used in the NO2 NAAQS analysis for Plant Barry Units 8 and 9. This is shown in Table 5 below.

143 The sum of Alabama Power’s projected cold starts, warm starts, and hot starts is 170. Assuming those starts occur on separate days, startup emissions could occur on 47% of the days in a year. Permit Application at 3-2.

144 40 C.F.R. § 50.8.


147 See Ala. Admin. Code r. 335-3-14-.04(10)(a).

148 40 C.F.R. § 52.21(m); Ala. Admin. Code r. 335-3-14-.04(12).

149 Permit Application at 6-16.
Table 5. Nearby 1-hour NO2 Monitoring Sites Compared to 1-Hour NO2 Monitoring Background Concentration Used in Alabama Power’s 1-Hour NO2 NAAQS Analysis for Plant Barry Units 8 and 9

<table>
<thead>
<tr>
<th>Monitoring Site</th>
<th>Monitoring Site ID</th>
<th>Year</th>
<th>98th Percentile Daily Max 1-Hour NO2 Concentration, ppb</th>
<th>3-Year Avg of 98th Percentile Daily Max 1-Hour NO2 Concentration, ppb</th>
</tr>
</thead>
<tbody>
<tr>
<td>Birmingham, AL</td>
<td>10730023</td>
<td>2017</td>
<td>38</td>
<td></td>
</tr>
<tr>
<td>Birmingham, AL</td>
<td></td>
<td>2018</td>
<td>38</td>
<td></td>
</tr>
<tr>
<td>Birmingham, AL</td>
<td></td>
<td>2019</td>
<td>45</td>
<td>40.3</td>
</tr>
<tr>
<td>Birmingham, AL</td>
<td>10732059</td>
<td>2017</td>
<td>43</td>
<td></td>
</tr>
<tr>
<td>Birmingham, AL</td>
<td></td>
<td>2018</td>
<td>45</td>
<td></td>
</tr>
<tr>
<td>Birmingham, AL</td>
<td></td>
<td>2019</td>
<td>50</td>
<td>46.0</td>
</tr>
<tr>
<td>Background Monitoring Site used by Alabama Power</td>
<td>Assumed to be</td>
<td>Assumed to be from years:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Yorkville, GA</td>
<td>132230003</td>
<td>2013</td>
<td>18</td>
<td></td>
</tr>
<tr>
<td>Yorkville, GA</td>
<td></td>
<td>2014</td>
<td>17</td>
<td></td>
</tr>
<tr>
<td>Yorkville, GA</td>
<td></td>
<td>2015</td>
<td>13</td>
<td>16</td>
</tr>
</tbody>
</table>

The specific NO2 monitoring site and years of data used in deriving the background 1-hour NO2 concentration utilized in Alabama Power’s NO2 modeling was not provided in the permit application. However, a review of EPA’s air data air monitor values website found that there was a 1-hour average NO2 monitor operating in Paulding County, Georgia listed as operating at 160 Ralph King Path in Rockmart, Georgia, which is within five miles of Yorkville, Georgia, with monitoring site ID 132230003. That monitor did not operate after 2015, and the three-year average of the most recent three years of 98th percentile daily maximum 1-hour NO2 concentrations is 16 parts per billion—the same background concentration used by Alabama Power in its 1-hour NO2 modeling. So it is assumed that monitor site ID 132230003 was used for the 1-hour NO2 background concentration in Alabama Power’s modeling analysis.

The EPA’s Guidelines on Air Quality Modeling state that the background concentration should be based on the most recent, nearby monitoring site that is closest to and upwind from the project. The 1-hour NO2 monitoring sites in Birmingham have much more recent data than the Yorkville, Georgia site, the sites are 90 miles closer than the Yorkville site, and the Birmingham sites, being north-northeast of the Plant Barry site, are upwind based on the wind rose provided.

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150 For data presented in this table, see Outdoor Air Quality Data Monitor Values Report, Env’tl. Protection Agency, https://www.epa.gov/outdoor-air-quality-data/monitor-values-report (last visited Oct. 19, 2020); see also Permit Application at 6-16.
152 Permit Application at 6-16.
153 40 C.F.R. Part 51, Appendix W, Section 8.3.
in Alabama Power’s Permit Application.¹⁵⁴ While the EPA modeling guidelines state that a regional site for background concentration can be justified, such a site should be “impacted by similar or adequately representative sources.”¹⁵⁵ No such justification for using the much lower background concentration at the Yorkville, GA site has been provided in Alabama Power’s permit application or in ADEM’s Preliminary Determination. Given the significant difference in the background concentration used in Alabama Power’s 1-hour NO₂ NAAQS analysis compared to the nearest, most recent, upwind monitoring sites in Birmingham, ADEM must justify use of the Yorkville data from 2013-2015 as representative of the background hourly NO₂ concentrations in the vicinity of Plant Barry.

This is especially important because there are several other sources of NOx pollution in the vicinity of Plant Barry, and it is not clear whether all such sources were included in the cumulative 1-hour NO₂ modeling analysis. A review of the EPA’s 2017 National Emission Inventory data shows that the nearby sources of NOx emissions include U.S. Amines (chemical plant), Arkema (chemical plant), Nouryon Functional Chemicals, LLC, Lenzing Fibers, Inc., FMC Agricultural Solutions, SSAB Alabama, Inc. (steel mill), Hilcorp Energy Company (oil or gas facility), Florida Gas Transmission Company (compressor station), and AM/NS Calvert LLC (steel plant), among others.¹⁵⁶ These facilities appear to be within ten miles of Plant Barry. In comparison, Paulding County in Georgia has only three NOx sources listed in the 2017 National Emissions Inventory: Paulding County regional airport, Paulding Memorial Hospital, and Caffrey airport.¹⁵⁷ Thus, it is likely that the background 1-hour NO₂ concentrations in the area around Plant Barry are significantly higher than the background 1-hour NO₂ concentrations at the Yorkville, GA NO₂ monitoring site.

It is unlikely that Alabama Power modeled all of these sources that could likely be impacting hourly NO₂ concentrations in the vicinity of Plant Barry. According to Alabama Power’s permit application, ADEM provided an inventory of off-site sources “based on significant impact area distances,” which is defined as “the further distance from the source that modeled concentrations exceed the [significant impact level(SIL)].”¹⁵⁸ While the permit application does not appear to identify how far out from the source the significant impact area extended for 1-hour NO₂ concentrations, a review of the concentration isopleth figures in Appendix K of the permit application indicates that the significant impact radius was likely less than one mile from the Plant Barry boundary. Thus, presumably, ADEM did not identify any of the sources listed above from the 2017 National Emissions Inventory to be modeled with the Plant Barry 1-hour average NO₂ NAAQS analysis. However, the fact that these sources of NOx emissions exist in the vicinity of Plant Barry justifies the use of a much more conservative NO₂ background monitoring concentration than from the Yorkville, Georgia, which is based on monitoring data that is five to seven years old and is from a monitoring site approximately 270 miles away in an area with far fewer industrial sources of NOx emissions. Thus, ADEM should require the use of a more appropriate and representative background NO₂ monitoring background

¹⁵⁴ Permit Application at 6-20, Figure 6-4.
¹⁵⁵ 40 C.F.R. Part 51, Appendix W, Section 8.3.2.b.
¹⁵⁷ Id.
¹⁵⁸ Permit Application at 8-1.
concentration that is more reflective of the other sources of NOx emissions in the vicinity of Plant Barry.

C. Alabama Power did not model peak hourly NOx emissions at Units 6A, 6B, 7A, and 7B at Plant Barry in its 1-hour NO2 modeling analysis.

While Alabama Power’s permit application does not clearly identify all of the sources modeled in the cumulative NAAQS assessments, it is clear that the modeling analysis did include the existing Plant Barry units. However, a review of hourly emissions data for Plant Barry Units 6A, 6B, 7A, and 7B shows that the maximum hourly NOx emissions are much higher than what was modeled for these units in the cumulative 1-hour NO2 modeling analysis. One year of emissions data from 2019 for the Plant Barry units—the most recent year for which a full year of hourly emissions data is available in EPA’s Air Program Markets Database—was analyzed and that review indicated that the emissions modeled by Alabama Power for Units 6A, 6B, 7A, and 7B were significantly understated. This is shown in Table 6 below.

<table>
<thead>
<tr>
<th>Plant Barry Existing Unit</th>
<th>2019 Peak NOx Emissions, lb/hr</th>
<th>Alabama Power’s Modeled NOx Emissions, lb/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>6A</td>
<td>193.6</td>
<td>27.7</td>
</tr>
<tr>
<td>6B</td>
<td>221.9</td>
<td>27.7</td>
</tr>
<tr>
<td>7A</td>
<td>157.8</td>
<td>27.7</td>
</tr>
<tr>
<td>7B</td>
<td>204.9</td>
<td>27.7</td>
</tr>
</tbody>
</table>

A review of the recently proposed Title V renewal permit for Plant Barry shows that the permit does not impose any NOx emission limits on these four natural gas-fired combined cycle power units during periods of startup, shutdown, or load changes. And a review of the 2019 hourly emissions data for the combined cycle Units 6A, 6B, 7A, and 7B shows that emissions in excess of 27.7 lb/hr at each unit occurred 24-42 hours in each year per unit. In addition, there were 67 hours in 2019 during which the total hourly NOx emissions of all four units exceeded the total of the modeled 27.7 lb/hr per unit (that is, exceeded 110.8 lb/hr). Those 67 hours of the sum total of Units 6A, 6B, 7A, and 7B NOx emissions exceeding 110.8 lb/hr occurred on 31 separate days in 2019, throughout all months of the year. In fact, the maximum hourly sum total of Units 6A, 6B, 7A, and 7B NOx emissions in 2019 was 288.5 lb/hr, which is 2.6 times higher than the 110.8 lb/hr total emissions modeled for these units in the cumulative 1-hour NO2 NAAQS analysis. Clearly, the exemptions from NOx emissions allowed by the Title V permit for Plant Barry Units 6A, 6B, 7A, and 7B actually result in significantly higher hourly NOx emissions on a regular basis throughout the year than what was modeled for these units in the cumulative 1-hour NO2 modeling for the Units 8 and 9 PSD permit.

160 Permit Application at 8-2 (Table 8-1).
Based on a review of a plot plan for the existing Plant Barry and the information in the permit application, Units 6A, 6B, 7A, and 7B will be the closest existing units at Plant Barry to the new Units 8 and 9, and all of these combined cycle power units are close to the western border of the ambient air boundary.\textsuperscript{162} Indeed, the proposed new units are quite close to a historical park on the west side of the property, Ellicott’s Stone Historical Park.\textsuperscript{163} While all ambient air to which the public has access must be treated as worthy of protection from elevated pollutant concentrations, the fact that a historical park is adjacent to the Plant Barry property through which the public can walk to view a historically significant landmark should underscore the need to adequately evaluate maximum expected air pollutant concentrations. Indeed, while the modeled 1-hour NO\textsubscript{2} concentration isopleth figures in Alabama Power’s February 2020 permit application are difficult to interpret, it appears (and seems logical) that the maximum hourly NO\textsubscript{2} concentrations occur directly to the west of the proposed new units.\textsuperscript{164}

The EPA’s Guideline on Air Quality Models requires that, for short term NAAQS modeling assessments for PSD permits, nearby sources be modeled at maximum allowable emission rates.\textsuperscript{165} As discussed in Section II.E above, startup and shutdown at combined cycle power units are part of the normal operation of the units and occur with enough frequency that permitting authorities routinely model such emissions for impacts on the NAAQS. For the same reasons, the peak hourly actual NO\textsubscript{x} emissions from the existing Units 6A, 6B, 7A, and 7B that occur under the terms of the existing permit for these units should also be modeled in the cumulative modeling assessment. Each Unit 6A, 6B, 7A, and 7B is allowed to exceed its NO\textsubscript{x} emission limits during startup, shutdown, and load change and clearly has done so as is demonstrated in the review of 2019 emissions data discussed above. Further, given that there is no nearby 1-hour NO\textsubscript{2} monitoring site that could be deemed as reflecting emissions of the other Plant Barry units, it is imperative that the existing units be modeled at realistic worst-case emission rates. ADEM must require Alabama Power to adequately model the maximum allowable hourly NO\textsubscript{x} emissions from the existing Plant Barry units as well as from the proposed new Plant Barry Units 8 and 9 to adequately demonstrate whether the proposed new units will cause or contribute to a violation of the 1-hour NO\textsubscript{2} NAAQS, as mandated by Alabama’s PSD permitting rules.\textsuperscript{166} Until such a revised analysis is completed and is made available for public review and comment, the PSD permit for Units 8 and 9 should not be granted.

\textsuperscript{162} See Ala. Power Co., Title V Operating Permit Application, Barry Steam Electric Generating Plant, at PDF p. 30 (Feb. 5, 2016) (showing plot plan for existing units); see also Permit Application at 6-21 (Figure 6.5).
\textsuperscript{163} See Ellicott’s Stone, The Historical Marker Database, https://www.hmdb.org/m.asp?m=104073 (last visited Oct. 20, 2020); see also Permit Application at 6-11.
\textsuperscript{164} Permit Application at Appendix K.
\textsuperscript{165} See Table 8-2 of 40 C.F.R. Part 51, Appendix W.
\textsuperscript{166} See Ala. Admin. Code r. 335-3-14-04 (10)(a) (requirement to demonstrate that the allowable emissions from the proposed modification in conjunction with all other applicable emissions increases or reductions would not cause or contribute to a violation of any NAAQS) and (11)(a) (requirement that all estimates of ambient concentrations are based on the requirements in EPA’s Guideline on Air Quality Models).
IV. The Draft Permit for Plant Barry Units 8 and 9 Lacks the Specificity that is Needed to Ensure an Effective PSD Construction Permit.

The Draft Permit lacks certain key elements that are necessary for an effective and enforceable permit that authorizes construction of Units 8 and 9 in accordance with PSD permitting requirements, as discussed below.

First, the Draft Permit does not identify the maximum generating capacity and maximum hourly heat input of the combined cycle units, nor does it identify the model of the combined cycle units. The Draft Permit also does not identify the heat input capacity of the duct burners. If it is justified and appropriate to aggregate the units with the future turbine upgrades as one project, then the permit must identify the maximum generating capacity of the combined cycle units and maximum heat input capacity of the duct burners before the turbine upgrade and after the turbine upgrade. An effective permit would include these technical specifications.167 EPA states in its New Source Review Workshop Manual that:

Overall, the technical specifications may be considered the core of the permit in that they specifically identify the emissions unit(s) covered by the permit and the corresponding emission limits with which the source must comply. Properly identifying each emissions unit is important so that (1) inspectors can easily identify the unit in the field and (2) the permit leaves no question as to which unit the various permit limitations and conditions apply. Identification usually includes a brief description of the source or type of equipment, size or capacity, model number or serial number, and the source’s identification of the unit.168

The permits attached as exhibits to these comments include details such as hourly heat input capacity, generating capacity, and turbine make and model.169 The Draft Permit for Plant Barry Units 8 and 9 also should include these details on each unit, both pre- and post-upgrade (if it is adequately demonstrated that the Project can be aggregated).

Second, the Draft Permit does not refer to the permit application submitted by Alabama Power. EPA’s New Source Review Manual states that the permit “should specify that the application is, in essence, part of the permit.”170 EPA states that these “provisions articulate the contract-like nature of a permit in that the permit allows a source to emit air pollution only if certain conditions are met.”171 ADEM must add a provision to the General Permit Provisos of the Draft Permit stating something similar to what is stated in the Palmdale Energy Project PSD Permit:

The Permittee shall construct the Source and operate equipment listed in this permit . . . in compliance with this permit, the application on which the permit is

167 Id. at H.4 to H.5.
168 Id. at H.5.
169 See, e.g., Ex. 2, Palmdale Energy PSD Permit at 2; Ex. 4, Chickahominy PSD Permit at 2-3; Ex. 3, Killingly Energy Center Permit at 2.
171 Id.
based, and all other applicable federal, state, and local air quality regulations . . . .”\textsuperscript{172}

One of the many reasons this is important is to ensure the integrity of the air modeling which ADEM has relied on, including the units’ proposed location, stack height, diameter, velocity, and exit temperature. Indeed, the EPA’s PSD permit for Palmdale Energy Project also identified the stack height and diameter of each unit in the unit description section of the permit.\textsuperscript{173}

Third, ADEM’s regulations require Alabama Power to apply for a Title V permit within twelve months after commencing operation.\textsuperscript{174} The Draft Permit does not refer to this regulation, but does state in General Permit Proviso 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.

Because the Draft Permit incorrectly includes multiple projects within a single PSD permit, as discussed at length in Section I, the Draft Permit’s Proviso is vague and unenforceable. Furthermore, the Draft Permit does not include any mention of the requirement to apply for Title V permit modification once the facilities commence operation. The Draft Permit should specify which projects require notification to the Chief of the Air Division and submittal of a Title V permit modification application. The permit modification application should be submitted after each separate individual project—Unit 8, Unit 9, future upgrade for Unit 8, and future upgrade for Unit 9.

Fourth, the Draft Permit must incorporate the milestone dates that are provided in Table 1-1 of Alabama Power’s permit application. ADEM should require Alabama Power to provide notification when it commences and finished the various activities listed in the table. The dates for commencing the activities are important because of the various time requirements in the PSD regulations. For instance, construction must be commenced within 24 months after a permit issuance.\textsuperscript{175} In the event ADEM proposes a phased construction permit, these time limits are even more important due to the specific conditions applicable to phased construction permits, such as conducting BACT review no later than 18 months prior to commencement of construction of each phase.

\textsuperscript{172} See Ex. 2, Palmdale Energy PSD Permit at 4 (Condition 8).
\textsuperscript{173} Id. at 2.
\textsuperscript{174} Id. r. 335-3-16-.04(2) (“Sources subject to . . . preconstruction review under Title I of the Act must apply for a permit under this Chapter within 12 months after commencing operation, except, when an existing permit issued under this Chapter prohibits construction or a change in operation, a permit revision must be obtained before commencing operation.”).
\textsuperscript{175} Id. r. 335-3-14-.04(17)(a).
V. The Draft Permit does not include all “Source Obligation” Requirements.

The Draft Permit states that the permit “expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.”\textsuperscript{176} This provision is based on the “Source Obligation” requirements of the PSD regulations.\textsuperscript{177} However, there are other “Source Obligation” requirements in the PSD regulations that ADEM has not specifically included in the Draft Permit. ADEM should add to General Permit Proviso 9 that the air permit will become invalid if construction is discontinued for a period of 24 months or more or if construction is not completed within a reasonable time.\textsuperscript{178} This is especially important if ADEM justifies the future turbine upgrades as properly being aggregated within the construction of the NGCC units.

CONCLUSION

As currently written, the PSD Permit proposed for Barry Unit 8 and 9 Combined Cycle Project should be denied. In light of the Draft Permit’s numerous flaws, illegalities and deficiencies, Commenters respectfully request that ADEM review the Alabama Power permit application anew, requiring Alabama Power to supplement its application as indicated in these comments. ADEM should then propose a new Draft Permit that corrects the serious flaws discussed above for full public review and comment.

Respectfully submitted,

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Christina Andreen Tidwell
Staff Attorney
Southern Environmental Law Center
2829 2\textsuperscript{nd} Avenue South, Suite 282
Birmingham, Alabama 35212
Tel: (205) 745-3060
Email: CTidwell@selcal.org

\textit{On behalf of Energy Alabama, Gasp, Mobile Baykeeper, and Sierra Club}

\textsuperscript{176} Draft Permit 503-1001-X014 at 2 (General Permit Proviso 9).
\textsuperscript{177} Ala. Admin. Code r. 335-3-14-.04(17)(a).
\textsuperscript{178} See id.
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Prevention of Significant Deterioration Permit
Pursuant to Clean Air Act Title I, Part C and 40 CFR 52.21

PSD Permit: SE 17-01
Permittee: Palmdale Energy, LLC
(subsidiary of Summit Power Group, LLC)
801 Second Ave., Suite 1150
Seattle, WA 98104

Source Name: Palmdale Energy Project
Source Location: 950 East Avenue M, Palmdale CA - West of the NW corner of Air Force Plant 42, and East of the intersection of Sierra Highway and East Avenue M

Pursuant to the provisions of the Clean Air Act (CAA) in subchapter I, part C, and the Code of Federal Regulations (CFR) Title 40, Section 52.21, the United States Environmental Protection Agency Region 9 (EPA) is issuing a Prevention of Significant Deterioration (PSD) permit to Palmdale Energy, LLC (or Permittee). This permit applies to the construction and operation of a new natural gas-fired combined-cycle power plant known as the Palmdale Energy Project (PEP or Source).

Palmdale Energy, LLC is authorized to construct and operate the PEP as described herein, in accordance with its PSD permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR 52.21, and other terms and conditions set forth in this PSD permit. Failure to comply with any condition or term set forth in this permit may result in enforcement action pursuant to section 113 of the CAA. This permit does not relieve Palmdale Energy, LLC from the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR parts 51, 52, 60, 61, 63, and 72 through 75), or other federal, state, and local requirements.

Per 40 CFR 124.15(b), this permit shall become effective 30 days after the service of notice of the final permit decision unless review is requested on the final permit under 40 CFR 124.19.

Elizabeth Adams
Acting Director, Air Division

Date: April 25, 2018
Source Description and Equipment List

The Source will have an electrical output of 645 megawatts (nominal output at average annual conditions).

The Source will be located on a parcel of land, currently zoned for industrial use, in the city of Palmdale, in Los Angeles County, California. The approximately 50-acre parcel is west of the northwest corner of Air Force Plant 42, and east of the intersection of Sierra Highway and East Avenue M. The Source is located within the Antelope Valley Air Quality Management District (AVAQMD).

This PSD permit requires the use of Best Available Control Technology (BACT) to limit emissions of nitrogen oxides (NOX), carbon monoxide (CO), total particulate matter (PM), particulate matter less than or equal to 10 micrometers (μm) in diameter (PM10), particulate matter less than or equal to 2.5 μm in diameter (PM2.5), and greenhouse gases (GHG). This permit includes emission limits to ensure that air pollution emissions from the Source will not cause or contribute to violations of any National Ambient Air Quality Standards (NAAQS) or any applicable PSD increments for the pollutants regulated under this PSD permit.

Equipment List:

<table>
<thead>
<tr>
<th>Emissions Unit</th>
<th>Description</th>
<th>Control Equipment Authorized by this Permit</th>
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<tbody>
<tr>
<td>GEN1</td>
<td>214 MW combustion turbine generator (CTG), with a maximum heat input rate of 2,217 MMBtu/hr (HHV, at ISO conditions); natural gas-fired Siemens SGT6-5000F; vents to a dedicated Heat Recovery Steam Generator (HRSG) and a 276 MW Steam Turbine Generator (STG) shared with GEN2; 160-ft stack height; 22-ft stack diameter</td>
<td>Dark Low-NOX (DLN) combustors, selective catalytic reduction (SCR), an oxidation catalyst, and inlet air filtration</td>
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<td>GEN2</td>
<td>214 MW CTG, with a maximum heat input rate of 2,217 MMBtu/hr (HHV, at ISO conditions); natural gas-fired Siemens SGT6-5000F; vents to a dedicated HRSG and a 276 MW STG shared with GEN1; 160-ft stack height; 22-ft stack diameter</td>
<td>DLN combustors, SCR, an oxidation catalyst, and inlet air filtration</td>
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<tr>
<td>DB1</td>
<td>193.1 MMBtu/hr (HHV) Duct Burner for GEN1, fired on natural gas</td>
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<td>DB2</td>
<td>193.1 MMBtu/hr (HHV) Duct Burner for GEN2, fired on natural gas</td>
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<td>D1</td>
<td>110 MMBtu/hr (HHV) Auxiliary Boiler fired on natural gas; 60-ft stack height; 3-ft stack diameter</td>
<td>Ultra-low-NOX burner</td>
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<td>2,011 hp Emergency Generator Engine, fired on ultra-low sulfur diesel fuel; 20-ft stack height; 8-inch stack diameter</td>
<td>40 CFR Part 60, Subpart III emission standards</td>
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<td>D3</td>
<td>140 hp Emergency Fire Pump Engine, fired on ultra-low sulfur diesel fuel; 19.5-ft stack height; 5-inch stack diameter</td>
<td>40 CFR Part 60, Subpart III emission standards</td>
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<td>Six enclosed-pressure SF6 Circuit Breakers</td>
<td>10% (by weight) leak detection system</td>
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<td>FUG</td>
<td>Fugitive methane from equipment leaks</td>
<td>Leak detection and repair program</td>
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Permit Terms and Conditions

Section 1: General Provisions

1. **Permit Expiration**
   As provided in 40 CFR 52.21(r), unless the PSD permitting authority issues an extension of time pursuant to 40 CFR 52.21(r)(2), this PSD permit shall become invalid if:
   a. Construction is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the EPA’s final PSD permit takes effect; or
   b. Construction is discontinued for a period of 18 months or more; or
   c. Construction is not completed within a reasonable time.

2. **Agency Notifications**
   The Permittee shall send all reports and notifications required to be submitted to the EPA by this permit to the mail and email addresses below. All reports and notifications sent by mail must be postmarked by the applicable due date identified in this permit. With prior written notification, the EPA may waive the requirement to submit a hardcopy by mail or may update the mail or emailing addresses specified below.

   EPA Region 9  
   Director, Enforcement Division  
   Attn: Air & TRI, ENF-2-1  
   75 Hawthorne Street  
   San Francisco, CA 94105-3901

   Email: AEO_R9@epa.gov

   With a copy to:
   Air Pollution Control Officer  
   Antelope Valley Air Quality Management District  
   (per the method(s) and address(es) specified for the Permittee’s notifications to the AVAQMD in the Authority to Construct and/or title V operating permit issued by the AVAQMD to the Permittee)

3. **Initial Notifications**
   The Permittee shall notify the EPA of the:
   a. Date construction is commenced, within 30 days of such event;
   b. Actual date of initial startup, as defined in 40 CFR 60.2, within 15 days of such event;
   c. Date upon which initial performance tests will commence, in accordance with the provisions in Condition 41, not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol(s) required pursuant to Condition 40; and
   d. Date upon which initial performance evaluation of the continuous emissions monitoring system (CEMS) will commence in accordance with 40 CFR 60.13(c), not less than 30 days prior to such date. Notification may be provided with the submittal of the CEMS performance test protocol required pursuant to Condition 40.

4. **Source Operation**
   At all times, including periods of startup, shutdown, shakedown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the Source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA which may
include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the Source.

5. **Inspection and Entry**
The EPA Regional Administrator, and/or his or her authorized representative, upon the presentation of proper credentials, shall be permitted to:
   a. Enter upon the premises where the Source is located or emissions-related activity is conducted; or where records are required to be kept under the terms and conditions of this permit;
   b. Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of this permit;
   c. Inspect, during normal business hours or while the Source is in operation, any facilities, equipment (including monitoring and air pollution control equipment), method, practices or operations regulated or required under this permit;
   d. Sample or monitor substances, emissions, or parameters subject to the requirements in this permit; and
   e. Record any inspection by use of written, electronic, magnetic and photographic media.

6. **Transfer of Ownership**
Prior to any transfer of ownership of the Source, the Permittee shall provide a copy of this permit to the new owner(s). In the event of any change in ownership of the Source, the Permittee must notify the EPA as soon as possible but in no case later than 30 days after the change in ownership is effective. This notification to the EPA must specify the date on which ownership was transferred, identify the previous owner, and update the name, street address, mailing address, contact information, and any other information about the ownership and/or operation of the Source that will change as a result of the change in ownership. The Permittee shall ensure that the Source remains in compliance with this permit during any such transfer of ownership.

7. **Severability**
The provisions of this permit are severable. If any portion of this permit is held invalid, the remaining terms and conditions of this permit shall remain valid and in force.

8. **Adherence to Application and Compliance with other Environmental Laws**
The Permittee shall construct the Source and operate equipment listed in this permit (see Equipment List above) in compliance with this permit, the application on which this permit is based, and all other applicable federal, state, and local air quality regulations. This permit does not release the Permittee from any liability for compliance with other applicable federal, state, and local environmental laws and regulations, including the Clean Air Act.

9. **Compliance**
The Permittee must comply with all provisions of this permit. Noncompliance with any permit provision is a violation of the permit and the CAA, and is grounds for an enforcement action.

10. **Unavailable Defense**
In an enforcement action, it shall not be a defense for the Permittee that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the provisions of this permit.

11. **Property Rights**
The permit does not convey any property rights of any sort or any exclusive privilege.

12. **Credible Evidence**
For establishing whether the Permittee violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source
would have been in compliance with applicable requirements if the Permittee had performed the appropriate performance or compliance test or procedure.

13. **Shakedown Period**
   The emission limits and requirements in Conditions 18, 19, and 22 shall not apply during the shakedown period. Shakedown is defined as the period beginning with initial startup, as defined in 40 CFR 60.2, and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the equipment. The shakedown period shall not exceed 180 consecutive days. The requirements of Condition 16 shall apply at all times.

14. **Notification of Closure**
   The Permittee must submit a report of any permanent or indefinite closure to EPA in writing within 90 days after the cessation of any operations at the permitted source. It is not necessary to submit a report of closure for regular, seasonal closures.

15. **Signature Verifying Truth, Accuracy, and Completeness**
   All reports required by this permit shall be signed by a responsible official as to the truth, accuracy, and completeness of the information. The report must state that, based on information and belief formed after reasonable inquiry, the statements and information are true, accurate, and complete. If the Permittee discovers that any reports or notification submitted to the reviewing authority contain false, inaccurate, or incomplete information, the Permittee shall notify the reviewing authority immediately and correct or amend the report as soon as is practicable.

**Section 2: Emission Limitations and Work Practice Standards**

16. **Air Pollution Control Equipment and Operation**
   As soon as practicable following initial startup of the CTGs (startup as defined in 40 CFR 60.2) but prior to commencement of commercial operation (as defined in 40 CFR 72.2), and thereafter, except as allowed below in Condition 19, the Permittee shall install, operate, and maintain the SCR systems for control of NO\textsubscript{X} emissions and the oxidation catalysts for control of CO emissions from GEN1 and GEN2. The Permittee shall also perform any necessary operations to minimize emissions so that emissions are at or below the emission limits specified in this permit for GEN1 and GEN2.

17. **Gaseous Fuel Requirements**
   For each CTG (GEN1 and GEN2) and the auxiliary boiler (D1), the Permittee shall use California Public Utilities Commission (PUC)-quality natural gas. The sulfur content of the gas shall not exceed 0.20 grains per 100 dry standard cubic feet (dscf), based on a 12-month rolling average, and shall not exceed 1.0 grains per 100 dscf at any time.

18. **Combustion Turbine Generator (CTG) Emission Limits**
   On and after the date of initial startup, the Permittee shall not discharge or cause the discharge of emissions from each CTG unit (GEN1 and GEN2) into the atmosphere in excess of the limits specified in this Condition 18. These limits do not apply to NO\textsubscript{X} and CO emissions during startup and shutdown periods; instead, the limits in Condition 19 apply during such periods.
   a. Concentration-based limits:
      i. 2.0 ppmvd of NO\textsubscript{X} @ 15% O\textsubscript{2} based on a 1-hr average;
      ii. 0.0048 lb/MMBtu of PM, PM\textsubscript{10}, and PM\textsubscript{2.5} based on the average of three stack test runs; and
      iii. 928 lb/MWh\textsubscript{net} of CO\textsubscript{2} based on a 12-month rolling average. This limit includes contributions from duct firing (DB1 and DB2, as applicable) and the MWh contribution from the steam turbine generator.
b. Mass-based limits:
   i. 18.5 lb/hr of NO\textsubscript{X} with the associated duct burner firing (DB1 or DB2, as applicable) based on a 1-hr average;
   ii. 17.1 lb/hr of NO\textsubscript{X} without the associated duct burner firing (DB1 or DB2, as applicable) based on a 1-hr average; and
   iii. 11.8 lb/hr of PM, PM\textsubscript{10}, and PM\textsubscript{2.5} based on the average of three stack test runs.

c. CO Emission Limits – The Demonstration Period is defined as the first 5 years immediately following the commencement of commercial operations (as defined in 40 CFR 72.2).
   i. The Permittee shall design the CTGs to each achieve a CO emission rate of 1.5 ppmvd @ 15% O\textsubscript{2} and 7.8 lb/hr based on a 1-hr average without duct firing (DB1 or DB2, as applicable). Prior to beginning actual construction, the Permittee shall submit a design plan to the EPA demonstrating that the CTGs are designed to achieve such a rate and setting forth the measures that will be taken to maintain the oxidation catalyst system and optimize its performance.
   ii. During the Demonstration Period, the Permittee shall operate the CTGs according to the design plan submitted to the EPA described above in Condition 18.c.i. During the Demonstration Period, the Permittee shall not discharge or cause the discharge of CO emissions from either CTG unit (GEN1 or GEN2) into the atmosphere in excess of the following amounts, based on a 1-hr average:
      1. 2.0 ppmvd CO @ 15% O\textsubscript{2}, and
      2. 11.3 lb/hr with duct firing (DB1 or DB2, as applicable) or 10.4 lb/hr without duct firing (DB1 or DB2, as applicable).
   iii. Following the Demonstration Period, the Permittee shall not discharge or cause the discharge of CO emissions from each CTG Unit (GEN1 or GEN2) into the atmosphere in excess of the following amounts based on a 1-hr average, except as specified in Condition 18.c.iv:
      1. 1.5 ppmvd @ 15% O\textsubscript{2} without duct firing (DB1 or DB2, as applicable);
      2. 2.0 ppmvd @ 15% O\textsubscript{2} with duct firing (DB1 or DB2, as applicable);
      3. 7.8 lb/hr without duct firing (DB1 or DB2, as applicable); and
      4. 11.3 lb/hr with duct firing (DB1 or DB2, as applicable).
   iv. If, during the Demonstration Period, the Permittee determines that the CO limits in Condition 18.c.iii.1 or 18.c.iii.3 are not feasible, the Permittee shall submit an application at least 6 months prior to the end of the Demonstration Period requesting a revision of such limit(s). Such application must contain data and information that demonstrates that the Source was operated according to the design plan identified above in Condition 18.c.i, as well as a technical justification explaining why such lower limits are not feasible. Upon the EPA’s review of such an application (which will include an opportunity for public notice and comment), if the EPA determines that the data and information gathered during the Demonstration Period demonstrate that different CO limit(s) are necessary, the limits in Condition 18.c.iii.1 and/or 18.c.iii.3 will be revised accordingly. Provided that the application specified in this condition is postmarked at least 6 months prior to the end of the Demonstration Period, the corresponding emission limit(s) in Condition 18.c.ii.1 and/or 18.c.ii.2 shall remain in effect until the EPA evaluates the application and makes a final decision regarding the revision of the limits in Condition 18.c.iii.1 and/or 18.c.iii.3.

19. CTG Requirements during Gas Turbine Startup and Shutdown (GEN1 and GEN2)
   The following limits apply separately to each CTG, GEN1 and GEN2:
   a. Startup is defined as the period beginning with ignition and lasting until either the equipment complies with the emission limits in Conditions 18.a.i, ii, and iii, as applicable, for 10 one-minute averaging periods or the maximum time allowed for the event after ignition as specified in Condition 19.c, whichever occurs first. Additionally:
i. A cold startup occurs when the STG rotor temperature is less than 485°F after a CTG shutdown;
ii. A warm startup occurs when the STG rotor temperature is greater than or equal to 485°F but less than 685°F after a CTG shutdown; and
iii. A hot startup occurs when the STG rotor temperature is greater than 685°F after a CTG shutdown.

b. Shutdown is defined as the period beginning with reducing fuel flow below normal operating mode and lasting until fuel flow is completely shut off and combustion has ceased.

c. The emissions of NO\textsubscript{X} and CO during startup and shutdown events, and the duration of such events, shall not exceed the following, as verified by the CEMS:

<table>
<thead>
<tr>
<th></th>
<th>NO\textsubscript{X}</th>
<th>CO</th>
<th>Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold Startup</td>
<td>51.5 lb/event</td>
<td>416 lb/event</td>
<td>39 minutes</td>
</tr>
<tr>
<td>Warm Startup</td>
<td>46.8 lb/event</td>
<td>378 lb/event</td>
<td>35 minutes</td>
</tr>
<tr>
<td>Hot Startup</td>
<td>43.2 lb/event</td>
<td>305 lb/event</td>
<td>30 minutes</td>
</tr>
<tr>
<td>Shutdown</td>
<td>33.0 lb/event</td>
<td>75.9 lb/event</td>
<td>25 minutes</td>
</tr>
</tbody>
</table>

d. During startup and shutdown periods, emissions of NO\textsubscript{X} shall not exceed 53.6 lb/hr based on a 1-hr average.
e. During startup and shutdown periods, emissions of CO shall not exceed 419 lb/hr based on a 1-hr average.

20. **CTG Fuel Use Limit**
The total annual fuel use of natural gas for each CTG, GEN1 and GEN2, shall not exceed 1.735 x 10\textsuperscript{10} standard cubic feet (scf) per year based on a 12-month rolling total.

21. **Duct Burner Fuel Use Limit**
The total annual fuel use of natural gas for each duct burner (DB1 and DB2) shall not exceed 2.75 x 10\textsuperscript{8} scf per year based on a 12-month rolling total. The Permittee shall ensure that the duct burners are not operated unless the associated gas turbine units are in operation.

22. **Auxiliary Boiler Emission Limits**
The Permittee shall not discharge or cause the discharge of emissions from the auxiliary boiler, unit D1, into the atmosphere in excess of the following, and shall otherwise comply with the following limits and specifications:
   a. NO\textsubscript{X} emissions shall not exceed 9 ppmvd @ 3% O\textsubscript{2} based on a 3-hr average;
   b. CO emissions shall not exceed 50 ppmvd @ 3% O\textsubscript{2} based on a 3-hr average;
   c. PM, PM\textsubscript{10}, and PM\textsubscript{2.5} emissions shall not exceed 0.007 lb/MMBtu based on a 3-hr average;
   d. As described in Condition 23, the Permittee shall perform a biennial boiler tune up;
   e. Unit D1 shall not operate during normal operations of GEN1 or GEN2, except during periods of, or immediately following, startup. Unit D1 shall be shut down as soon as practicable after the completion of any startup process, as defined in Condition 19.a.
   f. Total annual fuel use of natural gas for Unit D1 shall not exceed 5.25 x 10\textsuperscript{8} scf per year based on a 12-month rolling total.

23. **Auxiliary Boiler Biennial Tune-ups**
Unit D1 shall undergo biennial tune-ups and meet the associated requirements of Condition 48 as follows (if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of the first startup following that date):
   a. Inspect the burner, and clean or replace any components of the burner as necessary (the Permittee may delay the burner inspection until the next scheduled unit shutdown, but must inspect each burner at least once every 36 months).
   b. Inspect the flame pattern, and adjust the burner as necessary to optimize the flame pattern. The adjustment shall be consistent with the manufacturer's specifications.
c. Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly (the Permittee may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection).

d. Optimize total emissions of carbon monoxide. This optimization shall be consistent with the manufacturer's specifications, and must be consistent with the NO\textsubscript{X} emission limit in Condition 22.a.

e. Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).

f. Tune-ups shall occur biennially and no later than 25 months from the previous year’s tune-up. The first biennial tune-up shall occur no later than 25 months after initial startup of the equipment.

24. **Emergency Generator Engine**

For the emergency generator engine, unit D2, the Permittee shall install and operate an engine certified to the emission standards in 40 CFR 60 Subpart III for emergency engines, for all pollutants, for the same model year and maximum engine power. In addition, for unit D2, the following requirements and provisions shall apply:

a. The engine shall comply with the emissions standards to which the engine is certified for the life of the engine.

b. Except during an emergency, operation of unit D2 shall be limited to maintenance and testing purposes. Operation for maintenance and testing purposes shall not exceed 30 minutes per day and 26 hours in a 12-month rolling period;

c. An emergency is defined as providing electrical power for critical networks or equipment when electric power from the local utility (or normal power source) is interrupted;

d. The engine shall be equipped with a non-resettable hour meter;

e. The engine shall be model year 2011 or later;

f. The engine shall burn only nonroad diesel fuel; and

g. The engine shall not operate for maintenance and testing purposes during periods of startup or shutdown of GEN1 or GEN2.

25. **Emergency Fire Pump Engine**

For the emergency fire pump engine, unit D3, the Permittee shall install and operate an engine certified to the emission standards in 40 CFR 60 Subpart III for emergency fire pump engines, for all pollutants, for the same model year and maximum engine power. In addition, for unit D3, the following requirements and provisions shall apply:

a. The engine shall comply with the emissions standards to which the engine is certified for the life of the engine.

b. Except during an emergency, operation of unit D3 shall be limited to maintenance and testing purposes, including as required for fire safety testing. Operation for maintenance and testing purposes shall not exceed 60 minutes per day or 52 hours in a 12-month rolling period;

c. An emergency is defined as providing mechanical work to pump water in the case of fire;

d. The engine shall be equipped with a non-resettable hour meter;

e. The engine shall be model year 2011 or later;

f. The engine shall burn only nonroad diesel fuel; and

g. The engine shall not operate for maintenance and testing purposes during periods of startup or shutdown of GEN1 or GEN2.

26. **SF\textsubscript{6} Circuit Breakers**

a. The circuit breakers (CB) shall be enclosed-pressure SF\textsubscript{6} circuit breakers.

b. Emissions from the circuit breakers (CB) shall not exceed an annual leakage rate of 0.5% by weight (calendar year basis).

c. The circuit breakers (CB) shall be equipped with a 10% by weight leak detection system.

27. **Fugitive Methane Equipment Leaks**
The Permittee shall design and fully implement a leak detection and repair (LDAR) program to minimize fugitive methane leaks from natural gas piping and equipment, including from valves, flanges and compressors. At a minimum, the LDAR program shall comply with the following requirements:

a. Equipment in acoustical enclosures: Potential leaks from the acoustical enclosures housing the gas compression equipment and CTGs shall be monitored continuously by gas detection equipment, to detect any natural gas leaks, and, if a leak is detected, to activate an alarm and immediately isolate the natural gas supply external to the enclosures until the leak is repaired. This continuous monitoring equipment shall be installed, operated, and maintained consistent with manufacturer’s recommendations, and undergo quality control/quality assurance checks at least annually.

b. For natural gas piping and other natural gas equipment: All piping shall be installed in accordance with Industry Codes and Standards (ASME B31.1 – Power Piping) and pressure tested after installation and prior to initial startup. In accordance with plant operating procedures, plant technicians will periodically inspect all piping, flanged connections, valves, and other natural gas equipment using hand held gas leak detection equipment. Such inspections shall occur at least each calendar quarter. All leaks will be repaired as soon as possible, and no later than 15 calendar days after discovery. A leak shall be defined as 10,000 ppmv of methane/natural gas. The methane/natural gas analyzer shall be operated and maintained consistent with manufacturer’s recommendations, and undergo quality control/quality assurance checks at least annually.

Section 3: Monitoring and Testing Requirements

28. Requirement for Continuous Emission Monitoring Systems (CEMS) for GEN1 and GEN2

The Permittee shall install, calibrate, maintain, and operate a CEMS each for GEN1 and GEN2 that measures stack gas NOX, CO, and either CO2 or O2 concentrations in ppmv. The concentrations of NOX and CO shall be corrected to 15% O2 on a dry basis. By no later than the end of the shakedown period, as defined in Condition 13, or upon the commencement of commercial operations (as defined in 40 CFR 72.2), whichever comes first, each CEMS for GEN1 and GEN2 shall be installed, certified, quality-assured and operated in accordance with Conditions 29 through 34, and as follows:

a. Each CEMS shall meet the requirements of 40 CFR 60.13;
b. Each CEMS shall be operated and data recorded during all periods of operation of GEN1 and GEN2 including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments;
c. Each CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 1-minute clock-hour period; and
d. The initial certification of the CEMS may either be conducted separately or as part of the initial performance test of each emission unit. The CEMS must undergo and pass initial performance specification testing on or before the date of the initial performance test.

29. NOX CEMS per Part 75

If the Permittee has installed a NOX CEMS to meet the requirements of 40 CFR part 75 and meets the ongoing requirements of 40 CFR part 75, that CEMS may be used to meet the requirements of Condition 28, except that the owner or operator shall also meet the requirements of Conditions 48 and 52. Data reported to meet the requirements of Condition 52 shall not include data substituted using the missing data procedures in subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

30. Continuous Flow Monitoring System

a. The Permittee shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of 40 CFR part 60, appendix B and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of 40 CFR part 60, appendix F, and record the output of the system, for measuring the volumetric flow rate of exhaust gases
discharged to the atmosphere. If the Permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the pitot tube or pitot tube assembly must be calibrated, and the 0.84 default Type-S pitot tube coefficient specified in Method 2 shall not be used; or

b. Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20(c) and appendix A to 40 CFR part 75, and continuing to meet the applicable quality control and quality assurance requirements of 40 CFR 75.21 and appendix B to 40 CFR part 75, may be used. Flow rate data reported to meet the requirements of Conditions 48 and 52 shall not include substitute data values derived from the missing data procedures in subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75. If the Permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the pitot tube or pitot tube assembly must be calibrated, and the 0.84 default Type-S pitot tube coefficient specified in Method 2 shall not be used.

31. Procedures for NO\textsubscript{X} CEMS

Each NO\textsubscript{X} CEMS shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to 40 CFR part 60 or according to the procedures in appendices A and B to 40 CFR part 75, as applicable. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to 40 CFR part 60, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to 40 CFR part 60, shall be submitted with each compliance report required under Condition 52.

a. Alternatively, for span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to 40 CFR part 75, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to 40 CFR part 60. If this option is selected: the frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to 40 CFR part 75 shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to 40 CFR part 75 shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to 40 CFR part 60; and the grace period provisions in section 2.2.4 of appendix B to 40 CFR part 75 shall apply. For the purposes of data validation, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to 40 CFR part 60 shall be performed for NO\textsubscript{X} span values less than or equal to 30 ppm.

b. Alternatively, RATAs may be performed in accordance with section 2.3 of appendix B to 40 CFR part 75 instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to 40 CFR part 60. If this option is selected: the frequency of each RATA shall be as specified in section 2.3.1 of appendix B to 40 CFR part 75; the applicable relative accuracy specifications shown in Figure 2 in appendix B to 40 CFR part 75 shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to 40 CFR part 75 shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to 40 CFR part 60; and the grace period provisions in section 2.3.3 of appendix B to 40 CFR part 75 shall apply. For the purposes of data validation, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to 40 CFR part 60 shall be met.

32. CO\textsubscript{2} Emissions Monitoring

The Permittee must determine the hourly CO\textsubscript{2} mass emissions in tons from units GEN1 and GEN2 as specified below:

a. The Permittee must, install, certify, operate, maintain, and calibrate a CO\textsubscript{2} CEMS to directly measure and record hourly average CO\textsubscript{2} concentrations in the affected EGU exhaust gases emitted to the atmosphere. As an alternative to direct measurement of CO\textsubscript{2} concentration, data from a certified oxygen (O\textsubscript{2}) monitor to calculate hourly average CO\textsubscript{2} concentrations may be used, in accordance with 40 CFR 75.10(a)(3)(iii). If CO\textsubscript{2} concentration is measured on a dry basis, the Permittee must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR part 75. Alternatively, an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) may be used.
b. For each continuous monitoring system that is used to determine the CO₂ mass emissions, the Permittee must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

c. The Permittee must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO₂ mass emissions rate from units GEN1 and GEN2, and must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

d. The permittee must select an appropriate reference method to set up (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If the Permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the pitot tube or pitot tube assembly must be calibrated, and the 0.84 default Type-S pitot tube coefficient specified in Method 2 shall not be used.

e. The hourly CO₂ ton/hr values and CTG operating times used to calculate CO₂ mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). These data must be used to calculate the hourly CO₂ mass emissions. Hourly ton/hr data shall be converted to lb/hr (by multiplying by 2000).

f. The Permittee must apportion the combined hourly net output from the STG to the individual CTG (GEN1 or GEN2) according to the fraction of the total heat input contributed by each CTG, including its associated duct burner.

33. Procedures for CO CEMS

Each CO CEMS must be installed, certified, maintained, and operated as follows:

a. The CEMS shall be operated according to Performance Specification 4A in appendix B of 40 CFR part 60;

b. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to 40 CFR part 60, and a DAR, prepared according to section 7 of Procedure 1 in appendix F to 40 CFR part 60, shall be submitted with each compliance report required under Condition 52;

c. During each relative accuracy test run of the CEMS required by Performance Specification 4 in appendix B of 40 CFR part 60, CO and O₂ (or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the following tests:
   i. For CO, EPA Reference Method 10, 10A, or 10B shall be used; and
   ii. For O₂ or CO₂, EPA Reference Method 3, 3A, or 3B, or ASME PTC-19-10-1981—part 10 (incorporated by reference, see 40 CFR 60.17 of subpart A of 40 CFR part 60), as applicable, shall be used.

34. Monitoring Plans for CEMS and Continuous Flow

At least 90 days before commencing certification testing of the monitoring systems, the Permittee shall prepare and submit to the EPA a unit-specific monitoring plan for each monitoring system for GEN1 and GEN2. The plan must be consistent with the monitoring requirements specified for GEN1 and GEN2 in Section 3 of this permit, and otherwise consistent will all other applicable requirements of this permit, including the applicable emission limits and standards in Section 2 of this permit. The Permittee shall comply with the requirements in the plan. The plan shall be updated and resubmitted as needed or upon request by the EPA. The plan must address the following requirements:

a. Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

c. Performance evaluation procedures and acceptance criteria (e.g., calibrations, RATAs);

d. Ongoing operation and maintenance procedures in accordance with the general requirements of 40 CFR 60.13(d) or 40 CFR part 75 (as applicable);

e. Ongoing data quality assurance procedures in accordance with the general requirements of 40 CFR 60.13 or 40 CFR part 75 (as applicable); and

f. Ongoing recordkeeping and reporting procedures in accordance with the requirements of this permit.
35. **SCR Monitoring**

Prior to the date of initial startup of units GEN1 and GEN2, the Permittee shall install, and thereafter maintain and operate, continuous monitoring and recording systems according to 40 CFR 60.13 to measure and record the following operational parameters:

1. The ammonia injection rate of the ammonia injection system of each SCR system; and
2. Exhaust gas temperature at the inlet to the SCR reactor.

36. **Electrical Output Monitoring**

For each CTG (GEN1 and GEN2) and its associated STG, the Permittee shall install, calibrate, maintain, and operate a wattmeter to measure net energy output in MWh on a continuous basis; and record the output of the monitor. Gross energy output, mechanical output and useful thermal output shall have the same meaning as in 40 CFR 60.5580. These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20.

37. **Calculating Compliance with CO₂ Standard for the CTGs**

The Permittee shall calculate the 12-month rolling average of pounds of CO₂ per MWh(net) as follows:

a. Each monthly compliance period shall include only “valid operating hours” in the compliance period, i.e., operating hours for which:
   
i. “Valid data” (as defined in §60.5580) are obtained for all of the parameters used to determine the hourly CO₂ mass emissions (pounds); and
   
ii. The corresponding hourly net energy output value is also valid data (For hours with no useful output, zero is considered to be a valid value).

b. The Permittee must exclude operating hours in which:
   
i. The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO₂ mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input; or
   
ii. An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO₂ mass emissions or, if applicable, to determine the hourly heat input; or
   
iii. The total net energy output (Pₙₑᵗ) is unavailable.

c. For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in Condition 37.a.

d. The Permittee must calculate the total CO₂ mass emissions by summing the valid hourly CO₂ mass emissions values for all of the valid operating hours in the compliance period.

e. For each valid operating hour of the compliance period that is used to calculate the total CO₂ mass emissions, the Permittee must determine Pₙₑᵗ (the corresponding hourly net energy output in MWh) as follows:
   
i. For an operating hour in which a valid CO₂ mass emissions value is determined, if there is no net electrical output, but there is mechanical or useful thermal output, the Permittee must still determine net energy output for that hour.
   
ii. For an operating hour in which a valid CO₂ mass emissions value is determined, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, the Permittee must use that hour in the compliance determination.
   
iii. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.
   
iv. Pₙₑᵗ is determined by summing the electrical and mechanical energy output of the steam turbine, CTG, and any integrated auxiliary equipment, and subtracting any electric energy used for any auxiliary loads.
38. On an hourly basis for each duct burner, units DB1 and DB2, the Permittee shall measure and record, in accordance with 40 CFR 60.13, (1) the actual heat input and (2) the heat input corrected to ISO standard day conditions (288 degrees Kelvin, 60 percent relative humidity, and 101.3 kPa pressure).

39. The Permittee shall monitor, for GEN1 and GEN2 (including operation of units DB1 and DB2), the pounds of CO\textsubscript{2} per heat input (lb CO\textsubscript{2}/MMBtu) corrected to ISO standard day conditions on (1) an hourly basis and (2) a 30-day rolling average basis. The 30-day rolling average shall be based on the average hourly lb/MMBtu recordings.

40. Performance Tests Protocols
The Permittee shall submit a performance test protocol for all performance tests, including for CEMS testing and RATAs, to the EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol and any changes required by the EPA.

41. Performance Tests
a. The Permittee shall conduct performance tests (as described in 40 CFR 60.8) as follows:
   i. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, the Permittee shall conduct performance tests for NO\textsubscript{x}, CO, CO\textsubscript{2}, PM, PM\textsubscript{10}, and PM\textsubscript{2.5} emissions from each gas turbine (Units GEN1/DB1 and GEN2/DB2). Units GEN1/DB1 and GEN2/DB2 shall also be performance tested annually thereafter (within 30 days before or after the previous performance test anniversary); and
   ii. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, the Permittee shall conduct performance tests for NO\textsubscript{x}, CO, PM, PM\textsubscript{10}, and PM\textsubscript{2.5} emissions from the 110 MMBtu/hr auxiliary boiler (D1). Unit D1 shall also be performance tested at least every five years thereafter (within 30 days before or after the previous performance test anniversary).

b. For each engine (D2 and D3), the Permittee shall conduct performance tests to demonstrate compliance with the standards in Conditions 24 and 25 (according to 40 CFR 60.8 and 40 CFR part 60, subpart IIII) every 5,000 hours of operation. The performance test shall be conducted within 60 days of reaching each 5,000-hour interval.

c. Performance tests shall be conducted in accordance with the test methods set forth in 40 CFR 60.8 and 40 CFR Part 60 Appendix A, as modified below. In lieu of the specified test methods, equivalent methods may be used with prior written approval from the EPA. Specifically, the Permittee shall use:
   i. EPA Method 7E for NO\textsubscript{x} emissions;
   ii. EPA Method 10 for CO emissions;
   iii. EPA Method B for CO\textsubscript{2} emissions;
   iv. EPA Methods 5 and 202, or Methods 201A and 202, for filterable and condensable PM, PM\textsubscript{10}, and PM\textsubscript{2.5}, respectively, collecting a minimum of 120 dry standard cubic feet per test run; and
   v. The provisions of 40 CFR 60.8(f).

d. In meeting the requirements in Conditions 41.a, the Permittee may conduct the performance testing during RATA testing of the applicable CEMS.

e. In limited circumstances, upon written request and with adequate justification from the Permittee, the EPA may waive a specific annual test and/or allow for testing to be done at less than maximum operating capacity. Such justification must demonstrate to the EPA’s satisfaction that it would be impractical to conduct the required test at the specified interval or to operate at maximum operating capacity during testing, as applicable. Any waiver or allowance granted by the EPA shall be approved in writing and the Permittee shall adhere to any specifications or requirements concerning such waiver or allowance that the EPA imposes therein.

f. For performance test purposes, sampling ports, platforms, and access shall be provided on the emission unit exhaust system in accordance with the requirements of 40 CFR 60.8(e).

g. The Permittee shall furnish the EPA with a written report of the results of performance tests within 60 days of
42. For each CTG, GEN1 and GEN2, the Permittee shall install, calibrate, maintain and operate a non-resettable totalizing volumetric fuel flow meter for each fuel line. The flow meter shall be maintained according to requirements in 40 CFR 60.13.

43. For each CTG, GEN1 and GEN2, the Permittee shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor. The monitors shall be operated and maintained according to the requirements in 40 CFR 60.13.

44. **Fuel Testing**
   The Permittee shall take monthly samples of the natural gas combusted at the Source. The samples shall be analyzed for sulfur content using an ASTM method. The sulfur content test results shall be retained onsite and taken to ensure compliance with Condition 17.

45. **Monitoring for Auxiliary Equipment**
   a. The Permittee shall install and maintain a non-resettable totalizing volumetric flow meter in each fuel line for the auxiliary boiler, unit D1.
   b. The Permittee shall install and maintain a non-resettable elapsed time meter for each of the engines – units D2 and D3.
   c. The Permittee shall install and maintain a leak detection system on the circuit breakers (CB) that signals an alarm in the Source’s control room in the event that any circuit breaker loses more than 10% of its dielectric fluid. The owner/operator shall promptly (1) respond to any such alarm, (2) investigate the circuit breaker involved, and (3) fix any leak-tightness problems that caused the alarm.

**Section 4: Recordkeeping Requirements**

46. All records required by this permit shall be retained for not less than five years following the date of the relevant measurements, maintenance reports, and/or records.

47. The Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the Source in a permanent form suitable for inspection including, but not limited to, the following:
   a. All records or reports pertaining to adjustments and/or maintenance performed on any system or device at the Source;
   b. All records relating to performance tests and monitoring for each emissions unit;
   c. All reports and notifications submitted;
   d. Records demonstrating compliance with each emission limit in Section 2, including any calculations or supporting information used to determine compliance;
   e. Records of maintenance performance on any system or device at the Source, including a maintenance log as described in Condition 50;
   f. Date, time, and duration of each startup and shutdown event for units GEN1 and GEN2, including whether the startup was a cold, warm, or hot startup.
   g. Emissions of NOx and CO associated with each startup and shutdown event as measured by the CEMS;
   h. Identification of the times when the pollutant concentration exceeded full span of a CEMS;
   i. For any periods for which NOx, CO, or CO2 emissions data are not available, the Permittee shall submit to the EPA a signed statement indicating whether any changes were made in operation of the emission control system during the period of data unavailability; operations of the control system and affected emission unit(s) during
periods of data unavailability are to be compared with operation of the control system and affected emission
unit(s) before and following the period of data unavailability;
j. Description of any modifications to CEMS which could affect the ability of the CEMS to comply with the
applicable performance specification;
k. Results of monthly natural gas fuel testing;
l. Monthly hours of operation for the duct burners and auxiliary boiler (units DB1, DB2, and D1), including the
resulting rolling 12-month total;
m. Monthly hours of operation for the emergency engines (units D2 and D3) including the resulting calendar year
total;
n. Documentation of engine certification for each engine (units D2 and D3);
o. For each diesel fuel delivery, documents demonstrating that nonroad diesel fuel was purchased;
p. Pounds of dielectric fluid added to the circuit breakers each month, and the current total annual leak rate, based
on the assumption that all added dielectric fluid replaced fluid that was leaked, for purposes of complying with
Condition 26;
q. Documentation of installation, testing, monitoring, maintenance, and repairs associated with the LDAR program
accordance with the requirements of Condition 27; and
r. All other information required by this permit.

48. For each continuous monitoring system, the Permittee shall maintain records of the occurrence and duration of any
startup, shutdown, shakedown, or malfunction, performance testing, evaluations, calibrations, checks, adjustments,
maintenance, duration of any periods during which a continuous monitoring system or monitoring device is
inoperative, and corresponding emission measurements. A period of monitor down-time shall be any unit operating
clock hour in which sufficient data are not obtained by the CEMS to validate the hour for NOx, CO, CO2, or O2, while
the CEMS is also meeting the requirements of Condition 28.a.

49. For each biennial tune-up of the auxiliary boiler, unit D1, the Permittee shall maintain onsite a report containing the
information below:
   a. The concentrations of CO in the effluent stream of the boiler in parts per million, by volume, and oxygen in
      volume percent, measured before and after the tune-up of the boiler;
   b. A description of any corrective actions taken as a part of the tune-up of the boiler; and
   c. The amount of fuel used over the 12 months prior to the biennial tune-up of the boiler.

50. The Permittee shall maintain a log describing the maintenance and repair activities for all emission units and control
equipment, including the following information:
   a. Date of activity;
   b. Description of activity;
   c. For scheduled maintenance, the elapsed time, hours of operation, or other applicable measure since the activity
      was last performed;
   d. For scheduled maintenance, the elapsed time, hours of operation, or other applicable measure until the activity
      should next be performed; and
   e. For each CTG (GEN1 and GEN2), the activities associated with a maintenance plan that ensures regular
      maintenance intervals, consistent with manufacturer’s recommendations, for minimizing recoverable losses in
      turbine efficiency.

Section 5: Reporting Requirements

51. The Permittee shall submit a report of all excess emissions and any other noncompliance with the conditions and
requirements of this permit to the EPA for each six-month reporting period from January 1 to June 30 and from July
1 to December 31, except when more frequent reporting is required by an applicable subpart, or when the EPA, on a
case-by-case basis, determines and informs the Permittee that more frequent reporting is necessary to accurately assess the compliance status of the Source, in which case the Permittee shall comply with the more frequent reporting requirement specified by the EPA. Each report shall be postmarked by the 30th day following the end of each six-month reporting period and shall include, but not be limited to, the following:

a. Time intervals, data, and magnitude of the excess emissions;

b. Nature and cause of the excess emissions (if known);

c. Corrective actions taken and preventive measures adopted;

d. Applicable time and date of each period during which the CEMS was inoperative (monitor down-time), except for zero and span checks, and the nature of CEMS repairs or adjustments;

e. If applicable, a statement in the report specifying that no excess emissions occurred and/or that the monitoring equipment has not been inoperative, repaired, or adjusted;

f. Any failure to conduct any required source testing, monitoring, or other compliance activities;

g. Any violation of limitations on operation, including but not limited to restrictions on hours of operation.

Excess emissions shall be defined as any period in which an emissions unit (listed in the Equipment List above) exceeds any emission limits set forth in Section 2 of this permit. Excess emissions indicated by the CEMS, performance testing, or compliance monitoring shall be considered violations of the applicable emission limit for the purposes of this permit.

52. Records for CEMS
For each report submitted to the EPA according to Condition 51, the Permittee shall submit a signed statement indicating whether:

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified in this permit;

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this permit and is representative of plant performance;

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable; and

d. Whether compliance with the applicable emission limit has or has not been achieved during the reporting period.

53. Performance Tests Reports
The Permittee shall submit a test report, including for RATAs conducted for CEMS, to the EPA within 60 days after the completion of any required performance test. At a minimum, the test report shall include:

a. A description of the emissions unit and sampling location(s);

b. The time and date of each test;

c. A summary of test results, reported in units consistent with the applicable standard;

d. A description of the test methods and quality assurance procedures used;

e. A summary of any deviations from the proposed test plan and justification for why the deviation(s) was necessary;

f. The amount of fuel burned, raw material consumed, and/or product produced during each test run;

g. Operating parameters of the emission unit(s) being tested and applicable control equipment during each test run;

h. Sample calculations of equations used to determine test results in the appropriate units; and

i. The name of the company or entity performing the analysis.

54. Malfunction Report
a. The Permittee shall notify the EPA by email within two (2) working days following the discovery of any failure of equipment listed in this permit (see Equipment List above), or failure of a process listed in this permit to operate
in a normal manner, which results in an increase in emissions above any allowable emission limit stated in Section 2 of this permit.

b. The Permittee shall provide an additional notification to the EPA within 15 days of any such failure described in Condition 54.a. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section 2, and the methods utilized to mitigate emissions and restore normal operations.

c. Compliance with the malfunction notification provision in Condition 54.b shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.
Attachment A: Abbreviations and Acronyms

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>AQMD</td>
<td>Air Quality Management District</td>
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</tr>
<tr>
<td>ASTM</td>
<td>American Society for Testing and Materials</td>
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</tr>
<tr>
<td>BACT</td>
<td>best available control technology</td>
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</tr>
<tr>
<td>Btu</td>
<td>British thermal unit</td>
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</tr>
<tr>
<td>CAA</td>
<td>Clean Air Act</td>
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</tr>
<tr>
<td>CD</td>
<td>calibration drift</td>
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<tr>
<td>CEMS</td>
<td>Continuous Emissions Monitoring System</td>
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</tr>
<tr>
<td>CFR</td>
<td>Code of Federal Regulations</td>
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<tr>
<td>CGA</td>
<td>cylinder gas audits</td>
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<tr>
<td>CO</td>
<td>carbon monoxide</td>
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</tr>
<tr>
<td>CO₂</td>
<td>carbon dioxide</td>
<td></td>
</tr>
<tr>
<td>CTG</td>
<td>combustion turbine generator</td>
<td></td>
</tr>
<tr>
<td>DAR</td>
<td>data assessment report</td>
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</tr>
<tr>
<td>District</td>
<td>Antelope Valley Air Quality Management District</td>
<td></td>
</tr>
<tr>
<td>DLN</td>
<td>dry low NO&lt;sub&gt; X &lt;/sub&gt;</td>
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</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency, Region 9</td>
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<tr>
<td>g</td>
<td>grams</td>
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<tr>
<td>GHG</td>
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<tr>
<td>HHV</td>
<td>higher heating value</td>
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<tr>
<td>HRSG</td>
<td>heat recovery steam generator</td>
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<td>hp</td>
<td>horsepower</td>
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<tr>
<td>hr</td>
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<tr>
<td>kPa</td>
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<tr>
<td>kW</td>
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<tr>
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</tr>
<tr>
<td>lbs</td>
<td>pounds</td>
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<tr>
<td>MMBtu</td>
<td>million British thermal units</td>
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<tr>
<td>MW</td>
<td>megawatt</td>
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<tr>
<td>NAAQS</td>
<td>National Ambient Air Quality Standards</td>
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<td>NO₂</td>
<td>nitrogen dioxide</td>
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<td>NO&lt;sub&gt; X &lt;/sub&gt;</td>
<td>oxides of nitrogen</td>
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<td>NSPS</td>
<td>New Source Performance Standards</td>
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<tr>
<td>O₂</td>
<td>oxygen</td>
<td></td>
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<tr>
<td>PEP</td>
<td>Palmdale Energy Project</td>
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<tr>
<td>PM</td>
<td>total particulate matter</td>
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<tr>
<td>PM&lt;sub&gt;2.5&lt;/sub&gt;</td>
<td>particulate matter with aerodynamic</td>
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<td>particulate matter with aerodynamic</td>
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</tr>
<tr>
<td>ppm</td>
<td>parts per million</td>
<td></td>
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<tr>
<td>ppmvd</td>
<td>parts per million by volume, dry basis</td>
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<tr>
<td>ppmv</td>
<td>parts per million by volume</td>
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<tr>
<td>PSD</td>
<td>Prevention of Significant Deterioration</td>
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<tr>
<td>PUC</td>
<td>Public Utilities Commission</td>
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<tr>
<td>RATA</td>
<td>relative accuracy test audit</td>
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<tr>
<td>scf</td>
<td>standard cubic feet</td>
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<tr>
<td>SCR</td>
<td>selective catalytic reduction</td>
<td></td>
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<tr>
<td>SF&lt;sub&gt;6&lt;/sub&gt;</td>
<td>sulfur hexafluoride</td>
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<tr>
<td>STG</td>
<td>steam turbine generator</td>
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</tr>
<tr>
<td>tpy</td>
<td>tons per year</td>
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<tr>
<td>yr</td>
<td>Year</td>
<td></td>
</tr>
<tr>
<td>µm</td>
<td>micrometer</td>
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</table>
Exhibit 3
Mr. Mark Mirabito  
Chief Operating Officer  
NTE Connecticut, LLC  
24 Cathedral Place, Suite 300  
Saint Augustine, FL 32084

Dear Mr. Mirabito:

Enclosed are copies of your new permits to construct and operate a 550 MW Combined Cycle Power Plant consisting of one Siemens Model SGT6-8000H combustion turbine with duct firing and one emergency engine at 180/189 Lake Road, Killingly, CT.

This letter does not relieve you of the responsibility to comply with the requirements of other appropriate Federal, State, and municipal agencies. These permits are not transferable from one permittee to another (without prior written approval), from one location to another, or from one piece of equipment to another. The permits must be made available at the site of operation throughout the period that such permit is in effect.

Permit renewal applications must be filed at least one hundred twenty (120) days prior to the permit expiration date, if applicable. Pursuant to Section 22a-174-3a of the Regulations of Connecticut State Agencies, NTE Connecticut, LLC must apply for a permit modification/revision in writing if it plans any physical change, change in method of operation, or addition to this source which constitutes a modification or revision pursuant to Section 22a-174-1 and 22a-174-2a, respectively. Any such changes should first be discussed with Mr. James Grillo of the Bureau of Air Management, by calling (860) 424-4152. Such changes shall not commence prior to the issuance of a permit modification.

Sincerely,

Gary S. Rose  
Director  
Engineering & Enforcement Division  
Bureau of Air Management

GSR:JAG:jad  
Enclosure
BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

<table>
<thead>
<tr>
<th>Owner/Operator</th>
<th>NTE Connecticut, LLC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Address</td>
<td>24 Cathedral Place, Suite 300 Saint Augustine, FL 32084</td>
</tr>
<tr>
<td>Equipment Location</td>
<td>180/189 Lake Road, Killingly, CT 06241</td>
</tr>
<tr>
<td>Equipment Description</td>
<td>Siemens SGT6-8000H Combustion Turbine with DLN combustors, Duct Burners and Heat Recovery Steam Generator</td>
</tr>
<tr>
<td>Collateral Conditions</td>
<td>This permit contains collateral conditions for one 84 MMBtu/hr natural gas fired boiler, one 305 bhp emergency fire pump engine, one 5MMBtu/hr natural gas heater, and one 1,380 kW emergency generator engine (Permit No. 089-0108)</td>
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<td>Town-Permit Numbers</td>
<td>089-0107</td>
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<tr>
<td>Premises Number</td>
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<tr>
<td>Stack Number</td>
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</tr>
<tr>
<td>Permit Issue Date</td>
<td>JUN 3 0 2017</td>
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<tr>
<td>Expiration Date</td>
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</table>

Robert J. Klee
Commissioner

6/30/2017

ORIGINAL
This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

NTE Connecticut, LLC operates a power generation facility consisting of one Siemens SGT6-8000H combustion turbine with dry low-NOx (DLN) combustors with a nominal gross electrical output of 550 MW in Killingly, CT. The turbine is a dual fuel fired combined cycle unit, with a separate heat recovery steam generator (HRSG) that includes natural gas supplementary firing (duct burners) to power a single steam turbine generator. Oil firing for the turbine is limited to ultra-low sulfur distillate (ULSD) No. 2 fuel oil as allowed in Part II.A.1.d of this permit. Pollution control equipment will include selective catalytic reduction (SCR), oxidation catalyst, and water injection (ULSD firing only) to control NOx, CO and VOC emissions. The turbine, duct burner, and HRSG are considered the combustion turbine generator (CTG) and designated as Emissions Unit 1 (EU-1) for this permit.

There is one 1,380 kW ULSD fired emergency generator engine that operates under permit number 089-0108.

The ancillary equipment that do not require permits includes: one 84 MMBtu/hr natural gas fired auxiliary boiler with flue-gas-recirculation (FGR) to control NOx emissions; one 305 bhp emergency ULSD fired fire pump engine, and one 5 MMBtu/hr natural gas heater. The boiler and gas heater will be able to operate for approximately 4,600 and 4,000, hours respectively, per year at maximum rated capacity with the allowable fuel limits. The emergency generator engine and emergency fire pump engine can only fire ULSD and are each limited to 300 hr/yr and not more than 500 hr/yr combined. Collateral conditions for this equipment are included in Part VI of this permit.

The CTG will also be fed by a ULSD oil tank with a capacity of one million gallons. The emergency engines will have self-contained oil tanks. There will be a 12,000 gallon storage tank for the 19% aqueous ammonia (NH₃) used in the NOx control system.

B. Equipment Design Specifications

1. Turbine
   The design gross heat input is 2,969 MMBtu/hr while firing natural gas and 2,639 MMBtu/hr while firing ULSD. These heat inputs are based on an ambient temperature of 59°F and result in firing rates of 2,888,132 scf of natural gas (HHV 1028 Btu/scf) and 19,058 gallons of ULSD (HHV 138,000 Btu/gal) per hour. Heat input will vary by approximately ±10% over the typical range of expected ambient temperatures, with higher heat input occurring at lower ambient temperatures.

2. Duct Burner
   The design gross heat input to the duct burner is 946 MMBtu/hr while firing natural gas. The heat input is based on an assumed HHV of 1028 Btu/scf and results in a firing rate of 920,233 scf/hr.
C. Stack Parameters

1. Minimum Stack Height (ft): 150 (above base elevation)

2. Minimum Exhaust Gas Flow Rate at maximum operating load, CTG only (acfm): 1,282,886 (gas); 1,349,732 (ULSD)

3. Minimum Stack Exit Temperature at 100% load (°F): 175

4. Minimum Distance from Stack to Property Line (ft): 425

D. Definitions

1. "Steady-State" operation shall be defined as all periods other than transient operation.

2. "Transient" operation shall be all modes of operation at Loads less than 40%, including periods of startup, shutdown, fuel switching and equipment cleaning.

3. "Load" shall be defined as the net electrical output of the CTG.

4. "Shakedown" shall be defined as CTG operations including, but not limited to, the first firing of the unit, proof of interlocks, steam blowing, chemical cleaning, initial turbine roll and ending after the equipment vendor service representative conducts operational and contractual testing and tuning of the turbine to meet warranted emission rates on site. The Shakedown period shall not extend beyond the required date for the initial performance test.

5. "Btu" shall be defined as British Thermal Units and "MMBtu" as one million Btu, both on a higher heating value (HHV) basis.

PART II. OPERATIONAL CONDITIONS and REQUIREMENTS

A. Equipment

1. CTG
   a. Allowable Fuel Types: Natural Gas (primary); Ultra-Low Sulfur Distillate (ULSD)
   b. Maximum Heat Input over any Consecutive 12 Month Period: 2.60 x 10^7 MMBtu (gas);
      1.89 x 10^6 MMBtu (ULSD)
   c. Maximum ULSD Sulfur Content (% by weight, dry basis): 0.0015
   d. Firing of ULSD is allowed only in the following scenarios:
      i. ISO-NE declares an Energy Emergency as defined in ISO New England's Operating
         Procedure No. 21 and requests the firing of ULSD;
      ii. ISO-NE required audits of capacity;
      iii. The natural gas supply is curtailed by an entity through which gas supply and/or
           transportation is contracted;
      iv. Any equipment (whether on- or off-site) required to allow the CTG to operate on
          natural gas has failed, including a physical blockage of the supply pipeline. In the
          event of failure of onsite equipment, the Permittee shall document that this equipment
          has been maintained in accordance with manufacturer's recommendations and that the
          failed equipment was repaired or replaced and the CTG was returned to natural gas
          firing as soon as practicable;
      v. During the Shakedown period when the CTG is required to operate on ULSD pursuant
         to the manufacturer's written instructions;
vi. For emission testing purposes, as specified in the Part V of this permit or as required by DEEP, USEPA or other regulatory order requiring emissions testing during ULSD firing;

or

vii. During routine maintenance and readiness testing, if any equipment requires ULSD operation.

e. The Permittee shall not operate the duct burner while firing ULSD in the CTG.

f. No period of Transient operation shall exceed 60 consecutive minutes.

2. Duct Burner
   a. Allowable Fuel: Natural Gas
   b. Maximum Heat Input over any Consecutive 12 Month Period: 8.29 x 10^6 MMBtu

3. The Permittee shall comply with all applicable sections of the following New Source Performance Standards at all times.

   Title 40 CFR Part 60 Subparts KKKK, TTTT and A


B. The Permittee shall operate this equipment, including the SCR, oxidation catalyst, and water injection in a manner to comply with the emissions limits in Part III of this permit.

C. The Permittee shall operate and maintain this equipment, 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 and shutdown.

D. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.

E. The Permittee shall minimize emissions during periods of startup and shutdown to the extent practicable, and during startup shall start the ammonia injection as soon as the SCR vendor's recommended minimum catalyst temperature is reached. The Permittee shall incorporate the SCR vendor's recommended minimum catalyst temperature into this permit by modification pursuant to RCSA Section 22a-174-2a, and shall submit an application for such modification prior to or concurrently with submittal of the Permittee's application for an operating permit pursuant to RCSA Section 22a-174-33.

F. The Permittee shall not operate the auxiliary boiler (EU-2) simultaneously with the CTG for more than 500 hours in any calendar year.

G. The Permittee shall not exceed a maximum allowable heat rate at full operating load while firing natural gas, without duct firing, of 7,273 Btu/kW-hr, 12 month rolling average (HHV, net plant).

H. The Permittee shall immediately institute shutdown of the CTG in the event where emissions are in excess of a limit in Part III.A of this permit that cannot be corrected within three hours of when the emissions exceedance was identified.

I. The Permittee shall not operate CTG during startup and shutdown events for more than 500 hours per calendar year.
PART III. CTG ALLOWABLE EMISSION LIMITS

A. Steady State
   Except during the Shakedown period, the Permittee shall not cause or allow this equipment to exceed these emission limits stated herein at any time during Steady-State operation.

1. CTG Operating on Natural Gas without Duct Firing

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>ppmvd @ 15% O₂</th>
<th>lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>13.0</td>
<td></td>
<td>0.0044</td>
</tr>
<tr>
<td>PM₁₀/₂₅</td>
<td>13.0</td>
<td></td>
<td>0.0044</td>
</tr>
<tr>
<td>SO₂</td>
<td>4.5</td>
<td></td>
<td>0.0015</td>
</tr>
<tr>
<td>NOₓ</td>
<td>22.5</td>
<td>2.0</td>
<td></td>
</tr>
<tr>
<td>VOC</td>
<td>2.8</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>6.2</td>
<td>0.9</td>
<td></td>
</tr>
<tr>
<td>Lead</td>
<td>1.44E-03</td>
<td></td>
<td>4.9E-07</td>
</tr>
<tr>
<td>H₂SO₄</td>
<td>1.6</td>
<td></td>
<td>0.00053</td>
</tr>
<tr>
<td>Ammonia</td>
<td></td>
<td>2.0</td>
<td></td>
</tr>
</tbody>
</table>

2. CTG Operating on Natural Gas with Duct Firing

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>ppmvd @ 15% O₂</th>
<th>lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>19.5</td>
<td></td>
<td>0.0050</td>
</tr>
<tr>
<td>PM₁₀/₂₅</td>
<td>19.5</td>
<td></td>
<td>0.0050</td>
</tr>
<tr>
<td>SO₂</td>
<td>5.9</td>
<td></td>
<td>0.0015</td>
</tr>
<tr>
<td>NOₓ</td>
<td>29.7</td>
<td>2.0</td>
<td></td>
</tr>
<tr>
<td>VOC</td>
<td>8.3</td>
<td>1.6</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>15.4</td>
<td>1.7</td>
<td></td>
</tr>
<tr>
<td>Lead</td>
<td>1.9E-03</td>
<td></td>
<td>4.9E-07</td>
</tr>
<tr>
<td>H₂SO₄</td>
<td>2.0</td>
<td></td>
<td>0.00053</td>
</tr>
<tr>
<td>Ammonia</td>
<td></td>
<td>2.0</td>
<td></td>
</tr>
</tbody>
</table>

3. CTG Operating on ULSD

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>ppmvd @ 15% O₂</th>
<th>lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>30.0</td>
<td></td>
<td>0.0168</td>
</tr>
<tr>
<td>PM₁₀/₂₅</td>
<td>30.0</td>
<td></td>
<td>0.0168</td>
</tr>
<tr>
<td>SO₂</td>
<td>4.0</td>
<td></td>
<td>0.0015</td>
</tr>
<tr>
<td>NOₓ</td>
<td>40.9</td>
<td>4.0</td>
<td></td>
</tr>
<tr>
<td>VOC</td>
<td>7.1</td>
<td>2.0</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>11.2</td>
<td>1.8</td>
<td></td>
</tr>
<tr>
<td>Lead</td>
<td>3.0E-03</td>
<td></td>
<td>1.05E-06</td>
</tr>
<tr>
<td>H₂SO₄</td>
<td>1.5</td>
<td></td>
<td>0.00054</td>
</tr>
<tr>
<td>Ammonia</td>
<td></td>
<td>5.0</td>
<td></td>
</tr>
</tbody>
</table>
B. Transient Emissions

1. Except during the Shakedown period, the Permittee shall not cause or allow this equipment to exceed these emission limits during startup and shutdown events. No startup or shutdown event shall last longer than 60 consecutive minutes.

<table>
<thead>
<tr>
<th>Type of Event</th>
<th>Startup</th>
<th>Shutdown</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Natural Gas</td>
<td>ULSD</td>
</tr>
<tr>
<td>NO\textsubscript{x} (lb/hr)</td>
<td>142</td>
<td>193</td>
</tr>
<tr>
<td>VOC (lb/hr)</td>
<td>45</td>
<td>264</td>
</tr>
<tr>
<td>CO (lb/hr)</td>
<td>477</td>
<td>2,306</td>
</tr>
</tbody>
</table>

2. Ammonia (NH\textsubscript{3}) emissions shall not exceed 5.0ppmv at 15% O\textsubscript{2} (both fuels) during Transient operation.

C. Total Allowable Annual Emission Limits

The Permittee shall not cause or allow this equipment to exceed these emission limits stated herein at any time.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per 12 consecutive months</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>88.7</td>
</tr>
<tr>
<td>PM\textsubscript{10/2.5}</td>
<td>88.7</td>
</tr>
<tr>
<td>SO\textsubscript{2}</td>
<td>25.1</td>
</tr>
<tr>
<td>NO\textsubscript{x}</td>
<td>130.1</td>
</tr>
<tr>
<td>VOC</td>
<td>41.7</td>
</tr>
<tr>
<td>CO</td>
<td>134.6</td>
</tr>
<tr>
<td>Pb</td>
<td>0.0018</td>
</tr>
<tr>
<td>H\textsubscript{2}SO\textsubscript{4}</td>
<td>8.76</td>
</tr>
<tr>
<td>CO\textsubscript{2}</td>
<td>1,989,650</td>
</tr>
<tr>
<td>NH\textsubscript{3}</td>
<td>49.8</td>
</tr>
</tbody>
</table>

D. Greenhouse Gas Emissions

The Permittee shall not exceed an annual CO\textsubscript{2}e emissions limit of 2,014,335 tons/yr for combustion sources identified as EU-1, EU-2, EU-4, and EU-5 in this permit, along with permit number 089-0108, including SF\textsubscript{6} containing insulated electrical equipment. Compliance with this limitation shall be determined on a consecutive 12 month rolling basis.

E. Hazardous Air Pollutants (HAP)

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

F. Opacity

This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR Part 60, Appendix A, Reference Method 9.
G. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

- PM/PM$_{10}$/PM$_{2.5}$, VOC, Formaldehyde, H$_2$SO$_4$: Most recent Stack test data
- SO$_2$: Sulfur content in fuel
- NO$_x$ & CO (Steady-State): CEM data
- NO$_x$, VOC, & CO (Transient): Manufacturer’s uncontrolled emission factors
- GHG (CO$_{2e}$) Emissions:
  1. CO$_2$ emissions from the combustion CTG shall be determined by the methodology found in 40 CFR Part 75, Appendix G, Equation G-4.
  2. CO$_2$ emissions from the auxiliary boiler (EU-2), the emergency fire pump engine (EU-4), and the natural gas heater (EU-5) shall be determined using the default emissions factors found in 40 CFR Part 98, Subpart C, Table C-1.
  3. Methane (CH$_4$) and nitrous oxide (N$_2$O) for all combustion sources shall be determined using the default emissions factors found in 40 CFR Part 98 Subpart C, Table C-2.
  4. Estimated fugitive emissions of sulfur hexafluoride (SF$_6$) from the electrical circuit breakers shall be determined using mass balance.
  5. Estimated fugitive emissions of CH$_4$ from the natural gas pipeline and associated components shall be determined using default emissions factors found in 40 CFR Part 98 Subpart W, Table W-7.

H. Emissions prior to the completion of the Shakedown period shall be counted towards the annual emission limits stated herein.

I. The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall comply with the CEM requirements as set forth in RCSA Section 22a-174-4, the applicable sections of RCSA Sections 22a-174-22, 22a-174-22a and 22a-174-31; 40 CFR Part 60 Subparts KKKK and TTTT, and 40 CFR Parts 72-78, as applicable. Continuous Emissions Monitoring (CEM) is required for the following and enforced on the following basis:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Times</th>
<th>Emission Limit (ppmvd @15% O$_2$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Opacity (ULSD only)</td>
<td>six minute block</td>
<td>10%</td>
</tr>
<tr>
<td>NO$_x$</td>
<td>1 hour block</td>
<td>See Part III.A</td>
</tr>
<tr>
<td>CO</td>
<td>1 hour block</td>
<td>See Part III.A</td>
</tr>
<tr>
<td>NH$_3$</td>
<td>1 hour block</td>
<td>See Part III.A</td>
</tr>
</tbody>
</table>

2. The Permittee shall continuously monitor the following parameters:

<table>
<thead>
<tr>
<th>Operational Parameter</th>
<th>Averaging Times</th>
</tr>
</thead>
<tbody>
<tr>
<td>O$_2$</td>
<td>1 hour block</td>
</tr>
<tr>
<td>Fuel Flow</td>
<td>1 hour block</td>
</tr>
<tr>
<td>Net Electrical Output</td>
<td>Continuous</td>
</tr>
</tbody>
</table>
3. At least 60 days prior to the initial stack test specified in Part V.B, the Permittee shall submit a CEM monitoring plan to the commissioner in accordance with RCSA Section 22a-174-4(c)(3).

4. The Permittee shall use fuel flow meters, certified in accordance with 40 CFR Part 75, Appendix D to measure and record the flow rate of fuels to the CTG.

5. The Permittee shall perform inspections and maintenance of the SCR and oxidation catalysts as recommended by the manufacturer.

6. Prior to operation, the Permittee shall develop a written plan for the operation, inspection, maintenance, preventive and corrective measures for minimizing fugitive GHG emissions (CH₄ emissions from the natural gas pipeline components and SF₆ emissions from the insulated electrical equipment). At a minimum the plan shall provide for:
   a. Implementation of daily auditory/visual/olfactory inspections of the natural gas piping components supplying natural gas to the CTG;
   b. An installed leak detection system to include audible alarms to identify SF₆ leakage from the circuit breakers; and
   c. Inspection for SF₆ emissions from the insulated electrical equipment on at least a monthly basis.

B. Record Keeping

1. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption for the CTG (for each fuel). The consecutive 12 month fuel consumption shall be determined by adding (for each fuel) the current month’s fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. The Permittee shall keep records of the monthly and consecutive 12 month heat input for the CTG (for each fuel). The consecutive 12 month heat input shall be determined by adding (for each fuel) the current month’s heat input to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month. The records shall include sample calculations.

3. The Permittee shall keep records of the fuel certification for each delivery of ULSD from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the ULSD used by the equipment that includes the applicable sulfur content of the ULSD as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the ULSD supplier, type of fuel delivered, the percentage of sulfur in the ULSD, by weight, dry basis, and the method used to determine the sulfur content of such fuel.

4. The Permittee shall calculate and record the monthly and consecutive 12 month PM₂.₅, PM₁₀, PM₉.₅, SO₂, NOₓ, VOC, CO₂, H₂SO₄, NH₃, and CO₂e emissions in units of tons for the CTG.

The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month’s emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

Emissions during startup and shutdown shall be included in the monthly and consecutive 12 month calculations.
5. The Permittee shall keep records of the emissions of this CTG during the Shakedown period. Emissions during Shakedown shall be calculated using good engineering judgment and the best data and methodology available for estimating such emissions. Emissions during Shakedown shall be counted towards the annual emission limitation in Part III.C of this permit.

6. The Permittee shall keep records of the occurrence and duration of all Transient operation of the unit; any malfunction of the air pollution control equipment that causes an exceedance of any emission limitation found in Part III of this permit; or any periods during which a continuous monitoring system or monitoring device is inoperative.

Such records shall contain the following information:

a. the type of event and percent load;
b. equipment affected;
c. date of event;
d. duration of event (minutes);
e. fuel being used during event; and
f. total NOx, CO and VOC emissions emitted (lb) during the event.

7. The Permittee shall keep records of each delivery of aqueous ammonia. The records shall include:

a. the date of delivery;
b. the name of the supplier;
c. the quantity of aqueous ammonia delivered; and
d. the percentage of ammonia in solution, by weight.

8. The Permittee shall keep records of the inspection and maintenance of the SCR and oxidation catalysts. The records shall include:

a. the name of the person conducting the inspection/maintenance;
b. the date of the inspection/maintenance;
c. the results or actions taken; and

d. the date the catalyst is replaced.

9. The Permittee shall keep records of all repairs/replacement of parts and other maintenance activities for the equipment.

10. The Permittee shall keep records of the electrical output to the ISO-NE transmissions system and the heat rate for the turbine while firing natural gas (HHV, net) without duct firing, on a 12month rolling average for the plant.

11. The Permittee shall keep records of the inspection, maintenance, preventive and corrective measures for minimizing GHG emissions from the natural gas pipeline components and the SF6-containing insulated electrical equipment. The records shall include:

a. the name of the person conducting the inspection/maintenance;
b. the date the inspection/maintenance;
c. the results or actions taken;
d. the leak detection methods used;
e. the amount of SF6 added (if any) to the electrical equipment;
f. the monthly records of the audible alarms from the SF6 leak detection system; and
g. All monitoring, record keeping and reporting pursuant to the relevant provisions of 40 CFR Part 98 Subpart DD, as applicable.
12. The Permittee shall make and keep records of all occurrences of firing ULSD in the CTG. At a minimum these records shall contain the following information:
   a. the duration of ULSD firing,
   b. the reason for ULSD firing, and
   c. the heat input to the CTG while firing ULSD.

13. The Permittee shall keep a signed copy of this permit on the premises at all times, and shall make this copy available upon request of the commissioner for the duration of this permit. This copy shall also be available for public inspection during regular business hours.

14. The Permittee shall keep a copy of all notifications submitted as required by Part IV.C of this permit.

15. The Permittee shall keep records of the manufacturer written recommendations for operation and maintenance of the equipment found in this permit.

16. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall notify the commissioner in writing of all exceedances of an emissions limitation, and shall identify the cause or likely cause of such exceedance, all corrective actions and preventive measures taken with respect thereto, and the dates of such actions and measures as follows:
   a. For any hazardous air pollutant, no later than 24 hours after such exceedance was identified; and
   b. For any other regulated air pollutant, no later than ten days after such exceedance commenced.

2. The Permittee shall notify the commissioner, in writing, of the dates of commencement of construction, completion of construction, and initial startup, and the date of completion of initial shakedown period of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. STACK EMISSION TEST REQUIREMENTS

A. Stack emission testing shall be performed in accordance with the RCSA Section 22a-174-5 and the Emission Test Guidelines available on the DEEP website.

B. For the purposes of determining maximum heat input of the turbine during stack testing, the following equation may be used:

\[ MH_{fr} = Q_1 - [(T - T_1) / (T_2 - T_1)] \times (Q_1 - Q_2) \]

Where,

- \( MH_{fr} \) = Turbine maximum heat input at ambient temperature (°F)
- \( T \) = Ambient Temperature
- \( T_1 \) = Temperature Value from Table 1 that is immediately below the ambient temperature
- \( T_2 \) = Temperature Value from Table 1 that is immediately above the ambient temperature
- \( Q_1 \) = Heat Input at corresponding \( T_1 \) for corresponding fuel type
- \( Q_2 \) = Heat Input at corresponding \( T_2 \) for corresponding fuel type
Table 1

<table>
<thead>
<tr>
<th>Ambient Temperature (°F)</th>
<th>Gas Firing Heat Input (Q)</th>
<th>ULSD Heat Input (Q)</th>
</tr>
</thead>
<tbody>
<tr>
<td>-10</td>
<td>3,123</td>
<td>2,756</td>
</tr>
<tr>
<td>0</td>
<td>3,122</td>
<td>2,771</td>
</tr>
<tr>
<td>20</td>
<td>3,129</td>
<td>2,748</td>
</tr>
<tr>
<td>30</td>
<td>3,110</td>
<td>2,745</td>
</tr>
<tr>
<td>50</td>
<td>3,018</td>
<td>2,754</td>
</tr>
<tr>
<td>59</td>
<td>2,969</td>
<td>2,762</td>
</tr>
<tr>
<td>65</td>
<td>2,926</td>
<td>2,759</td>
</tr>
<tr>
<td>90</td>
<td>2,733</td>
<td>2,730</td>
</tr>
<tr>
<td>100</td>
<td>2,615</td>
<td>2,689</td>
</tr>
</tbody>
</table>

C. The duct burner shall be required to meet a minimum heat input value of 740 MMBtu/hr for all ambient temperatures during initial and recurring stack testing.

D. The Permittee shall perform one set of tests on this CTG when burning natural gas with the duct burner and one set without duct firing. The Permittee shall perform one set of tests with the CTG burning ULSD.

E. Initial Performance Testing

1. Initial stack emission testing for the CTG is required for the following pollutant(s):
   - PM$_{10/2.5}$ (includes filterable and condensable)
   - SO$_2$
   - NO$_x$
   - CO
   - CO$_2$
   - VOC
   - Opacity
   - Other (HAPs): Sulfuric Acid, Formaldehyde (gas firing only)

2. Compliance with the VOC emission limits shall be determined by correlating the VOC emissions with a monitored parameter or pollutant during the initial stack testing for this unit. The Permittee shall submit a modification to this permit within 60 days of such testing to incorporate the monitoring methodology to be used for VOC emission compliance.

3. Stack emissions testing for the CTG firing natural gas, without duct firing, for CO$_2$ shall be required to show compliance with an emissions limit of 816 lb/MW-hr (net), corrected to ISO conditions, as defined in the approved stack test protocol.

4. Performance testing shall be required to show compliance with the heat rate found in Part II.G of this permit.

5. Initial stack testing for the auxiliary boiler in Part VI.A of this permit is required for the following pollutants:
   - NO$_x$
   - CO
   - VOC

6. The Permittee shall conduct initial stack testing no later than 180 days after initial startup. The Permittee shall submit test results within 60 days after completion of testing.
F. Recurrent Performance Testing

1. Recurrent stack testing for the CTG shall be performed within five years from the date of the previous stack test for the following pollutants:

   ☑ PM$_{10/2.5}$ (includes filterable and condensable)  ☑ SO$_2$  ☑ NO$_x$  ☑ CO
   ☑ VOC  ☑ Opacity  ☑ Other (HAP's): Sulfuric Acid, Formaldehyde (gas firing only)

   After the initial stack test, stack testing may not be required for pollutants using CEM. The commissioner retains the right to require stack testing of any pollutant at any time.

2. Recurrent performance testing shall be required within five years from the date of the previous test to show compliance with the heat rate found in Part II.G of this permit.

3. Recurrent stack testing for the auxiliary boiler in Part VI.A of this permit shall be performed within five years from the date of the previous stack test for the following pollutants:

   ☑ NO$_x$  ☑ CO  ☑ VOC

4. Recurrent testing shall be required at least once every five years from the date of the last test, unless otherwise noted, but no less than 9 calendar months or no more than 15 calendar months from the required test date.

G. Stack emission test results shall be reported in the applicable units for each pollutant found in Part III.A of this permit.

PART VI. COLLATERAL CONDITIONS FOR AUXILIARY COMBUSTION SOURCES (EU-2 through EU-5)

A. EU-2: 84 MMBtu/hr Natural Gas Fired Boiler with FGR

1. Operational Conditions
   a. Make and Model: TBD
   b. Allowable Fuels: Natural Gas
   c. Maximum Allowable Fuel Use over any consecutive 12 month period: 375,875,500 ft$^3$
   d. This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR Part 60, Appendix A, Reference Method 9.
   e. The Permittee shall comply with all applicable sections of the following New Source Performance Standards.

Title 40 CFR Part 60 Subparts Dc and A7

2. Allowable Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/MMBtu</th>
<th>ppmvd @ 3% O₂</th>
<th>tons per 12 consecutive months</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM₂₀.₅</td>
<td>0.005</td>
<td></td>
<td>0.97</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>0.005</td>
<td></td>
<td>0.97</td>
</tr>
<tr>
<td>NOₓ</td>
<td>0.0085</td>
<td>7.0</td>
<td>1.64</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.0015</td>
<td></td>
<td>0.29</td>
</tr>
<tr>
<td>VOC</td>
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<td></td>
<td>0.78</td>
</tr>
<tr>
<td>CO</td>
<td>0.037</td>
<td>50</td>
<td>7.14</td>
</tr>
<tr>
<td>Lead</td>
<td>4.9E-07</td>
<td></td>
<td>9.5E-05</td>
</tr>
<tr>
<td>H₂SO₄</td>
<td>1.1E-04</td>
<td></td>
<td>0.02</td>
</tr>
<tr>
<td>CO₂e</td>
<td>116.98</td>
<td></td>
<td>22,610</td>
</tr>
</tbody>
</table>

Demonstration of compliance with the above emission limits may be met by using emission factors from the following sources:

- SO₂ and H₂SO₄: Calculated from fuel sulfur content
- NOₓ, VOC, CO, Opacity: Most Recent Stack Test Data
- PM₁₀/₂₀.₅: Vendor Emissions Guarantee
- CO₂e: 40 CFR Part 98 Subpart C, Tables C-1 and C-2

3. Monitoring
   a. The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter or a billing meter.
   b. The Permittee shall perform inspections of the burners and flue gas recirculation (FGR) system as recommended by the manufacturer.

4. Record Keeping
   a. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month’s fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.
   b. The Permittee shall calculate and record the monthly and consecutive 12 month PM, PM₁₀, PM₂₀.₅, SO₂, NOₓ, VOC, CO, and CO₂e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month’s emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.
   c. The Permittee shall make and keep records of all maintenance and tune-up activities for this unit.
   d. The Permittee shall make and keep records of all inspections of the burners and FGR system.
   e. The Permittee shall make and keep records of all hours of simultaneous operation of this unit with the CTG. The Permittee shall total these hours for each month and for the calendar year. The Permittee shall make these calculations within 30 days of the end of the previous month.
   f. The Permittee shall make and keep records of manufacturer written specifications and recommendations for operation and maintenance.
   g. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.
5. Reporting
a. The Permittee shall comply with the record keeping and reporting requirements in 40 CFR §60.49b.
b. The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

6. Stack emission test requirements:
Stack emission testing shall be conducted as required in Part V of this perm

B. EU-4: 305 bhp Emergency Fire Pump

1. Operational Conditions
a. Make and Model: Clarke JU6-H-UFADX8
b. Allowable Fuel: ULSD
c. Maximum ULSD Sulfur Content (% by weight, dry basis): 0.0015
d. Maximum Allowable Fuel Use over any consecutive 12 month period: 4,380 gallons
e. This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR Part 60, Appendix A, Reference Method 9.
f. The Permittee shall not operate this emergency engine and the emergency engine operating under permit number 089-0108 individually for more than 300 hours per calendar year or more than 500 hours per calendar year in combination per calendar year.
g. The Permittee shall comply with all applicable sections of the following New Source Performance Standards at all times.

Title 40 CFR Part 60 Subparts III and A


2. Allowable Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/MMBtu</th>
<th>g/bhp-hr</th>
<th>Tons per 12 consecutive months</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM_{2.5}</td>
<td>0.05</td>
<td>0.15</td>
<td>0.015</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>0.05</td>
<td>0.15</td>
<td>0.015</td>
</tr>
<tr>
<td>NOx</td>
<td>3.0</td>
<td></td>
<td>0.30</td>
</tr>
<tr>
<td>SO_{2}</td>
<td>0.0015</td>
<td></td>
<td>5E-04</td>
</tr>
<tr>
<td>VOC</td>
<td></td>
<td>0.15</td>
<td>0.02</td>
</tr>
<tr>
<td>CO</td>
<td></td>
<td>2.6</td>
<td>0.26</td>
</tr>
<tr>
<td>H_{2}SO_{4}</td>
<td>1.1E-04</td>
<td></td>
<td>3.0E-05</td>
</tr>
<tr>
<td>CO_{2}</td>
<td>163.1</td>
<td></td>
<td>49</td>
</tr>
</tbody>
</table>

Demonstration of compliance with the above emission limits may be met by calculating the using emission factors from the following sources:

- SO_{2} and H_{2}SO_{4}: Calculated from fuel sulfur content
- NOx, PM_{10/2.5}, VOC, CO: Vendor Emissions Guarantee
- CO_{2}: 40 CFR Part 98 Subpart C, Tables C-1 and C-2
3. Monitoring
   a. The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable
totalizing fuel meter.
   b. The Permittee shall monitor all hours that this unit is in operation.

4. Record Keeping
   a. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The
      consecutive 12 month fuel consumption shall be determined by adding the current month's
      fuel consumption to that of the previous 11 months. The Permittee shall make these
      calculations within 30 days of the end of the previous month.
   b. The Permittee shall keep records of the fuel certification for each delivery of fuel oil from a
      bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the
      fuel used by the equipment that includes the applicable sulfur content of the fuel as a
      condition of each shipment. The shipping receipt or contract shall include the date of
      delivery, the name of the fuel supplier, type of fuel delivered, the percentage of sulfur in
      such fuel, by weight, dry basis, and the method used to determine the sulfur content of such
      fuel.
   c. The Permittee shall calculate and record the monthly and consecutive 12 month $PM_{10}, PM_{2.5},$
      $SO_2, NO_x, VOC, CO, H_2SO_4,$ and $CO_{2e}$ emissions in units of tons. The consecutive 12 month
      emissions shall be determined by adding (for each pollutant) the current month's emissions to
      that of the previous 11 months. Such records shall include a sample calculation for each
      pollutant. The Permittee shall make these calculations within 30 days of the end of the
      previous month.
   d. The Permittee shall keep records of the monthly and calendar year hours of operation for
      this unit.

Such records shall contain the following information:
   i. reason for operating;
   ii. date of event;
   iii. duration of event (minutes);
   iv. gallons of fuel combusted;
   v. for any testing or scheduled maintenance operation, the ozone level as forecasted for the
      day;
   vi. total engine hours of operation and total combined engine hours of operation with the
      emergency generator engine (EU-3, Permit Number 089-0108).

   e. The Permittee shall keep records of the inspection and maintenance for this engine. The
      records shall include:
         i. the name of the person conducting the inspection or maintenance;
         ii. the date of the inspection or maintenance;
         iii. the results or actions taken.
   f. The Permittee shall keep records of the manufacturer's specifications and written
      recommendations.
   g. The Permittee shall keep all records required by this permit for a period of no less than five
      years and shall submit such records to the commissioner upon request.

5. Reporting
   a. The Permittee shall comply with the reporting requirements in 40 CFR §60.4214.
   b. The Permittee shall notify the commissioner, in writing, of the date of commencement of
      construction and the date of initial startup of this equipment. Such written notifications shall
      be submitted no later than 30 days after the subject event.
C. EU-5: 5 MMBtu/hr Natural Gas Heater

1. Operational Conditions
   a. Make and Model: TERI or equivalent
   b. Allowable Fuel: Natural Gas
   c. Maximum Allowable Fuel Use over any consecutive 12 month period: 19,455,253 ft³
   d. This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR Part 60, Appendix A, Reference Method 9.

2. Allowable Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/MMBtu</th>
<th>Tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM&lt;sub&gt;2.5&lt;/sub&gt;</td>
<td>0.005</td>
<td>0.05</td>
</tr>
<tr>
<td>PM&lt;sub&gt;10&lt;/sub&gt;</td>
<td>0.005</td>
<td>0.05</td>
</tr>
<tr>
<td>NO&lt;sub&gt;x&lt;/sub&gt;</td>
<td>0.012</td>
<td>0.12</td>
</tr>
<tr>
<td>SO&lt;sub&gt;2&lt;/sub&gt;</td>
<td>0.0015</td>
<td>0.015</td>
</tr>
<tr>
<td>VOC</td>
<td>0.0034</td>
<td>0.03</td>
</tr>
<tr>
<td>CO</td>
<td>0.037</td>
<td>0.37</td>
</tr>
<tr>
<td>H&lt;sub&gt;2&lt;/sub&gt;SO&lt;sub&gt;4&lt;/sub&gt;</td>
<td>1.1E-04</td>
<td>0.001</td>
</tr>
<tr>
<td>CO&lt;sub&gt;2&lt;/sub&gt;</td>
<td>116.98</td>
<td>1,170</td>
</tr>
</tbody>
</table>

Demonstration of compliance with the above emission limits may be met by using emission factors from the following sources:

- SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub>: Calculated from fuel sulfur content
- NO<sub>x</sub>, PM<sub>10</sub>/PM<sub>2.5</sub>, VOC, CO: Vendor Emissions Guarantee
- CO<sub>2</sub>e: 40 CFR Part 98 Subpart C, Tables C-1 and C-2

3. Monitoring
   The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter.

4. Record Keeping
   a. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.
   b. The Permittee shall calculate and record the monthly and consecutive 12 month PM<sub>2.5</sub>, PM<sub>10</sub>, NO<sub>x</sub>, SO<sub>2</sub>, VOC, CO, and CO<sub>2</sub>e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.
   c. The Permittee shall make and keep records of all maintenance and tune-up activities for this unit.
   d. The Permittee shall make and keep records of all inspections of the burner system.
   e. The Permittee shall make and keep records of manufacturer written specifications and recommendations for operation and maintenance.
   f. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.
5. Reporting

The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART VII. SPECIAL REQUIREMENTS

A. The Permittee shall possess, at least, 163 tons of external emissions reductions to offset the quantity of NOx emitted from the following sources to comply with RCSA Section 22a-174-3a(1):

- EU-1: Siemens SGT6-8000HCTG Combustion Turbine, Permit Number 089-0107
- EU-2: 84 MMBtu/hr natural gas fired auxiliary boiler, Permit Number 089-0107
- EU-3: 1,380 kW emergency generator engine, Permit Number 089-0108
- EU-4: 305 bhp emergency fire pump engine, Permit Number 089-0107
- EU-5: 5 MMBtu/hr natural gas fired heater, Permit Number 089-107

Such a quantity is sufficient to offset the emissions from the sources listed above at a ratio of 1.2 to 1 for every ton of NOx emissions allowed under this permit. Specifically, the reductions are real, quantifiable, surplus, permanent, and enforceable as defined in RCSA Section 22a-174-3a(1)(5). The Permittee shall maintain sole ownership and possession of these emissions reductions for the duration of this permit and any subsequent changes to the permit.

Such offsets have been obtained from the following sources:

- 112.64 tons from Glenwood Combustion Turbine Facility: (NY-DEC-1-2822-00481-112.64)
- 50.36 tons from National Grid Far Rockaway Power Station: (NY-DEC-2-6308-00040-50.36)

The offsets were approved by the Department on June 14, 2017. The Permittee shall maintain sole ownership and possession of these emissions reductions for the duration of this permit and any subsequent changes to the permit.

The Permittee may be required to obtain additional NOx offsets and complete additional ambient air quality analysis to show that the NAAQS and PSD increments have not been violated, if observed Steady-State or Transient emissions exceed limits specified in Parts III.A, III.B or III.C of this permit.

The commissioner may require other methods for determining NOx emissions from these sources as allowed by state or federal statute, law or regulation.

B. Upon completion of construction of the CTG and control equipment, the Permittee shall prepare and submit a written standby plan in accordance with the RCSA Sections 22a-174-6(c)(2) through (d)(5).

C. The Permittee shall operate this facility at all times in a manner so as not to violate or contribute significantly to the violation of any applicable state noise control regulations, as set forth in RCSA Sections 22a-69-1 through 22a-69-7.4. [STATE ONLY REQUIREMENT]

D. The Permittee shall resubmit for review and approval a Best Available Control Technology (BACT) analysis if such construction or phased construction has not commenced within the 18 months following the commissioner's approval of the current BACT determination (i.e., the Issue date of this permit) for such construction or phase of construction. [RCSA Section 22a-174-3a(j)(4)]
PART VIII. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of the DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.
BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

<table>
<thead>
<tr>
<th>Owner/Operator</th>
<th>NTE Connecticut, LLC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Address</td>
<td>24 Cathedral Place, Suite 300 Saint Augustine, FL 32084</td>
</tr>
<tr>
<td>Equipment Location</td>
<td>180/189 Lake Road, Killingly, CT 06241</td>
</tr>
<tr>
<td>Equipment Description</td>
<td>Cummins 1250DQGAE 1,380 kW Emergency Engine</td>
</tr>
<tr>
<td>Collateral Conditions</td>
<td>Part II.A of this permit contains collateral conditions for one 305 bhp emergency fire pump engine identified in permit number 089-0107 as EU-4.</td>
</tr>
<tr>
<td>Town-Permit Numbers</td>
<td>089-0108</td>
</tr>
<tr>
<td>Premises Number</td>
<td>101</td>
</tr>
<tr>
<td>Stack Number</td>
<td>2</td>
</tr>
<tr>
<td>Permit Issue Date</td>
<td>JUN 30 2017</td>
</tr>
<tr>
<td>Expiration Date</td>
<td>None</td>
</tr>
</tbody>
</table>

Robert J. Klee
Commissioner

Date: 6/30/2017

ORIGINAL
This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

NTE Connecticut operates a Cummins 1250DQGAE 1,380 kW ULSD fired emergency engine, identified as EU-3, to provide emergency back-up power to the facility. The generator is not connected to the electrical grid and is only utilized as an emergency engine. The unit is also subject to 40 CFR Part 60 Subpart III.

B. Equipment Design Specifications

1. Allowable Fuel Type: Ultra Low Sulfur Distillate (ULSD)
2. Maximum Fuel Firing Rate (gal/hr): 90.9
3. Maximum Gross Heat Input (MMBTU/hr): 12.54

C. Stack Parameters

1. Minimum Stack Height (ft): 25
2. Minimum Exhaust Gas Flow Rate at maximum firing rate (acfm): 6,600
3. Minimum Stack Exit Temperature at maximum firing rate (°F): 840
4. Minimum Distance from Stack to Property Line (ft): 440

PART II. OPERATIONAL CONDITIONS

A. Equipment

1. This equipment shall fire only Ultra Low Sulfur Distillate (ULSD).
2. Maximum Fuel Consumption over any Consecutive 12 Month Period: 27,270 gallons
3. Maximum Fuel Sulfur Content: 0.0015% by weight
4. The Permittee may operate this source for up to 300 hours per calendar year, but not more than 500 hours per calendar year in combination with the emergency fire pump identified as EU-4 in permit number 089-0107.
5. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.
6. The Permittee shall operate and maintain this equipment and any monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.
B. For Emergency Use

1. This emission unit shall only operate in accordance with the definition of emergency engine as defined in RCSA Sections 22a-174-22 and 22a-174-22e.

2. The Permittee shall not operate the subject engine for routine scheduled testing or maintenance during days when ambient ozone is forecasted by the commissioner to be
   a. "moderate unhealthy for sensitive groups" to "very unhealthy", or
   b. "moderate to unhealthy for sensitive groups" or greater, after June 1, 2018, anywhere in Connecticut.
   c. Forecast Information

Official ambient ozone information can be obtained by calling:
   i. (860) 424-4167 Department's Bureau of Air Management Monitoring Section
      (Recorded Message Updated daily at 3:00 p.m.)
   ii. (860) 424-3027 Department's Bureau of Air Management Monitoring Section
      (For additional air quality information)

PART III. ALLOWABLE EMISSION LIMITS

The Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time.

A. Short Term Emission Limits

1. Criteria Pollutants

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/MMBtu</th>
<th>g/kW-hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>0.05</td>
<td>0.20</td>
</tr>
<tr>
<td>PM_{10/2.5}</td>
<td>0.05</td>
<td>0.20</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.0015</td>
<td></td>
</tr>
<tr>
<td>NOₓ</td>
<td></td>
<td>6.4</td>
</tr>
<tr>
<td>VOC</td>
<td></td>
<td>0.32</td>
</tr>
<tr>
<td>CO</td>
<td></td>
<td>3.5</td>
</tr>
<tr>
<td>Pb</td>
<td>1.4E-05</td>
<td></td>
</tr>
<tr>
<td>H₂SO₄</td>
<td>1.1E-04</td>
<td></td>
</tr>
<tr>
<td>CO₂</td>
<td>163.1</td>
<td></td>
</tr>
</tbody>
</table>
B. Annual Emission Limits

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per 12 consecutively months</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>0.09</td>
</tr>
<tr>
<td>PM$_{10/2.5}$</td>
<td>0.09</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>0.003</td>
</tr>
<tr>
<td>NO$_x$</td>
<td>2.92</td>
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<tr>
<td>VOC</td>
<td>0.15</td>
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<tr>
<td>CO</td>
<td>1.60</td>
</tr>
<tr>
<td>Pb</td>
<td>2.0E-05</td>
</tr>
<tr>
<td>H$_2$SO$_4$</td>
<td>2.0E-04</td>
</tr>
<tr>
<td>CO$_2$e</td>
<td>308</td>
</tr>
</tbody>
</table>

C. Hazardous Air Pollutants

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

D. Opacity

Opacity resulting from operation of this engine shall not exceed 10% during any six-minute block average or 40% reduced to a one-minute block average; as measured by 40 CFR Part 60, Appendix A, Reference Method 9.

E. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

- SO$_2$, H$_2$SO$_4$. Calculated from fuel sulfur content
- NO$_x$, PM$_{10/2.5}$, VOC, CO: EPA Certified Vendor Emissions Factor
- Pb: AP-42 Sec. 3.1
- CO$_2$: 40 CFR Part 98 Subpart C, Table C-1
- CO$_2$e: 40 CFR Part 98 Subpart C, Table C-2

The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter.

2. The Permittee shall monitor all hours that this unit is in operation.
B. Record Keeping

1. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month’s fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. The Permittee shall keep records of the fuel certification for each delivery of fuel oil from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the fuel used by the equipment that includes the applicable sulfur content of the fuel as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the fuel supplier, type of fuel delivered, the percentage of sulfur in such fuel, by weight, dry basis, and the method used to determine the sulfur content of such fuel.

3. The Permittee shall calculate and record the monthly and consecutive 12 month PM$_{10}$, PM$_{2.5}$, SO$_2$, NO$_x$, VOC, CO, H$_2$SO$_4$, and CO$_2$e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month’s emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

4. The Permittee shall keep monthly and calendar year records of all hours of operation and fuel use for this unit.

   Such records shall contain the following information:
   a. reason for operating;
   b. date of event;
   c. duration of event (minutes);
   d. gallons of fuel combusted;
   e. for any testing or scheduled maintenance operation, the ozone level as forecasted for the day;
   f. total engine hours of operation and total combined engine hours of operation with the fire pump identified in permit 089-0107. (EU-4).

5. The Permittee shall keep records of the inspection and maintenance for this engine. The records shall include:
   a. the name of the person conducting the inspection or maintenance;
   b. the date of the inspection or maintenance;
   c. the results or actions taken.

6. The Permittee shall comply with the applicable record keeping requirements of RCSA Sections 22a-174-22(I) and 22a-174-22e(I).

7. The Permittee shall keep records of the manufacturer’s specifications and written recommendations.

8. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.
C. Reporting

1. The Permittee shall comply with the applicable reporting requirements of RCSA Sections 22a-174-22(l) and 22a-174-22e(k).

2. The Permittee shall comply with the reporting requirements in 40 CFR §60.4214.

3. The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. SPECIAL REQUIREMENTS

A. The Permittee shall comply with all applicable sections of the following New Source Performance Standards at all times.

Title 40 CFR Part 60, Subparts IIII and A


B. The Permittee shall not cause or permit the emission of any substance or combination of substances which creates or contributes to an odor beyond the property boundary of the premises that constitutes a nuisance as set forth in RCSA Section 22a-174-23. [STATE ONLY REQUIREMENT]

PART VI. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of the DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true,"
accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.
Exhibit 4
Disclaimer:

This document was produced by DEQ. Some of its content may not be in an accessible format pursuant to Section 508 of the federal Rehabilitation Act of 1973, as amended (29 U.S.C. § 794 (d)). Please call 800-592-5482 if you need assistance.
June 24, 2019

Mr. Irfan K. Ali
Managing Partner
Balico LLC/Chickahominy Power
1380 Coppermine Road, Suite 115
Herndon, VA 20171

Location: Charles City County
Registration No.: 52610

Dear Mr. Ali:

Attached is a permit to construct and operate an electric power generation facility in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on January 10, 2019 and solicited written public comments by placing a newspaper advertisement in the Charles City/New Kent Chronicle on January 31, 2019. A public hearing was held on March 5, 2019. The required comment period, provided by 9 VAC 5-80-1775 F expired on March 20, 2019.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

This permit approval to construct and operate shall not relieve Chickahominy Power of the responsibility to comply with all other local, state, and federal permit regulations. The proposed combustion turbine generators are affected facilities under 40 CFR 60, New Source Performance Standard (NSPS), Subpart TTTT. Also, your proposed diesel emergency generator (EG-1) and diesel emergency fire water pump (FWP-1) may be subject to 40 CFR 60, New Source Performance Standard (NSPS), Subpart III and 40 CFR 63, Maximum Achievable Control Technology (MACT), Subpart ZZZZ. In summary, the units may be required to comply with certain federal emission standards and operating limitations. The DEQ advises you to review the referenced NSPS and MACT to ensure compliance with applicable emission and
operational limitations. As the owner/operator you are also responsible for monitoring, notification, reporting and recordkeeping requirements of the NSPS and MACT. Notifications shall be sent to both EPA Region III and Virginia DEQ.

To review any federal rules referenced in the above paragraph or in the attached permit, the US Government Publishing Office maintains the text of these rules at [www.ecfr.gov](http://www.ecfr.gov), Title 40, Part 60 and 63.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director  
Department of Environmental Quality  
P. O. Box 1105  
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please contact the regional office at (804) 527-5020.

Sincerely,

Michael Dowd  
Director, Air and Renewable Energy Division

MGD/SMF/52610_01_2019 Final Issued Permit

Attachments: Permit  
Source Testing Report Format

cc: Chief, Office of Air Enforcement and Compliance Assistance, U.S. EPA, Region III  
(electronic file submission)  
Inspector, Air Compliance
PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia
Regulations for the Control and Abatement of Air Pollution,

Balico LLC/Chickahominy Power
1380 Coppermine Road, Suite 115
Herndon, Virginia 20171
Registration No.: 52610

is authorized to construct and operate

an electric power generation facility

located at

the east side of State Road 106 (Roxbury Rd), along
Chambers/Landfill Road, Charles City, VA

in accordance with the Conditions of this permit.

Approved on June 24, 2019.

Director, Air and Renewable Energy Division
Department of Environmental Quality

Permit consists of 29 pages.
Permit Conditions 1 to 81.
INTRODUCTION

This permit approval is based on the permit application dated February 22, 2017; including amendment information dated November 2, 2018 and January 10, 2019. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

**Equipment List** – Equipment at this facility consists of:

### Equipment to be constructed:

<table>
<thead>
<tr>
<th>Ref. No.</th>
<th>Equipment Description</th>
<th>Rated Capacity</th>
<th>Federal Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT-1</td>
<td>Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator</td>
<td>4,070 MMBtu/hr CT (HHV)</td>
<td>NSPS, Subpart KKKK</td>
</tr>
<tr>
<td>CT-2</td>
<td>Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator</td>
<td>4,070 MMBtu/hr CT (HHV)</td>
<td>NSPS, Subpart KKKK</td>
</tr>
<tr>
<td>CT-3</td>
<td>Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generator</td>
<td>4,070 MMBtu/hr CT (HHV)</td>
<td>NSPS, Subpart KKKK</td>
</tr>
<tr>
<td>HRSG1, 2, &amp; 3 each with a steam turbine generator</td>
<td>Mitsubishi heat recovery steam generators (HRSGs) with steam turbine generators</td>
<td>178 MW each at ISO</td>
<td>None</td>
</tr>
</tbody>
</table>

### Ancillary equipment:

<table>
<thead>
<tr>
<th>Ref. No.</th>
<th>Equipment Description</th>
<th>Rated Capacity</th>
<th>Federal Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>B-1</td>
<td>Auxiliary Boiler (natural gas-fired)</td>
<td>84 MMBtu/hr (HHV)</td>
<td>NSPS Subpart Dc</td>
</tr>
<tr>
<td>B-2</td>
<td>Auxiliary Boiler (natural gas-fired)</td>
<td>84 MMBtu/hr (HHV)</td>
<td>NSPS Subpart Dc</td>
</tr>
<tr>
<td>FGH-1</td>
<td>Fuel Gas Heater (natural gas-fired)</td>
<td>12 MMBtu/hr each (HHV)</td>
<td>NSPS Subpart Dc</td>
</tr>
<tr>
<td>FGH-2</td>
<td>Fuel Gas Heater (natural gas-fired)</td>
<td>12 MMBtu/hr each (HHV)</td>
<td>NSPS Subpart Dc</td>
</tr>
</tbody>
</table>
Specifications included in the above table are for informational purposes only and do not form enforceable terms or conditions of the permit.

**PROCESS REQUIREMENTS**

**Combustion Turbine Generators (CT-1, CT-2, CT-3)**

1. **Emission Controls: Combustion Turbine Generators** - Nitrogen oxide (NOx) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by dry, low NOx burners and selective catalytic reduction (SCR) with a NOx performance of 2.0 ppmvd at 15% O2. The low NOx burners shall be installed and operated in accordance with manufacturer’s specifications. The SCR shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

2. **Monitoring Devices: Combustion Turbine Generators - SCR** - Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer’s written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating. To ensure good performance of the SCR, the devices used to continuously measure the ammonia feed rate and catalyst bed inlet temperature on the SCR shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system, but not less than once per day of operation.

(9 VAC 5-50-20 C, 9 VAC 5-50-50 H and 9 VAC 5-80-1705 B)

3. **Emission Controls: Combustion Turbine Generators** – Carbon monoxide (CO) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

4. **Emission Controls: Combustion Turbine Generators** – Volatile organic compound (VOC) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be
controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

5. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer’s written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating. To ensure good performance of the oxidation catalyst system, the device used to continuously measure and record the catalyst bed inlet and outlet gas temperature on the oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst system, but not less than once per day of operation.
(9 VAC 5-50-20 C, 9 VAC 5-50-50 H and 9 VAC 5-80-1705 B)

6. **Emission Controls: Combustion Turbine Generators** – Sulfur dioxide (SO₂) and sulfuric acid mist (H₂SO₄) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 22.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

7. **Emission Controls: Combustion Turbine Generators** – Particulate Matter (PM, PM₁₀, PM₂₅) emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time) and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

8. **Emission Controls: Combustion Turbine Generators** – Greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxide), as CO₂e from the combustion turbine generators (CT-1, CT-2, CT-3) shall be controlled by the use of low carbon fuel (natural gas) and high efficiency design and operation of the combustion turbine generators (CT-1, CT-2, CT-3 and steam turbine generator). The heat rate of the combustion turbine generators (CT-1, CT-2, CT-3 and steam turbine generator) at full load, corrected to ISO conditions, and providing for incremental degradation of the units, shall not exceed the following:

<table>
<thead>
<tr>
<th>Year</th>
<th>Btu/kWh net (HHV) output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Test</td>
<td>6,452</td>
</tr>
<tr>
<td>Year 6</td>
<td>6,581</td>
</tr>
<tr>
<td>Year 12</td>
<td>6,677</td>
</tr>
<tr>
<td>Year 18</td>
<td>6,775</td>
</tr>
<tr>
<td>Year 24</td>
<td>6,871</td>
</tr>
</tbody>
</table>
Compliance shall be demonstrated as contained in Conditions 62 and 65. The Year is defined in Condition 35. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

9. **Startup/Shutdown: Combustion Turbine Generators** – The permittee shall comply with the requirements of this permit at all times except where noted by a specific condition. For the purpose of this permit, this condition defines startup and shutdown operating scenarios for the combustion turbine generators (CT-1, CT-2, CT-3).

a. Startup periods are defined as follows:

i. For the purpose of this permit, startup is defined as the time from combustion turbine ignition to the HRSG stack NOx and CO steady state emission compliance (see Condition 34.a) or the duration of the event periods indicated in items ii through iv below, whichever is shorter:

ii. Cold Startup Event: cold startup is defined as restarts made 48 hours or more after shutdown. Cold startup events shall not exceed 42 minutes per occurrence.

iii. Warm Startup Event: warm startup is defined as restarts made more than 8 but less than 48 hours after shutdown. Warm startup events shall not exceed 42 minutes per occurrence.

iv. Hot Startup Event: hot startup is defined as restarts made less than 8 hours after shutdown. Hot startup events shall not exceed 42 minutes per occurrence.

b. Shutdown Event: For the purpose of this permit, a shutdown event is defined as the moment at which either the HRSG stack NOx or CO emissions exceed steady state compliance (see Condition 34.a) following a normal stop signal, until the cessation of fuel firing in the combustion turbine generators (CT-1, CT-2, CT-3). Shutdown shall not exceed 15 minutes per occurrence.

c. If the SCR was not engaged during startup of a particular combustion turbine (including ammonia injection), the failure of that startup shall not be considered a shutdown as defined in 9.b.

d. The permittee shall operate the Continuous Emission Monitoring System (CEMS) during periods of startup and shutdown.

e. The permittee shall record the time, date and duration of each startup and shutdown event. The records must include calculations of NOx and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

f. If the applicable NOx and CO emission limits in Condition 34.d are exceeded during these events, the recorded emissions shall be included in the associated quarterly excess emission report.
g. During startup and shutdown, the combustion turbine generator SCR system, including ammonia injection, and oxidation catalyst shall be operated in a manner to minimize emissions, as technologically feasible, and following the SCR manufacturer’s written protocol or best engineering practices for minimizing emissions. Where best practices are used, the permittee shall maintain written documentation explaining the sufficiency of such practices. If such practices are used in lieu of the manufacturer’s protocol, the documentation shall justify why the practices are at least equivalent to manufacturer’s protocols with respect to minimizing emissions.

(9 VAC 5-50-280 and 9 VAC 5-80-1705)

10. **Alternate Operating Scenario: Combustion Turbine Generators – Tuning Events** – Periodic burner tuning is done by the permittee as part of the regularly scheduled procedures conducted on the CTs to maintain the high-efficiency operation of those units. The following conditions apply to these alternative operating scenarios:

a. No tuning event shall last more than 18 consecutive hours.

b. The permittee shall record the time, date and duration of each tuning event. The records must include calculations of NOx and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

c. If the applicable NOx and CO emission limits in Condition 34.b are exceeded during these events, the recorded emissions shall be included in the associated quarterly excess emission report.

d. The permittee shall notify the Piedmont Regional Office at least 24 hours prior to each declared turning event unless approval for a shorter notice is provided by DEQ. The notification shall include, but not be limited to, the following information:

i. Identification of the specific turbine to be tuned;

ii. Reason for the declared turning event; and

iii. Measures that will be taken to minimize the duration of the declared turning event.

(9 VAC 5-20-180J and 9 VAC 5-50-20E)

**Auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3)**

11. **Emission Controls: Fuel Gas Heaters and Auxiliary Boilers** – NOx emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by low NOx burners with a NOx performance of 0.011 lbs/MMBtu. The low NOx burners shall be installed and operated in accordance with manufacturer’s specifications.

(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

12. **Emission Controls: Fuel Gas Heaters and Auxiliary Boilers** – CO and VOC emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by good combustion practices (controlled fuel/air, adequate temperature, and adequate gas residence time), operator training, and proper emissions unit design, construction and maintenance to achieve a maximum CO emission rate of 0.037 lb/MMBtu and a maximum VOC emission rate of 0.005 lb/MMBtu. Boiler and heater operators shall be
trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at a minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boilers and heater. These procedures shall be based on the manufacturer's recommendations and/or best engineering practices, at a minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.

(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

13. **Emission Controls: Fuel Gas Heaters and Auxiliary Boilers** – SO₂ and H₂SO₄ emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 22 for the combustion turbine generators.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

14. **Emission Controls: Fuel Gas Heaters and Auxiliary Boilers** – PM, PM₁₀, and PM₂.₅ emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 22.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

15. **Emission Controls: Fuel Gas Heaters and Auxiliary Boilers** – CO₂e emissions from the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3) shall be controlled by the use of natural gas fuel and high efficiency design and operation.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

**Emergency Units (EG-1 and FWP-1)**

16. **Emission Controls: EG-1, FWP-1** – PM, PM₁₀, PM₂.₅, NOₓ, CO, SO₂, VOC, H₂SO₄, and CO₂e emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by good combustion practices, high efficiency design, and the use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

17. **Emission Controls: EG-1, FWP-1** – CO₂e emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by the use of S15 ULSD and high efficiency design and operation.

(9 VAC 5-80-1705B and 9 VAC 5-50-280)

18. **Monitoring Devices: EG-1** – The permittee must install a non-resettable hour meter on the emergency generator (EG-1) and the emergency fire water pump (FWP-1) prior to the startup of each unit. The hour meters shall be provided with adequate access for inspection.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)
Miscellaneous Processes

19. **Emission Controls: Equipment Leaks** – Fugitive emissions from natural gas piping components (valves and flanges) located on the power plant property (NGL-1) shall be minimized by using best management practices to prevent, detect and repair leaks of natural gas from the piping components. At commencement of commercial operation, the permittee shall implement a daily auditory/visual/olfactory (AVO) inspection program for detecting leaking in natural gas piping components. Records of the daily AVO inspection results, repair attempts, and repair results shall be maintained on site. The AVO plan shall be submitted for review no later than 60 days prior to commencement of commercial operation of the facility.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

20. **Emission Controls: Electrical Breakers** – The total combined capacity of the electrical circuit breakers shall not exceed 22,800 lbs of SF₆. Greenhouse gas emissions (including SF₆) from the circuit breakers (CB) shall be controlled by an enclosed-pressure circuit breaker, with a maximum annual leakage rate of 0.5 percent, and a low pressure detection system (with alarm). The low pressure detection system shall be in operation when the circuit breakers are in use. The permittee shall develop a maintenance plan for the circuit breakers that includes procedures for minimizing emissions and corrective action to be taken in the event of a low pressure alarm. The permittee shall keep records of the total quantity of SF₆ gas added to the circuit breakers in a calendar year.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

**OPERATING LIMITATIONS**

21. **Fuel Throughput: Combustion Turbine Generators** – Each of the three combustion turbine generators (CT-1, CT-2, CT-3) shall consume no more than a total of 3.5 x 10¹⁰ scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

22. **Fuel Monitoring: Combustion Turbine Generators** – The permittee shall determine the total sulfur content of the natural gas being fired at the electric power generation facility to verify that the sulfur content of the natural gas is less than or equal to 0.4 grains of total sulfur per 100 scf on a 12-month rolling average in order to demonstrate that potential sulfur dioxide and sulfurous acid mist emissions shall not exceed the limits specified in Condition 34.a for the combustions turbine generators (CT-1, CT-2, CT-3). The permittee shall demonstrate compliance with the sulfur content limit in Condition 24 using one of the following:

a. Determine and record the total sulfur content of the natural gas each month. A monthly sample is not required for months when the turbines operated for 48 hours or less, or

b. Develop custom schedules for determination of the sulfur content of the natural gas based on the design and operation of the affected facility and the characteristics of the fuel
supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval. (9 VAC 5-50-410, 9 VAC 5-50-280, 40 CFR 60.4365(a), 40 CFR 60.4370(b), and 40 CFR 60.4370(c))

23. **Alternate Operating Scenario Limitation: Combustion Turbine Generators** – The total duration of turbine tuning events shall not exceed 96 hours per turbine per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

24. **Fuel: Combustion Turbine Generators, Fuel Gas Heaters, and Auxiliary boilers** - The approved fuel for the combustion turbine generators (CT-1, CT-2, CT-3), fuel gas heaters (FGH-1, FGH-2, FGH-3), and the auxiliary boilers (B-1, B-2) is pipeline quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average basis. A change in the fuel may require a permit to modify and operate. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

25. **Fuel Throughput: Auxiliary Boilers** - Each of the two auxiliary boilers (B-1, B-2) shall consume no more than $7.21 \times 10^8$ scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

26. **Fuel Throughput: Fuel Gas Heaters** – Each of the fuel gas heaters (FGH-1, FGH-2, FGH-3) shall consume no more than $1.03 \times 10^8$ scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

27. **Fuel: EG-1 and FWP-1** - The approved fuel for the emergency diesel fire water pump (FWP-1) and emergency diesel generator (EG-1) is ultra-low sulfur diesel (S15 ULSD). A change in the fuel may require a permit to modify and operate. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

28. **Fuel: EG-1 and FWP-1** - The fuel for the fire pump (FWP-1) and emergency generator (EG-1) shall meet the specifications below:

ULTRA-LOW SULFUR DIESEL FUEL (S15 ULSD) which meets the ASTM D975-10b specification for S15 fuel oil: Maximum sulfur content per shipment: 0.0015%

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)
29. **Operating Hours: EG-1 and FWP-1** - The emergency generator (EG-1) and emergency firewater pump (FWP-1) shall not operate more than 500 hours each per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

30. **Emergency Operation: EG-1 and FWP-1** – The emergency diesel engine (EG-1) and firewater pump (FWP-1) shall only be operated in the following modes:

   a. In situations that arises from sudden and reasonably unforeseeable events where the primary energy or power source is disrupted or disconnected due to conditions beyond the control of an owner or operator of a facility including:

      i. A failure of the electrical grid;

      ii. On-site disaster or equipment failure; or

      iii. Public service emergencies such as flood, fire, natural disaster, or severe weather conditions.

   b. For participation in an ISO-declared emergency, where an ISO emergency is:

      i. An abnormal system condition requiring manual or automatic action to maintain system frequency, to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property;

      ii. Capacity deficiency or capacity excess conditions;

      iii. A fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel;

      iv. Abnormal natural events or man-made threats that would require conservative operations to posture the system in a more reliable state; or

      v. An abnormal event external to the ISO service territory that may require ISO action.

   c. For periodic maintenance, testing, and operational training.

Total emissions for any 12 month period, calculated as the sum of all emissions from operations under the scenarios above, shall not exceed the annual limits (tons/yr) stated in Condition 39 for the firewater pump (FWP-1) and Condition 40 for the emergency generator (EG-1). (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

31. **Fuel Certification: EG-1 and FWP-1** - The permittee shall obtain a certification from the fuel supplier with each shipment of S15 ULSD oil. Each fuel supplier certification shall include the following:

   a. The name of the fuel supplier;

   b. The date on which the S15 ULSD oil was received;
c. The quantity of S15 ULSD oil delivered in the shipment;
d. A statement from the supplier that the fuel oil is S15 ULSD oil;

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 28. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

32. **Maintenance and Operation: EG-1 and FWP-1** – The permittee must maintain and operate the emergency fire pump (FWP-1) and emergency generator (EG-1) according to the manufacturer’s recommendations and/or procedures developed by the permittee using best engineering practices, over the entire life of the engine. (9 VAC 5-80-1705 B and 9 VAC 5-50-280)

33. **Requirements by Reference: NSPS** - Except where this permit is more restrictive than the applicable requirement, the NSPS equipment as described in the equipment table in the Introduction on page 2 of this permit shall be operated in compliance with the requirements of 40 CFR 60, Subparts Dc, IIII, and KKKK. (9 VAC 5-50-400 and 9 VAC 5-50-410)

**EMISSION LIMITS**

34. **Short-Term Emission Limits: Combustion Turbine Generators** - Emissions from the operation of each combustion turbine generator (CT-1, CT-2, CT-3), shall not exceed the limits specified below:

a. Normal operation – The limits in the table below apply as described in the “Applicability” column. Periods considered startup and shutdown are defined in Condition 9 of this permit, and alternate operating scenarios are defined in Condition 10.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Short term emission limits</th>
<th>Applicability</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM_{filterable only}</td>
<td>0.0052 lb/MMBtu</td>
<td>This limit applies at all times except tuning. See item b below.</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>0.0052 lb/MMBtu</td>
<td>These limits apply at all times except during tuning. See item b below.</td>
</tr>
<tr>
<td></td>
<td>12.3 lb/hr as an average of three test runs.</td>
<td></td>
</tr>
<tr>
<td>PM_{2.5}</td>
<td>0.0052 lb/MMBtu</td>
<td>These limits apply at all times except during tuning. See item b below.</td>
</tr>
<tr>
<td></td>
<td>12.3 lb/hr as an average of three test runs</td>
<td></td>
</tr>
<tr>
<td>SO_{2}</td>
<td>0.00114 lb/MMBtu</td>
<td>This limit applies at all times.</td>
</tr>
<tr>
<td>NO_{x}</td>
<td>2.0 ppmvd @ 15% O_{2} as a one-hour average</td>
<td>This limit applies at all times except during startup, shutdown, and tuning. See items b and d below.</td>
</tr>
<tr>
<td>CO</td>
<td>1.0 ppmvd @ 15% O_{2}</td>
<td>This limit applies at all times except during startup, shutdown, and tuning. See items b and d below.</td>
</tr>
</tbody>
</table>
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Pollutant | Short term emission limits | Applicability
--- | --- | ---
VOC | 0.7 ppmvd @ 15% O₂ | This limit applies at all times except during startup, shutdown, and tuning. See items b and d below.
H₂SO₄ | 0.0012 lb/MMBtu | This limit applies at all times.

Where:
ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O₂.

Short-term emission limits represent averages for a three-hour sampling period for CO, VOC, SO₂ and H₂SO₄. Nitrogen oxides shall be calculated as a one-hour average. PM, PM₁₀ and PM₂.₅ limits represent the average of three test runs.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 1, 3, 4, 6, 7, 21, 22, 45, 56, 57, and 60.

b. During each CT tuning event as described in Condition 10, emissions shall not exceed the following limits:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Limitations for Tuning Events</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOₓ</td>
<td>703 lb/turbine/calendar day</td>
</tr>
<tr>
<td>CO</td>
<td>214 lb/turbine/calendar day</td>
</tr>
<tr>
<td>VOC</td>
<td>Duration of tuning events shall not exceed limits in Condition 10.</td>
</tr>
<tr>
<td>PM, PM₁₀, PM₂.₅</td>
<td>Duration of tuning events shall not exceed limits in Condition 10.</td>
</tr>
</tbody>
</table>

The emissions limits for tuning events do not include emissions from startup and/or shutdown that may occur on the same calendar day.

c. NOₓ emission concentrations shall not exceed the NOₓ standards of the NSPS Subpart KKKK of 15 ppm at loads > 75% or 96 ppm at loads ≤ 75% corrected to 15% O₂ (on a rolling 30-day average basis).

d. During each startup or shutdown event, emissions shall not exceed the following:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Startup/Shutdown Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOₓ</td>
<td>cold start event – 60 lb/turbine/event</td>
</tr>
<tr>
<td></td>
<td>warm start event – 54 lb/turbine/event</td>
</tr>
<tr>
<td></td>
<td>hot start event – 42 lb/turbine/event</td>
</tr>
<tr>
<td></td>
<td>shutdown event – 20 lb/turbine/event</td>
</tr>
<tr>
<td>CO</td>
<td>cold start event – 444 lb/turbine/event</td>
</tr>
<tr>
<td></td>
<td>warm start event – 396 lb/turbine/event</td>
</tr>
<tr>
<td></td>
<td>hot start event – 252 lb/turbine/event</td>
</tr>
<tr>
<td></td>
<td>shutdown event – 156 lb/turbine/event</td>
</tr>
<tr>
<td>VOC</td>
<td>cold start event – 216 lb/turbine/event</td>
</tr>
<tr>
<td></td>
<td>warm start event – 216 lb/turbine/event</td>
</tr>
</tbody>
</table>
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Pollutant | Startup/Shutdown Limitations
---|---
hot start event – | 168 lb/turbine/event
shutdown event – | 216 lb/turbine/event

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with the NOx and CO limits shall be determined as stated in Conditions 9 and 45. Compliance with the VOC limits may be determined by demonstrating correlation of VOC emissions to CO emissions, using CO and VOC stack testing and CO CEM data.

(9 VAC 5-50-280, 9 VAC 5-80-1705, 9 VAC 5-80-1715)

35. **Emission Limits: Combustion Turbine Generators** – CO$_2$e emissions from each of the combustion turbine generators (CT-1, CT-2, CT-3) and the steam turbines, providing for incremental degradation of the units, shall not exceed the following:

<table>
<thead>
<tr>
<th>Degradation Period</th>
<th>Applicable limit in lb CO$_2$e/MWh net output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Years 1-6</td>
<td>812</td>
</tr>
<tr>
<td>Years 7-12</td>
<td>824</td>
</tr>
<tr>
<td>Years 13-18</td>
<td>836</td>
</tr>
<tr>
<td>Years 19-24</td>
<td>847</td>
</tr>
<tr>
<td>Years 25-30</td>
<td>859</td>
</tr>
<tr>
<td>Years 31 and later</td>
<td>871</td>
</tr>
</tbody>
</table>

For the purposes of determining which limit is applicable, Year 1 begins upon commencement of commercial operation and ends on December 31 of the first full calendar year after that date. Each limit increments on January 1 of the respective year. For example, if the facility commences commercial operation on April 15, 2021, Year 1 begins on April 15, 2021 and ends on December 31, 2022. Year 7 begins, and the increased limit becomes effective, on January 1, 2028.

Compliance with the applicable limit shall be calculated monthly on a 12-month rolling basis. Compliance may be determined each month by summing the calculated CO$_2$e emissions from the combustion turbine generators (CT-1, CT-2, CT-3) during the previous 12 months (Condition 47) and dividing that value by the sum of the electrical energy output over that same period (Condition 48).

(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

36. **Annual Process Emission Limits: Combustion Turbine Generators** – Emissions from the operation of each of the three combustion turbine generators (CT-1, CT-2, CT-3) shall not exceed the limits specified below:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>53.9 tons/yr</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>53.9 tons/yr</td>
</tr>
<tr>
<td>PM$_{2.5}$</td>
<td>53.9 tons/yr</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>20.4 tons/yr</td>
</tr>
</tbody>
</table>

(on a 12-month, rolling total)
These emissions are derived from the estimated overall emission contribution from operating limits, and include periods of startup and shutdown, and tuning. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits shall be determined as stated in Conditions 1, 3, 4, 6, 7, 21, 22, 23, 45, and 47.

(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

37. **Process Emission Limits: Auxiliary Boilers** – Emissions from the operation of each of the auxiliary boilers (B-1, B-2) shall not exceed the limits specified below:

<table>
<thead>
<tr>
<th>Emission</th>
<th>Limit</th>
<th>Units</th>
<th>Total Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>128.4</td>
<td>tons/yr</td>
<td>(on a 12-month, rolling total)</td>
</tr>
<tr>
<td>CO</td>
<td>94.3</td>
<td>tons/yr</td>
<td>(on a 12-month, rolling total)</td>
</tr>
<tr>
<td>VOC</td>
<td>68.1</td>
<td>tons/yr</td>
<td>(on a 12-month, rolling total)</td>
</tr>
<tr>
<td>H₂SO₄</td>
<td>21.4</td>
<td>tons/yr</td>
<td>(on a 12-month, rolling total)</td>
</tr>
<tr>
<td>CO₂e</td>
<td>2,123,519</td>
<td>tons/yr</td>
<td>(on a 12-month, rolling total)</td>
</tr>
</tbody>
</table>

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits shall be determined as stated in Conditions 11, 12, 13, 14, 15, 24, 25, 43, 59, and 61.

(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

38. **Process Emission Limits: Electrical Breakers** - Emissions from the operation of the electrical circuit breakers (CB-1) shall not exceed 1,140 tons of CO₂e/year on a 12 month, rolling average. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits shall be determined as stated in Condition 20.

(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

39. **Process Emission Limits: FWP-1** - Emissions from the operation of the fire water pump (FWP-1) shall not exceed the limits specified below:
PM 0.15 g/hp-hr
PM$_{10}$ 0.15 g/hp-hr
PM$_{2.5}$ 0.15 g/hp-hr
NO$_x$ 3.0 g/hp-hr 0.7 tons/yr (on a 12-month rolling total)
CO 2.6 g/hp-hr 0.6 tons/yr (on a 12-month rolling total)
VOC 0.11 g/hp-hr
SO$_2$ 0.00154 lb/MMBtu
H$_2$SO$_4$ 0.000118 lb/MMBtu
CO$_2$e 106 tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits shall be determined as stated in Conditions 27, 28, 29, 30, 32 and 44.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

40. **Process Emission Limits: EG-1** - Emissions from the operation of the diesel emergency generator (EG-1) shall not exceed the limits specified below:

PM 0.15 g/hp-hr
PM$_{10}$ 0.15 g/hp-hr
PM$_{2.5}$ 0.15 g/hp-hr
NO$_x$ 4.8 g/hp-hr 11.7 tons/yr (on a 12-month rolling total)
CO 2.6 g/hp-hr 6.4 tons/yr (on a 12-month rolling total)
VOC 1.0 g/hp-hr
SO$_2$ 0.00154 lb/MMBtu
H$_2$SO$_4$ 0.000118 lb/MMBtu
CO$_2$e 1,203 tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits shall be determined as stated in Conditions 27, 28, 29, 30, 32, and 44.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

41. **Process Emission Limits: Fuel Gas Heaters** – Emissions from the operation of each of the fuel gas heaters (FGH-1, FGH-2, FGH-3) shall not exceed the limits specified below:

PM 0.4 tons/yr (on a 12-month rolling total)
PM$_{10}$ 0.4 tons/yr (on a 12-month rolling total)
CONTINUOUS EMISSION MONITORING SYSTEMS

42. **Visible Emission Limit: Combustion Turbine Generators** - Visible emissions from the combustion turbine generators (CT-1, CT-2, CT-3) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).

(9 VAC 5-50-80 and 9 VAC 5-50-280)

43. **Visible Emission Limit: Fuel Gas Heaters and Auxiliary Boilers** - Visible emissions from the fuel gas heaters (FGH-1, FGH-2, FGH-3) and auxiliary boilers (B-1, B-2) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).

(9 VAC 5-50-80 and 9 VAC 5-50-280)

44. **Visible Emission Limit: EG-1 and FWP-1** - Visible emissions from the emergency fire water pump (FWP-1) and diesel emergency generator (EG-1) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).

(9 VAC 5-50-80 and 9 VAC 5-50-280)

CONTINUOUS MONITORING SYSTEMS

45. **CEMS: Combustion Turbine Generators** - Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO\textsubscript{x} (measured as NO\textsubscript{2}) and CO from each combustion turbine generator (CT-1, CT-2, CT-3) in ppmvd, corrected to 15 percent O\textsubscript{2}. CEMS for NO\textsubscript{x} shall meet the design specifications of 40 CFR Part 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the monitoring requirements in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO\textsubscript{x} and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75.11 (d) and (e) shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 34.a, NO\textsubscript{x} data shall be reduced to 1-hour block averages. CO data shall be reduced to 3-hour rolling averages.
46. **CEMS Performance Evaluations** - Performance evaluations of the NO₃ and, if applicable, SO₂ CEMS shall be conducted in accordance with 40 CFR Part 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. Two copies of the performance evaluations report shall be submitted to the Piedmont Region within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Piedmont Region.

(9 VAC 5-50-350 and 9 VAC 5-50-40)

47. **Continuous Monitoring: Combustion Turbine Generators – Greenhouse gases – CO₂** emissions from each combustion turbine generator (CT-1, CT-2, CT-3) shall be monitored using one of the methods in 40 CFR Part 75.13. The permittee shall notify the Piedmont Regional Office as to which method was used to determine the emissions of CO₂ from the turbines. The methods in Appendix G to 40 CFR Part 75, shall be used to report annual CO₂ emissions. CH₄ and N₂O emissions shall be calculated using fuel heat value data and the emission factors found in 40 CFR Part 98, Subpart C, Table C-2. Annual CO₂e emissions shall be calculated using the global warming potential factors found in 40 CFR Part 98, Subpart A, Table A-1 for CO₂, CH₄ and N₂O.

(9 VAC 5-50-50)

48. **Continuous Monitoring: Net Power Output and Fuel Flow** – The permittee shall continuously monitor the net electrical output of each combustion turbine generator and associated steam turbine (CT-1, CT-2, CT-3), measured at the generator terminals, and the fuel flow to each combustion turbine generator to show compliance with the applicable emission limitation in Condition 35 on a 12-operating month rolling basis.

(9 VAC 5-50-40F)

49. **Continuous Monitoring Quality Control Program** - A CMS quality control program which is equivalent to the requirements of 40 CFR 75 Appendix B shall be implemented for all continuous monitoring systems.

(9 VAC 5-50-350 and 9 VAC 5-50-40)

50. **CEMS Emissions Data** – For the purposes of this permit and DEQ’s emissions inventory, CEMS data shall be used to report annual emissions of NOₓ and CO from the stack of each combustion turbine generator (CT-1, CT-2, CT-3) in tons/yr.

(9 VAC 5-50-50)

51. **CEMS: Excess Emissions and Monitor Downtime for NOₓ and CO** - For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 53 are defined as follows:
a. An excess emission period is an operating period in which the NO\textsubscript{x} emission rate exceeds the applicable emission limits in Condition 34.a, 34.b, 34.c, or 34.d;

b. An excess emission period is an operating period in which the CO emission rate exceeds the applicable emission limits in Condition 34.a, 34.b, or 34.d; and

c. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO\textsubscript{x} concentration, CO concentration, O\textsubscript{2} concentration, fuel flow rate, steam pressure, or megawatts. The steam flow rate is only required if the permittee uses this information for compliance purposes. (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

52. Continuous Monitoring Systems: Excess Emissions and Monitor Downtime for SO\textsubscript{2} - Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

a. Excess emissions of SO\textsubscript{2} from the combustion turbine generators occurs when the 12-month rolling average sulfur content of the fuel being fired in the combustion turbine generators (CT-1, CT-2, CT-3) exceeds the applicable limit in Condition 6 based on monthly fuel testing in Condition 22. The excess emission period ends on the date that 12-month rolling average sulfur content of the fuel demonstrates compliance with the sulfur limit; and

b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date of the next valid sample. (9 VAC 5-50-50, 9 VAC 5-50-280)

53. Continuous Monitoring Excess Emissions Reports - The permittee shall furnish written reports to the Piedmont Region of excess emissions from any process monitored by a continuous monitoring system on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.
e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.
(9 VAC 5-50-50)

54. CEMS: Excess Emissions – For purposes of identifying excess emissions:
   a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);
   b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19.0 percent O2 may be used in the emission calculations; and
   c. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Appendix D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).
(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

INITIAL COMPLIANCE DETERMINATION

55. Emissions Testing: Facility - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from excessive cyclonic flow as defined in 40 CFR 60 Appendix A. Sampling ports shall be provided at the appropriate locations (in accordance with the applicable performance specification in 40 CFR Part 60, Appendix B) and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1675)

56. Initial Performance Test: Combustion Turbine Generators - Initial performance tests shall be conducted for CO, PM, PM10, PM2.5, and total VOC from each combustion turbine generator (CT-1, CT-2, CT-3) to determine compliance with the emission limits contained in Condition 34.a. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted at full load. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy
57. **Initial Performance Test: Combustion Turbine Generators** – Initial performance tests shall be conducted on each combustion turbine generator (CT-1, CT-2, CT-3) for NOₓ (as NO₂) to determine compliance with the limits contained in Condition 34.a using 40 CFR 60, Appendix A, Methods 7E or 20 to measure the NOₓ concentration (in ppm) and following the performance test specifications found in 40 CFR 60.4400. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit. (9 VAC 5-50-30, 9 VAC 5-50-410, and 9 VAC 5-50-1675)

58. **Initial Performance Test: Combustion Turbine Generators** – Initial performance tests shall be conducted on each combustion turbine generator (CT-1, CT-2, CT-3) for SO₂ to determine compliance with the limits contained in Condition 34.a. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manually sampling using Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO₂ concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9-10-1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO₂ and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).
The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 58.a above, no test protocol or test report is required, however the permittee shall notify the Piedmont Regional Office as to which method was used to determine the total sulfur content of the fuel sample.
(9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-1675)

59. **Initial Performance Test: Auxiliary Boilers and Fuel Gas Heaters** - Initial performance tests shall be conducted for NOx and CO from the auxiliary boilers (B-1, B-2) and the fuel gas heaters (FGH-1, FGH-2, FGH-3) to determine compliance with the emission limits contained in Conditions 11 and 12, as applicable. The tests shall be performed, reported and demonstrate compliance within 60 days after the boilers or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial start-up. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1985 E, and 9 VAC 5-50-410)

60. **Visible Emissions Evaluation: Combustion Turbine Generators** - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combustion turbine generator (CT-1, CT-2, CT-3). Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The VEE shall be conducted at full load. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)
61. Visible Emissions Evaluation: Auxiliary Boilers and Fuel Gas Heaters - Concurrently with the initial performance tests required in Condition 59, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each of the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boilers will be operated but in no event later than 180 days after start-up of the boiler. Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

62. Testing: Power Block Heat Rate - Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) or equivalent method approved by the Piedmont Regional Office, shall be conducted for the heat rate of the power blocks (i.e., a combination of CT-1, CT-2, CT-3 and the steam turbine generators) to show compliance with the initial limit contained in Condition 8. The testing shall be performed, reported and demonstrate compliance within 90 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after commencement of commercial operation of the permitted facility. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

CONTINUING COMPLIANCE DETERMINATION

63. Continuing Compliance: Combustion Turbine Generators – The permittee shall conduct additional performance tests for VOC, PM_{10} and PM_{2.5} from the combustion turbine generators (CT-1, CT-2, CT-3) to demonstrate compliance with the emission limits contained in this permit every five years. The tests shall occur no less than 54 months and no more than 66 months after the previous test. The details of the tests shall be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

64. Annual Performance Test: Combustion Turbine Generators – Annual performance tests shall be conducted on each combustion turbine generator (CT-1, CT-2, CT-3) for SO_{2} to determine compliance with the limits contained in Condition 34.a. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:
a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manual sampling using the Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D5504, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO₂ concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO₂ and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 64.a above, no test protocol or test report is required, however the permittee shall notify the Piedmont Regional Office as to which method was used to determine the total sulfur content of the fuel sample.
(9 VAC 5-50-30, 9 VAC 5-50-410)

65. Periodic Testing: Power Block Heat Rate—The permittee shall conduct subsequent heat rate testing of the power blocks in accordance with Condition 62 to show compliance with the applicable heat rate contained in Condition 8 in Years 6, 12, 18, 24 and 30. After Year 30, additional tests shall be conducted between 60 and 73 months after the previous test. The details of the evaluation are to be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

66. Stack Tests: Continuing Compliance—Upon request by DEQ, the permittee shall conduct additional performance tests to determine compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 G)
RECORDS

67. **On Site Records: Facility** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Region. These records shall include, but are not limited to:

a. Annual hours of operation of the emergency fire water pump (FWP-1) and emergency generator (EG-1) for emergency purposes, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

b. All fuel supplier certifications for the S15 ULSD fuel used in the diesel emergency units (EG-1 and FWP-1);

c. Monthly and annual throughput of natural gas to each of the three combustion turbine generators (CT-1, CT-2, CT-3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

d. Monthly and annual throughput of natural gas to each of the auxiliary boilers (B-1, B-2) and fuel gas heaters (FGH-1, FGH-2, FGH-3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

e. Fuel sulfur monitoring records for the natural gas combusted in the combustion turbine generators (CT-1, CT-2, CT-3), auxiliary boilers (B-1, B-2), and fuel gas heaters (FGH-1, FGH-2, FGH-3);

f. Monthly and annual net power output of the combustion turbine generators and associated steam turbines (CT-1, CT-2, CT-3).

g. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions;

h. Operation and control device monitoring records for each SCR system and oxidation catalyst as required in Conditions 2 and 5;

i. Records of alternative operating scenarios as required by Conditions 9, 10, and 23;

j. The occurrence and duration of any startup, shutdown, or malfunction of the affected facility, any malfunction of the air pollution control equipment, or any periods during which a continuous emission monitoring system is inoperative;

k. Results of daily AVO inspections for fugitive natural gas leak detection from the piping and components, including any repairs or other records required by Condition 19.

l. Scheduled and unscheduled maintenance, and operator training.
m. Results of all stack tests, power block heat rate tests, visible emission evaluations, and performance evaluations.

n. Manufacturer’s instructions for proper operation of equipment.

o. Records showing the circuit breakers are operating in accordance with the manufacturer’s specifications (see Condition 20).

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50 and 9 VAC 5-50-410)

NOTIFICATIONS

68. Initial Notifications - The permittee shall furnish written notification to the Piedmont Regional Office of:

a. The actual date on which construction of the electric power generation facility commenced within 30 days after such date.

b. The anticipated start-up date of the electric power generation facility postmarked not more than 60 days nor less than 30 days prior to such date.

c. The actual start-up date of the electric power generation facility within 15 days after such date.

d. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

e. The anticipated date of performance tests of the combustion turbine generators (CT-1, CT-2, CT-3), auxiliary boilers (B-1, B-2), and the fuel gas heaters (FGH-1, FGH-2, FGH-3), postmarked at least 30 days prior to such date.

Copies of the written notification referenced in items a through e above are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029
(9 VAC 5-50-50 and 9 VAC 5-50-410)

AMBIENT AIR QUALITY MONITORING

69. Ambient Air Quality Monitoring – The permittee shall conduct ambient air monitoring for PM$_{2.5}$ beginning upon startup of the facility. No later than 180 days prior to startup of the facility, the permittee shall submit an Ambient Air Quality Monitoring Quality Assurance Project Plan (QAPP) for approval by DEQ. The Quality Assurance Project Plan shall be developed consistent with the requirements of EPA’s "Guide to Writing Quality Assurance Project Plans for Ambient Air Monitoring Networks" (EPA-454/8-18-006):
a. The permittee shall not certify ambient monitoring data without an approved QAPP.

b. The plan shall include, at a minimum, all the elements described in EPA-454/8-18-006 in addition to the following elements:

i. Description of the site selection process for air quality monitors;

ii. Description of procedures for all aspects of the operation of monitoring equipment including maintenance, data processing, data validation, data reporting and data certification. These procedures shall be developed consistent with the requirements described in EPA's "Guidance for Preparing Standard Operating Procedures (SOPs)" (EPAQA/G-6). The SOPs shall be submitted for approval along with the QAPP;

iii. All monitoring and associated tasks shall conform to, at a minimum, the applicable requirements of 40 CFR Parts 50, 53, and 58, and any other requirements specified by DEQ;

iv. Performance Evaluations (PE) for all monitoring equipment installed consistent with these conditions shall be performed by the permittee or their designated representative. These PEs shall be performed consistent with the requirements of 40 CFR Part 58, Appendix A Section 3. Results of the PEs shall be submitted to DEQ 3 months after the performance date of the PE. The permittee shall be responsible for submitting the results of the PE to the EPA Air Quality Subsystem database. If the PE does not meet the requirements of 40 CFR Part 58 section 3, DEQ shall be notified prior to the submittal of the data to the AQS database. This notification is to include any remedial action taken or planned to be taken by the permittee to bring the system into compliance with the requirements of 40 CFR Part 58, Section 3; or

v. A plan for making the collected data available to the public subject to DEQ's approval. This information shall be included in the QAPP. DEQ will approve the monitoring location(s) based on EPA's siting criteria and the proximity to the maximum modeled impact from the power station for PM2.5 in consultation with local interested stakeholders.

(9 VAC 5-80-1735 B)

GENERAL CONDITIONS

70. Permit Invalidation –This permit to construct the electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

a. A program of continuous construction or modification is not commenced within 18 months from the date of this permit.

b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.

(9 VAC 5-80-1985)

71. Permit Suspension/Revocation - This permit may be suspended or revoked if the permittee:
a. Knowingly makes material misstatements in the permit application or any amendments to it;

b. Fails to comply with the conditions of this permit;

c. Fails to comply with any emission standards applicable to a permitted emissions unit;

d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or

e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

(9 VAC 5-80-1985 F)

72. Right of Entry - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.

(9 VAC 5-170-130 and 9 VAC 5-80-1180)

73. Maintenance/Operating Procedures – At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such
equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request. (9 VAC 5-50-20 E)

74. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record. (9VAC 5-20-180 J)

75. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Piedmont Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone, email, or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Piedmont Regional Office. (9 VAC 5-20-180 C)

76. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated. (9 VAC 5-20-180 I)

77. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Piedmont Regional Office of the change of ownership within 30 days of the transfer. (9 VAC 5-80-1985 E)

78. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies. (9 VAC 5-80-1985 E)

**STATE-ONLY ENFORCEABLE REQUIREMENTS**

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-40-130 et seq., 9 VAC 5-50-130 et seq., 9 VAC 5-60-200 et seq. and/or 9 VAC 5-60-300 et seq. and are enforceable only by the Virginia Air Pollution Control Board. Neither their
inclusion in this permit nor any resulting public comment period make these terms federally enforceable.

79. **Emission Limits: Toxic Air Pollutants** – Emissions from the electric power generation facility shall not exceed the limits specified below:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>CAS#</th>
<th>Lb/hr</th>
<th>Tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acrolein</td>
<td>107-02-8</td>
<td>0.051</td>
<td>0.23</td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>50-00-0</td>
<td>2.26</td>
<td>9.86</td>
</tr>
<tr>
<td>Beryllium</td>
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<td>0.00015</td>
<td>0.00064</td>
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<tr>
<td>Cadmium</td>
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<td>0.059</td>
</tr>
<tr>
<td>Chromium</td>
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<td>0.075</td>
</tr>
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<td>Lead</td>
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</tr>
<tr>
<td>Mercury</td>
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<td>0.014</td>
</tr>
<tr>
<td>Nickel</td>
<td>7440-02-0</td>
<td>0.026</td>
<td>0.12</td>
</tr>
</tbody>
</table>

*Hourly emissions of these pollutants are exempt

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits shall be determined as stated in Conditions 4, 7, 9, 21, 80, and 81.

(9 VAC 5-60-320 and 9 VAC 5-80-1625G)

80. **(SOE) Stack Test: Toxic Air Pollutants** – An initial performance test shall be conducted for formaldehyde from each combustion turbine generator (CT-1, CT-2, CT-3) to determine compliance with the emission limits contained in Condition 79. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted at full load. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.

(9 VAC 5-50-30 and 9 VAC 5-80-1675)

81. **(SOE) On Site Records: Toxic Air Pollutants** – The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Regional Office. These records shall include, but are not limited to the average hourly (in pounds), monthly (in tons), and annual emissions (in tons) of each toxic compound listed in Condition 79. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These records shall be available for inspection by DEQ and current for at least the most recent five years.

(9 VAC 5-50-50 and 9 VAC 5-80-1625G)
SOURCE TESTING REPORT FORMAT

Report Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

Certification
1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. *Signed by reviewer

Copy of approved test protocol

Summary
1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. *For each emission unit, a table showing:
   a. Operating rate
   b. Test Methods
   c. Pollutants tested
   d. Test results for each run and the run average
   e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

Test Results
1. Detailed test results for each run
2. *Sample calculations
3. *Description of collected samples, to include audits when applicable

Appendix
1. *Raw production data
2. *Raw field data
3. *Laboratory reports
4. *Chain of custody records for lab samples
5. *Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

* Not applicable to visible emission evaluations