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JEA Brandy Branch
Fuel Flexibility

B&V Project 133972
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Project No.: 0310485-007-AC
0310485-008-AV

Subject: Lower Sulfur Fuel Oil Operation

On behalf of JEA, Black & Veatch is submitting this letter report summarizing JEA's proposed use of lower sulfur fuel oil and an associated increase in oil firing hours for the simple cycle combustion turbine (SCCT) and the two combined cycle combustion turbines (CCCT) at the Brandy Branch facility. This letter report is a technical support document for the Prevention of Significant Deterioration (PSD) Air Permit addendum and Title V revision application. The following sections of this letter contain the project history, project description, and attachments containing an air quality impact analysis (AQIA) and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of a revised air construction permit and a revised Title V air operating permit for the Brandy Branch Generating Station. Required FDEP application forms are also included as an attachment to this letter. This submittal serves as an addendum to the original PSD permit application and is not considered a modification of an existing major source.

Project History

The JEA Brandy Branch Generating Station (hereinafter referred to as the "Generating Station") near Baldwin City, Duval County, Florida was originally permitted to construct three SCCT units (Permit No. PSD-FL-267). Two fuel oil storage tanks and related support facilities were included as part of the original permit and have already been

installed. The three SCCTs permitted were limited to a total of 4,750 hr/yr operation on pipeline natural gas (2.0 grains sulfur / 100 scf) (hereinafter, referred to as 2.0 natural gas) but air dispersion modeling was performed using natural gas (0.2 grains sulfur / 100 scf) (hereinafter, referred to as 0.2 natural gas). Additionally, each SCCT was permitted with 750 hr/yr of No. 2 distillate fuel oil (0.05 % sulfur) (hereinafter, referred to as No. 2 fuel oil) firing. Based on the AQIA, each SCCT was limited to no more than 16 hr/day of No. 2 fuel oil firing with the remainder on 0.2 natural gas.

It should be noted that a screening level regional haze analysis was conducted for Okefenokee Class I area using the ISC air dispersion model. The initial screening results indicated that the Brandy Branch facility may cause or contribute to haze values greater than 5%. Thus, JEA limited daily No. 2 fuel oil firing to 16 hr/day per SCCT. Additionally, as indicated in Condition #14 of Permit No. PSD-FL-267, so as to cause a net benefit to the nearby Class I areas, JEA retired the Southside Facility and surrendered related permits (AIRS ID 0310046).

A subsequent construction permit (Permit No. PSD-FL-310) allowed for conversion of two of the three SCCT units to CCCT units. The conversion of the two SCCT units to CCCT units with supplemental firing in the heat recovery steam generator (HRSG) is currently in the construction phase. Related support facilities were permitted along with the CCCT units which will be operated in a 2x1 configuration. No additional No. 2 fuel oil storage was permitted with the conversion to the CCCT units and no additional No. 2 fuel oil storage capacity was requested.

The submitted PSD permit revision for the CCCTs reflected, based on a new AQIA, 8,760 hr/yr of firing 0.2 natural gas each and 576 hr/yr total of No. 2 fuel oil and no more than 16 hr/day firing No. 2 fuel oil with the remaining 8 hr/day firing 0.2 natural gas. During the review, EPA determined that the application was not a modification of an existing major source, but an addenda to the original PSD application. Therefore, the applicable PSD pollutants and air quality impact assessments should include the emissions associated with the operation of the two converted CCCT's and the previously permitted SCCT. Three separate air dispersion modeling analyses were submitted to FDEP and EPA in support of agency review for this revision (i.e., September 21, October 31, and November 7, 2001). The final AQIA reflected 8,760 hr/yr firing 0.2 natural gas each and two additional No. 2 fuel oil scenarios:

- The SCCT operating 16 hr/day on No. 2 fuel oil and the remainder of the day (8 hr) on 0.2 natural gas and simultaneously the two CCCTs operating 24 hr/day on 0.2 natural gas.
- One CCCT operating 16 hr/day on No. 2 fuel oil and the remainder of the day (8 hr) on 0.2 natural gas and simultaneously the SCCT and other CCCT operating 24 hr/day on 0.2 natural gas.

Both EPA and FDEP approved this final modeling analysis. During discussions with these agencies in regard to obtaining operational flexibility in the draft permit, JEA was notified that the original permit contained a BACT natural gas usage limit of 2.0 natural gas while the air dispersion modeling was performed using the 0.2 natural gas. In keeping with the schedule for issuance of the Conditions of Certification, JEA agreed to restrictive permit conditions with the option of investigating additional operating scenarios after permit issuance. The resulting final fuel firing operational limitations contained in the PSD Permit is for one combustion turbine (either one of the combined cycle turbines or the simple cycle turbine) operating on No. 2 fuel oil for 16 hr/day, with no additional hours of operation on 2.0 natural gas in any of the turbines (refer to PSD Permit No. PSD-FL-310, Condition #14).

On March 13, 2003 JEA submitted an application to revise their PSD Air Construction Permit for the Generating Station's two CCCT by increasing the duct burner size in each HRSG. Originally, the CCCT Units 2 and 3 were each permitted with a 2.0 natural gas fired duct burner, again while the air dispersion modeling was performed using the 0.2 natural gas. The permitted maximum heat input of each duct burner was 85 MMBtu/hr (HHV) and had a regulatory classification under 40 CFR Part 60 as a Dc unit. JEA submitted a request to increase each duct burner's maximum heat input from 85 MMBtu/hr to 170 MMBtu/hr (HHV). The change in duct burner size classified each burner as a Db unit. In support of this revision, an AQIA was submitted which demonstrated compliance with applicable PSD modeling thresholds. A permit revision was granted in the summer of 2003 incorporating the aforementioned duct burner changes.

The facility holds a Title V operating permit (Permit No. 0310485-005-AV) issued March 19, 2003. The CCCT units have not yet been incorporated into the Title V permit.

Project Description

As previously discussed, the Generating Station is currently permitted to construct and operate one SCCT (Unit 1) and two CCCTs (Units 2 and 3). Unit 1 is operational while Units 2 and 3 are currently operating as SCCT's while under construction for conversion to combined cycle units. Due to SO_2 ambient air quality impact concerns when firing 0.2 natural gas and No. 2 fuel oil, the existing permit includes restrictive short-term operating limits. JEA proposes to permit an alternate operating scenario allowing for use of 2.0 natural gas and a cleaner, lower sulfur fuel oil (0.0065% sulfur) (hereinafter, referred to as LSFO) for greater operational flexibility at the Generating Station while meeting compliance requirements.

Natural Gas

Condition #23 of PSD Permit No. PSD-FL-310 establishes that SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 2 grains / 100 scf). The discontinuity in sulfur content which was used in the air dispersion modeling performed for the combined cycle conversion (0.2 natural gas) and that which was assessed as BACT by FDEP (2.0 natural gas) was one of the factors which led to the restrictive operating limits in the current permit.

Additionally, the definition of pipeline natural gas and natural gas were revised on June 12, 2002 (Ref: 40411 FR Vol. 67 No. 113). The EPA has removed all references to hydrogen sulfide content in the new definition and has instead defined pipeline natural gas based on total sulfur. The definition of pipeline natural gas and natural gas as listed in the federal register and incorporated into the CFR Part 72.2, is provided below:

> ***Pipeline natural gas:*** *a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.*

> ***Natural gas**: a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.*

It is suggested that consistent language be used in referencing the sulfur content of pipeline quality natural gas and natural gas such that there is not a misinterpretation in the permit. To further clarify the permit and increase operational flexibility at the Generating Station, it is requested that language be included in the permit such that pipeline quality natural gas and/or natural gas are defined as containing 2 grains sulfur / 100 scf (2.0 natural gas). Thus, all references to this gaseous fuel throughout the permit can be consistently identified as either pipeline quality natural gas or natural gas. In order to revise the permit language to a more consistent basis, it has been assumed that a demonstration of compliance through air dispersion modeling would be required for the combustion turbines firing 2.0 natural gas. This issue has been addressed in the air dispersion modeling contained in Attachment 1 & 2 and is further described below as it relates to operation on LSFO.

Fuel Oil

Currently, all three units are permitted to fire 2.0 natural gas (although previously mentioned, air dispersion modeling was performed at 0.2 natural gas) and No. 2 fuel oil. Under the proposed additional operating scenario, JEA is requesting that the firing of a LSFO be permitted for use in all three combustion turbines in lieu of No. 2 fuel oil when it becomes commercially available for use in Florida. The use of 2.0 natural gas will still remain the primary fuel for the combustion turbines. In conjunction with permitting the use of LSFO, this application seeks to permit additional allowable hours of annual LSFO fuel oil firing and less restrictive daily operating limits as compared to the existing

stringent short-term permit limits as described in permit conditions for fuel oil firing scenarios as outlined in the FDEP PSD Air Construction Permit (PSD-FL-310), Condition #14 (page 7 of 14):

> *Maximum allowable hours of operation for the 540 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. The combined hours of fuel oil firing for the two combined cycle combustion turbines is limited to 576 hours per consecutive 12-month period and fuel oil firing for the simple cycle unit is limited to 750 hours per consecutive 12-month period. In the event that any of the 3 emission units (simple or combined cycle) fires fuel oil during a calendar day, that unit shall be limited to 16 hours of daily operation on any fuel. Additionally, the other 2 units shall not be fired on any fuel for the calendar day.*

No revisions to the operating restrictions or fuels are proposed for this existing condition as it pertains to operation with the 0.05% sulfur fuel oil. Until such time that LSFO is commercially available, JEA will comply with Condition #14, but requests revisions to the Condition to clarify the use of No. 2 fuel oil and 2.0 natural gas. In general, the suggested revisions to Condition #14 include the following for illustration purposes.

> *Maximum allowable hours of operation for the 540 MW Combined Cycle Plant are 8760 hours per year while firing natural gas (2.0 grains sulfur / 100scf). The combined hours of No. 2 distillate fuel oil (0.05% sulfur) firing for the two combined cycle combustion turbines is limited to 576 hours per consecutive 12-month period and No. 2 distillate fuel oil (0.05% sulfur) firing for the simple cycle unit is limited to 750 hours per consecutive 12-month period. In the event that any of the 3 emission units (simple or combined cycle) fires No. 2 distillate fuel oil (0.05% sulfur) during a calendar day, that unit shall be limited to 16 hours of daily operation on any fuel. Additionally, the other 2 units shall not be fired on any fuel for the calendar day.*

As LSFO becomes commercially available, and upon written notification by JEA, the following new condition is proposed to govern operation of the three combustion turbines. Again, for illustration purposes a general condition has been included.

Maximum allowable hours of operation for the 540 MW Combined Cycle Plant are 8,760 hours per year while firing natural gas (2.0 grains sulfur / 100 scf). The combined hours of lower sulfur fuel oil (0.0065% sulfur) firing for the two combined cycle combustion turbines is limited to 2,000 hours per consecutive 12-month period and lower sulfur fuel oil (0.0065% sulfur) firing for the simple cycle unit is limited to 1,000 hours per consecutive 12-month period. In the event that all 3 emission units (simple and combined cycle) fires lower sulfur fuel oil (0.0065% sulfur) during a calendar day, each combined cycle unit shall be allowed 24 hours of daily operation while the simple cycle unit shall be limited to 8 hours of daily operation. In the event that the simple cycle unit fires lower sulfur fuel oil (0.0065% sulfur) for more than 8 hours during a calendar day, it shall be allowed 24 hours of daily operation while the combined cycle units shall not be fired on any fuel for the calendar day.

However, it should be noted that JEA requests, upon written notification to FDEP, the ability to switch between No. 2 fuel oil or LSFO depending upon fuel availability. It is understood that other conditions and descriptions in the PSD permit (Permit No. PSD-FL-310) and the Generating Station Title V permit will require similar updates.

As previously discussed, air dispersion modeling has been performed to address the proposed alternate operating scenario based on the fuel sulfur contents reflecting LSFO containing 0.0065% sulfur and natural gas containing 2 grains sulfur/100 scf.

Air Dispersion Modeling

Included with this submittal are the results of air dispersion modeling demonstrating that relaxing the short term operational limits and allowing for increased annual hours of fuel oil firing when using the LSFO and 2.0 natural gas will not result in adverse ambient air impacts.

The modeling analyses followed the approved approach used in the previous modeling submittals for this permit (i.e., SCCT, CCCT, and Duct Burner Increase) and the air dispersion modeling protocol document submitted to FDEP on January 9, 2004. The modeling performed for the Class II demonstration was limited to using the EPA ISCST3

air dispersion model to predict pollutant concentrations for areas less than 50 km from the project. Specifically, the Class II area surrounding the project and Okefenokee National Wildlife Refuge (ONWR) Class I area were analyzed. Modeling performed for the Class I demonstration for predicted impacts for regional haze and deposition for Class I areas at distances greater than 50 km from the project was performed using the approved long-range transport model CALPUFF. A comparison of the Class II and Class I modeled impacts to the applicable Prevention of Significant Deterioration (PSD) Significant Impact Levels (SILs) for all pollutants for the proposed fuel changes were made. As each analysis indicates, the project's maximum predicted concentrations are less than the applicable PSD SILs. Therefore, under the PSD program, no further air quality impact analyses are required for the proposed alternate operating scenario firing the LSFO and 2.0 natural gas.

The air dispersion modeling technical support document and a CD-ROM containing the electronic air dispersion modeling files which demonstrate compliance with the PSD SILs has been enclosed with this document.

Basis of information

The information for the aforementioned permit addenda is based on the following:

- May 1999 SCCT application document and subsequent permit (Permit No. PSD-FL-267).
- December 2000 CCCT application document and subsequent permit (Permit No. PSD-FL-310).
- March 2003 Duct Burner administrative change submittal and subsequent amended permit summer 2003.
- Conversations with the fuel vendor and GE turbine manufacturer indicated that the LSFO will have no change to or effect the operation of the turbine or electrical generation, stack parameters (flows and temperatures), or pollutant emissions except for an SO_2 reduction.

Requested Actions

The purpose of this submittal is not only to obtain a construction permit revision allowing for the firing of LSFO, but it is also to incorporate this alternate operating scenario and the CCCT conversions into the Title V permit. Because the CCCT units have not yet begun operation, per §62-213.420(1)(a).4., F.A.C., this submittal includes a compliance

schedule and methodology for the CCCT units. Attachment 3 contains the FDEP application forms.

Based on the information submitted and the results of the ambient air quality analyses, it is requested that FDEP grant this revision to the Brandy Branch PSD Air Construction Permit (PSD-FL-310) and incorporate the aforementioned changes into the revised Generating Station Title V permit.

If you have any questions or comments, please feel free to contact either myself at 913-458-9062 or Bob Holmes at 913-458-2126.

Very truly yours,

BLACK & VEATCH

Kyle Lucas
Air Quality Specialist

Enclosure

cc: B. Gianazza – JEA
B. Holmes – B&V
File

Attachment 1

ISC Class II and Class I
Air Dispersion Modeling Report

INDUSTRIAL SOURCE COMPLEX
CLASS II AND CLASS I
AIR DISPERSION MODELING REPORT
FOR THE
GENERATING STATION

PREPARED BY
BLACK & VEATCH

MARCH 2004

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Appendices

1.0 Air Quality Impact Analysis

This Air Quality Impact Analysis (AQIA) is intended to support JEA's proposed fuel oil switch and increase in oil firing hours of operation for the simple cycle combustion turbine (SCCT) and the two combined cycle combustion turbines (CCCTs) at the Brandy Branch Generating Station facility (hereinafter referred to as the Proposed Project). Specifically, JEA proposes to permit an alternate operating scenario allowing for the use of natural gas with a higher sulfur content of 2.0 grains per 100 standard cubic feet (hereinafter referred to as 2.0 natural gas) and a cleaner, lower sulfur fuel oil (0.0065% sulfur) (hereinafter referred to as LSFO). This will allow greater operational flexibility for the Generating Station while meeting compliance requirements.

The following sections discuss the air dispersion modeling performed for the Prevention of Significant Deterioration (PSD) air quality impact analysis for those pollutants, which will have a Potential to Emit (PTE) greater than the PSD significant emission rate (i.e., NO_x, SO_2, CO, and PM_{10}). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), mutually agreed upon air dispersion modeling performed in support of Brandy Branch permits PSD-FL-267 and PSD-FL-310, as well as an air dispersion modeling protocol submitted to FDEP on behalf of JEA in a memorandum from Black & Veatch dated January 12, 2004.

1.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 02035) air dispersion model was used to predict maximum ground level concentrations associated with the Proposed Project emissions. The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to access pollutant concentrations from a wide variety of sources associated with an industrial source complex. In addition, ISCST3, unlike its predecessors, incorporates the COMPLEX1 dispersion algorithm for determining intermediate and complex terrain concentration impacts in accordance with EPA guidance.

1.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the ISCST3 model default options and input databases.

1.2.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, fuels (i.e., 2.0 natural gas and LSFO), and ambient temperatures. This was accomplished by representing each unit's operating load range (i.e., 50, 75, and 100 percent

loads) with a worst-case set of stack parameters and pollutant emission rates that were conservatively selected from vendor performance data to produce the worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping".

The worst-case representative stack parameters and emission rates for each load, fuel type, and ambient temperature considered in the analysis are presented in Tables 1-1, 1-2, and 1-3. It should be noted that the information for the modeling is based on the following:

- May 1999 SCCT application document and subsequent permit (Permit No. PSD-FL-267).
- December 2000 CCCT application document and subsequent permit (Permit No. PSD-FL-310).
- March 2003 Duct Burner administrative change submittal and subsequent amended permit summer 2003.
- Conversations with the fuel vendor and GE turbine manufacturer indicated that the LSFO will have no change to or effect the operation of the turbine or electrical generation, stack parameters (flows and temperatures), or pollutant emissions except for an SO2 reduction.

Spreadsheets used in determining the load based representative emissions and stack parameters from the aforementioned vendor performance data have been summarized and are included in Appendix A. In general, given the new fuel sulfur values discussed above, the proposed operating scenarios, and thus the modeling scenarios represented in this report, are as follows:

- All three combustion turbines can be operated on 2.0 natural gas as dictated by their current permits' operating conditions which allow the simple cycle combustion turbine to operate 4,750 hours per year and the combined cycle units to operate 8,760 hours per year each while firing natural gas.
- The simple cycle combustion turbine can be operated up to 8 hours per day while the combined cycle units can be operated up to 24 hours/day while firing the LSFO on a short-term basis. On a long-term basis, the units can be operated on the LSFO as dictated by the proposed permits' operating conditions which allow the simple cycle combustion turbine to operate 1,000 hours per year and the combined cycle units to operate 1,000 hours per year each while firing natural gas with the remained of the year on 2.0 natural gas.
- The simple cycle combustion turbine can be operated up to 24 hours/day while firing the LSFO the combined cycle units shall not be fired on any fuel for the same 24 hours.

1.2.2 Land Use Dispersion Coefficient Determination

The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site was classified as rural or urban using the Auer land use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the Generating Station's location, it was concluded that over 50 percent of the area surrounding the Generating Station is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

1.2.3 GEP Stack Height Determination

The Generating Station's buildings and structures were analyzed to determine their potential to influence the dispersion of stack emissions. EPA's Guideline for Determination of Good Engineering Practice Stack Height guidance document was followed in this evaluation. Structure dimensions and relative locations were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters.

1.2.4 Model Defaults

The following standard USEPA default regulatory modeling options were initialized in the ISCST3 air dispersion modeling:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

1.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the Generating Station was used. The rectangular grid network consists of 100 m spacing from the fenceline out to 1 km, 250 m spacing from 1 to 2.5 km, 500 m spacing from 2.5 to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing of 100 m intervals

Table 1-1
Representative (*Enveloped*) Stack Parameters and Pollutant Emissions [a] Used in ISCST3 Modeling Analysis
For Pollutants with Averaging Periods Less Than 24 Hours

Operating Scenario/Fuel	ISCST3 Source ID	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
							NO_x	SO_2 [d]	CO [e]	PM_{10}
2.0 natural gas [b]	Simple Cycle	100	27.43	5.49	45.04	855.93	N/A	1.44	6.55	N/A
	Combined Cycle 1	100	57.91	5.49	18.71	368.71	N/A	1.54	7.88	N/A
	Combined Cycle 2	100	57.91	5.49	18.71	368.71	N/A	1.54	7.88	N/A
	Simple Cycle	75	27.43	5.49	37.85	873.15	N/A	1.16	5.17	N/A
	Combined Cycle 1	75	57.91	5.49	15.27	363.15	N/A	1.23	5.44	N/A
	Combined Cycle 2	75	57.91	5.49	15.27	363.15	N/A	1.23	5.44	N/A
	Simple Cycle	50	27.43	5.49	32.42	899.82	N/A	0.92	4.28	N/A
	Combined Cycle 1	50	57.91	5.49	12.68	358.15	N/A	0.98	4.48	N/A
	Combined Cycle 2	50	57.91	5.49	12.68	358.15	N/A	0.98	4.48	N/A
LSFO [c]	Simple Cycle	100	27.43	5.49	46.27	848.71	N/A	1.71	8.69	N/A
	Combined Cycle 1	100	57.91	5.49	21.28	402.59	N/A	1.79	9.13	N/A
	Combined Cycle 2	100	57.91	5.49	21.28	402.59	N/A	1.79	9.13	N/A
	Simple Cycle	75	27.43	5.49	38.54	912.59	N/A	1.38	6.43	N/A
	Combined Cycle 1	75	57.91	5.49	16.70	397.04	N/A	1.45	6.78	N/A
	Combined Cycle 2	75	57.91	5.49	16.70	397.04	N/A	1.45	6.78	N/A
	Simple Cycle	50	27.43	5.49	33.06	922.04	N/A	1.08	9.32	N/A
	Combined Cycle 1	50	57.91	5.49	14.17	394.26	N/A	1.13	9.71	N/A
	Combined Cycle 2	50	57.91	5.49	14.17	394.26	N/A	1.13	9.71	N/A

N/A indicates that the particular pollutant does not have an averaging period less than 24 hours.

[a] The data used in the modeling analysis was based on the previous submittals referenced in Section 1.2.1 and summarized in spreadsheets included in Appendix A.

[b] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet.

[c] The sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[d] Values represent the emissions used in the SO_2 3-hour air dispersion modeling. These are the highest emission rates at each given load over all ambient temperatures (i.e., 95°F, 59°F, and 20°F).

[e] Values represent the emissions used in the CO 1 and 8-hour air dispersion modeling. These are the highest emission rates at each given load over all ambient temperatures (i.e., 95°F, 59°F, and 20°F).

Table 1-2
Representative (Enveloped) Stack Parameters and Pollutant Emissions [a] Used in ISCST3 Modeling Analysis
For Pollutants with Averaging Periods of 24 Hours

Operating Scenario/Fuel	ISCST3 Source ID	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
							NO_x	SO_2 [d]	CO	PM_{10} [e]
2.0 natural gas [b]	Simple Cycle	100	27.43	5.49	45.04	855.93	N/A	1.44	N/A	1.13
	Combined Cycle 1	100	57.91	5.49	18.71	368.71	N/A	1.54	N/A	1.30
	Combined Cycle 2	100	57.91	5.49	18.71	368.71	N/A	1.54	N/A	1.30
	Simple Cycle	75	27.43	5.49	37.85	873.15	N/A	1.16	N/A	1.13
	Combined Cycle 1	75	57.91	5.49	15.27	363.15	N/A	1.23	N/A	1.20
	Combined Cycle 2	75	57.91	5.49	15.27	363.15	N/A	1.23	N/A	1.20
	Simple Cycle	50	27.43	5.49	32.42	899.82	N/A	0.92	N/A	1.13
	Combined Cycle 1	50	57.91	5.49	12.68	358.15	N/A	0.98	N/A	1.20
	Combined Cycle 2	50	57.91	5.49	12.68	358.15	N/A	0.98	N/A	1.20
LSFO [c]	Simple Cycle [f]	100	27.43	5.49	46.27	848.71	N/A	0.57	N/A	0.71
	Combined Cycle 1	100	57.91	5.49	21.28	402.59	N/A	1.79	N/A	2.26
	Combined Cycle 2	100	57.91	5.49	21.28	402.59	N/A	1.79	N/A	2.26
	Simple Cycle [f]	75	27.43	5.49	38.54	912.59	N/A	0.46	N/A	0.71
	Combined Cycle 1	75	57.91	5.49	16.70	397.04	N/A	1.45	N/A	2.26
	Combined Cycle 2	75	57.91	5.49	16.70	397.04	N/A	1.45	N/A	2.26
	Simple Cycle [f]	50	27.43	5.49	33.06	922.04	N/A	0.36	N/A	0.71
	Combined Cycle 1	50	57.91	5.49	14.17	394.26	N/A	1.13	N/A	2.26
	Combined Cycle 2	50	57.91	5.49	14.17	394.26	N/A	1.13	N/A	2.26
	Simple Cycle [g]	100	27.43	5.49	46.27	848.71	N/A	1.71	N/A	2.14
	Simple Cycle [g]	75	27.43	5.49	38.54	912.59	N/A	1.38	N/A	2.14
	Simple Cycle [g]	50	27.43	5.49	33.06	922.04	N/A	1.08	N/A	2.14

N/A indicates that the particular pollutant does not have an averaging period less than 24 hours.

[a] The data used in the modeling analysis was based on the previous submittals referenced in Section 1.2.1 and summarized in spreadsheets included in Appendix A.

[b] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet.

[c] The sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[d] Values represent the emissions used in the SO_2 24-hour air dispersion modeling. These are the highest emission rates at each given load over all ambient temperatures (i.e., 95°F, 59°F, and 20°F).

[e] Values represent the emissions used in the PM_{10} 24-hour air dispersion modeling. These are the highest emission rates at each given load over all ambient temperatures (i.e., 95°F, 59°F, and 20°F).

[f] The simple cycle unit was limited to operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day.

[g] Additionally, the with the limitation of simple cycle operation on LSFO when the combined cycle units are also operating on LSFO, the simple cycle unit was separately modeled alone operating on fuel oil for the entire day (i.e., without the simultaneous operation of the combined cycle units on LSFO for 24 hours/day).

Table 1-3
Representative (Enveloped) Stack Parameters and Pollutant Emissions [a] Used in ISCST3 Modeling Analysis
For Pollutants with Annual Averaging Periods

Operating Scenario/Fuel	ISCST3 Source ID	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
							NO_x [c]	SO_2 [c]	CO	PM_{10} [c]
Annual Operation [b]	Simple Cycle	100	27.43	5.49	47.78	875.37	8.85	0.76	N/A	0.73
	Combined Cycle 1	100	57.91	5.49	20.15	368.71	4.29	1.50	N/A	1.34
	Combined Cycle 2	100	57.91	5.49	20.15	368.71	4.29	1.50	N/A	1.34
	Simple Cycle	75	27.43	5.49	39.54	888.15	7.09	0.61	N/A	0.73
	Combined Cycle 1	75	57.91	5.49	16.18	363.15	3.42	1.18	N/A	1.32
	Combined Cycle 2	75	57.91	5.49	16.18	363.15	3.42	1.18	N/A	1.32
	Simple Cycle	50	27.43	5.49	33.69	913.15	5.58	0.49	N/A	0.73
	Combined Cycle 1	50	57.91	5.49	13.23	358.15	2.73	0.95	N/A	1.32
	Combined Cycle 2	50	57.91	5.49	13..23	358.15	2.73	0.95	N/A	1.32

N/A indicates that the particular pollutant does not have an averaging period less than 24 hours.

[a] The data used in the modeling analysis was based on the previous submittals referenced in Section 1.2.1 and summarized in spreadsheets included in Appendix A.

[b] Annual operation assumes a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit.
Additionally, the sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[c] Values represent the emissions from the annual average ambient temperature cases of 59°F averaged for the respective hours of operation mentioned in footnote b.

was used along the Generating Station's fenceline, and a 100 m fine grid was used at the maximum impact receptors. Figure 1-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission sources and downwash structures. The flat terrain option was used for all receptor points.

1.2.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1984-1988) of surface and upper air meteorological data from Jacksonville, Florida and Waycross, Georgia, respectively, were used in the ISCST3 air dispersion modeling analysis. These meteorological data were downloaded from EPA's SCRAM web site and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

1.3 Model Results

In accordance with the submitted modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x, SO_2, CO, and PM_{10} for each applicable averaging period. Tables 1-4 through 1-11 present the results for the 5 year refined modeling period (1984-1988) for each pollutant and applicable averaging period. The underlined concentrations in each table represent the maximum modeled predicted impacts in each case. As the tables indicate, the Proposed Project's maximum predicted concentrations are less than the PSD Class II Significant Impact Levels (SILs) for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and NAAQS analyses) are required.

Additionally, the maximum predicted concentrations are less than the pre-construction monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements.

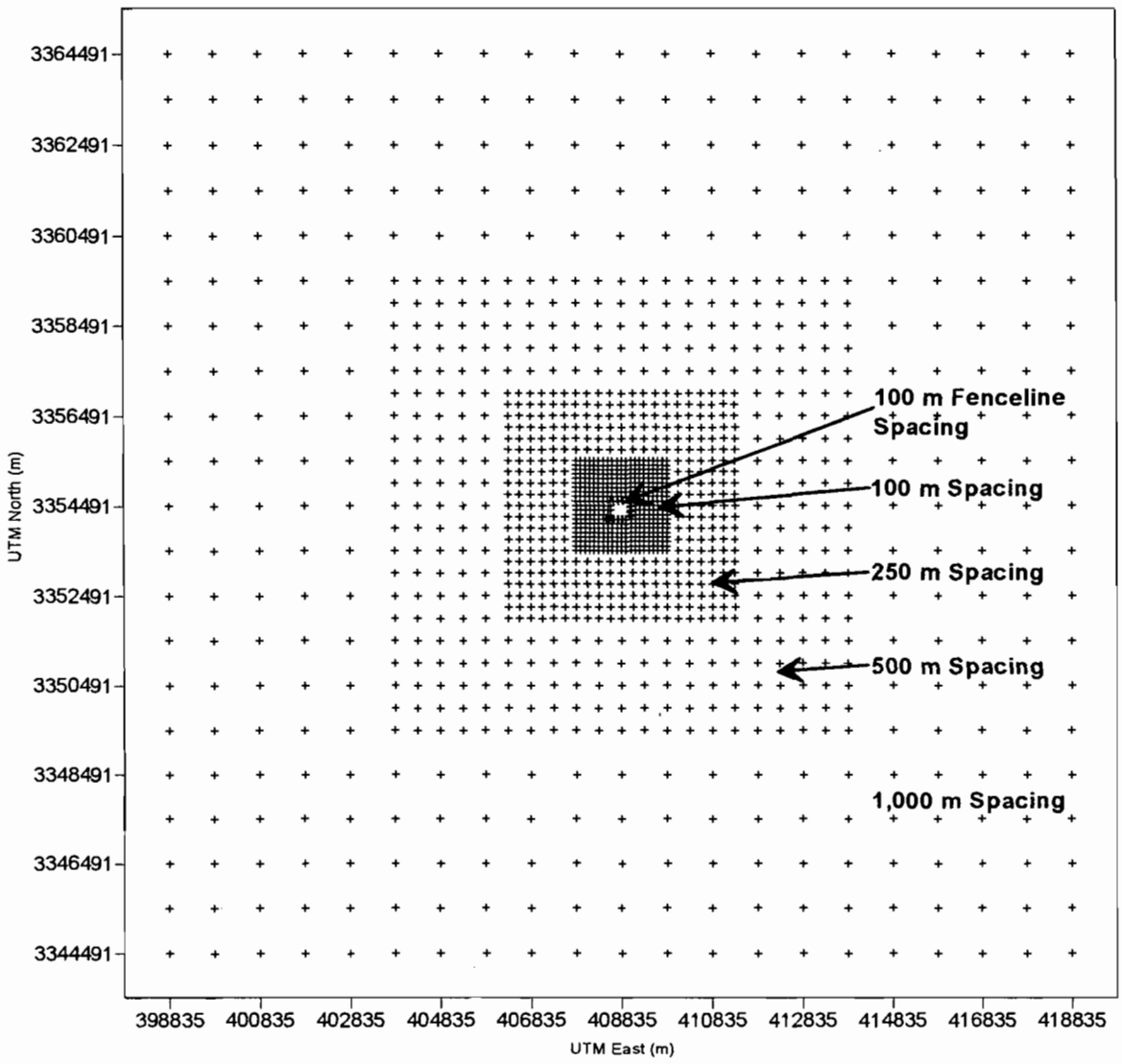

Figure 1-1
Class II Receptor Location Plot

Table 1-4
ISCST3 Model Predicted Maximum 1-hour Concentrations of CO

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	75.08	2,000	NO
		75	84.32	2,000	NO
		50	86.66	2,000	NO
	LSFO	100	85.98	2,000	NO
		75	98.94	2,000	NO
		50	179.04	2,000	NO
1985	2.0 natural gas	100	75.71	2,000	NO
		75	75.92	2,000	NO
		50	73.12	2,000	NO
	LSFO	100	90.98	2,000	NO
		75	90.99	2,000	NO
		50	154.20	2,000	NO
1986	2.0 natural gas	100	38.83	2,000	NO
		75	45.18	2,000	NO
		50	50.48	2,000	NO
	LSFO	100	39.73	2,000	NO
		75	51.45	2,000	NO
		50	99.98	2,000	NO
1987	2.0 natural gas	100	103.88	2,000	NO
		75	108.36	2,000	NO
		50	108.29	2,000	NO
	LSFO	100	117.59	2,000	NO
		75	126.43	2,000	NO
		50	222.19	2,000	NO
1988	2.0 natural gas	100	75.26	2,000	NO
		75	77.33	2,000	NO
		50	75.07	2,000	NO
	LSFO	100	90.66	2,000	NO
		75	92.50	2,000	NO
		50	157.87	2,000	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.
[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously.

Table 1-5
ISCST3 Model Predicted Maximum 8-hour Concentrations of CO

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	27.54	500	NO
		75	31.29	500	NO
		50	33.58	500	NO
	LSFO	100	28.71	500	NO
		75	35.12	500	NO
		50	66.27	500	NO
1985	2.0 natural gas	100	12.65	500	NO
		75	15.88	500	NO
		50	23.94	500	NO
	LSFO	100	15.16	500	NO
		75	16.51	500	NO
		50	43.35	500	NO
1986	2.0 natural gas	100	8.57	500	NO
		75	12.01	500	NO
		50	16.45	500	NO
	LSFO	100	7.37	500	NO
		75	12.25	500	NO
		50	30.18	500	NO
1987	2.0 natural gas	100	16.23	500	NO
		75	17.62	500	NO
		50	19.51	500	NO
	LSFO	100	17.27	500	NO
		75	19.68	500	NO
		50	38.08	500	NO
1988	2.0 natural gas	100	21.97	500	NO
		75	26.90	500	NO
		50	31.21	500	NO
	LSFO	100	21.38	500	NO
		75	29.21	500	NO
		50	59.92	500	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.
[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously.

Table 1-6
ISCST3 Model Predicted Maximum 3-hour Concentrations of SO_2

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	7.46	25	NO
		75	9.44	25	NO
		50	9.85	25	NO
	LSFO	100	7.38	25	NO
		75	10.24	25	NO
		50	10.61	25	NO
1985	2.0 natural gas	100	5.43	25	NO
		75	5.68	25	NO
		50	6.10	25	NO
	LSFO	100	5.96	25	NO
		75	6.51	25	NO
		50	6.08	25	NO
1986	2.0 natural gas	100	3.13	25	NO
		75	4.91	25	NO
		50	6.60	25	NO
	LSFO	100	2.90	25	NO
		75	4.71	25	NO
		50	6.43	25	NO
1987	2.0 natural gas	100	7.75	25	NO
		75	8.59	25	NO
		50	8.40	25	NO
	LSFO	100	8.05	25	NO
		75	9.44	25	NO
		50	9.11	25	NO
1988	2.0 natural gas	100	6.89	25	NO
		75	9.11	25	NO
		50	10.18	25	NO
	LSFO	100	6.43	25	NO
		75	9.47	25	NO
		50	10.55	25	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.
[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously.

Table 1-7
ISCST3 Model Predicted Maximum 24-hour Concentrations of SO_2

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	2.46	5	NO
		75	3.10	5	NO
		50	3.44	5	NO
	LSFO	100	1.38	5	NO
		75	1.84	5	NO
		50	1.92	5	NO
	LSFO	100 [c]	1.32	5	NO
		75 [c]	2.03	5	NO
		50 [c]	2.34	5	NO
1985	2.0 natural gas	100	1.47	5	NO
		75	2.27	5	NO
		50	3.17	5	NO
	LSFO	100	1.09	5	NO
		75	1.53	5	NO
		50	1.87	5	NO
	LSFO	100 [c]	0.84	5	NO
		75 [c]	0.99	5	NO
		50 [c]	1.64	5	NO
1986	2.0 natural gas	100	0.70	5	NO
		75	1.10	5	NO
		50	1.45	5	NO
	LSFO	100	0.49	5	NO
		75	0.71	5	NO
		50	0.83	5	NO
	LSFO	100 [c]	0.28	5	NO
		75 [c]	0.50	5	NO
		50 [c]	0.85	5	NO
1987	2.0 natural gas	100	1.66	5	NO
		75	1.95	5	NO
		50	2.15	5	NO
	LSFO	100	0.94	5	NO
		75	1.19	5	NO
		50	1.22	5	NO
	LSFO	100 [c]	0.93	5	NO
		75 [c]	1.26	5	NO
		50 [c]	1.44	5	NO
1988	2.0 natural gas	100	1.53	5	NO
		75	2.04	5	NO
		50	2.28	5	NO
	LSFO	100	0.89	5	NO
		75	1.19	5	NO
		50	1.25	5	NO
	LSFO	100 [c]	0.79	5	NO
		75 [c]	1.38	5	NO
		50 [c]	1.64	5	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously unless otherwise noted. The simple cycle unit was limited to operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day. No additional 2.0 natural gas was included for the simple cycle unit.

[c] These values represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units.

Table 1-8
ISCST3 Model Predicted Maximum 24-hour Concentrations of PM_{10}

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	2.00	5	NO
		75	3.02	5	NO
		50	4.22	5	NO
	LSFO	100	1.73	5	NO
		75	2.86	5	NO
		50	3.83	5	NO
	LSFO	100 [c]	1.65	5	NO
		75 [c]	3.14	5	NO
		50 [c]	4.65	5	NO
1985	2.0 natural gas	100	1.23	5	NO
		75	2.21	5	NO
		50	3.89	5	NO
	LSFO	100	1.37	5	NO
		75	2.37	5	NO
		50	3.72	5	NO
	LSFO	100 [c]	1.06	5	NO
		75 [c]	1.53	5	NO
		50 [c]	3.25	5	NO
1986	2.0 natural gas	100	0.58	5	NO
		75	1.07	5	NO
		50	1.78	5	NO
	LSFO	100	0.62	5	NO
		75	1.10	5	NO
		50	1.66	5	NO
	LSFO	100 [c]	0.35	5	NO
		75 [c]	0.78	5	NO
		50 [c]	1.69	5	NO
1987	2.0 natural gas	100	1.35	5	NO
		75	1.91	5	NO
		50	2.64	5	NO
	LSFO	100	1.19	5	NO
		75	1.84	5	NO
		50	2.43	5	NO
	LSFO	100 [c]	1.17	5	NO
		75 [c]	1.96	5	NO
		50 [c]	2.86	5	NO
1988	2.0 natural gas	100	1.25	5	NO
		75	1.99	5	NO
		50	2.80	5	NO
	LSFO	100	1.12	5	NO
		75	1.85	5	NO
		50	2.49	5	NO
	LSFO	100 [c]	0.99	5	NO
		75 [c]	2.14	5	NO
		50 [c]	3.26	5	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously unless otherwise noted. The simple cycle unit was limited to operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day. No additional 2.0 natural gas was included for the simple cycle unit.

[c] These values represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units.

Table 1-9
ISCST3 Model Predicted Maximum Annual [a] Concentrations of NO_x

Year	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	100	0.08	1	NO
	75	0.13	1	NO
	50	0.18	1	NO
1985	100	0.06	1	NO
	75	0.10	1	NO
	50	0.16	1	NO
1986	100	0.06	1	NO
	75	0.09	1	NO
	50	0.12	1	NO
1987	100	0.11	1	NO
	75	0.19	1	NO
	50	0.26	1	NO
1988	100	0.09	1	NO
	75	0.16	1	NO
	50	0.22	1	NO

[a] Annual concentrations are derived from a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit.
[b] Each load contains the simple cycle and two combined cycle units operating simultaneously.

Table 1-10
ISCST3 Model Predicted Maximum Annual [a] Concentrations of SO_2

Year	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	100	0.02	1	NO
	75	0.03	1	NO
	50	0.04	1	NO
1985	100	0.02	1	NO
	75	0.03	1	NO
	50	0.04	1	NO
1986	100	0.02	1	NO
	75	0.03	1	NO
	50	0.04	1	NO
1987	100	0.03	1	NO
	75	0.05	1	NO
	50	0.07	1	NO
1988	100	0.03	1	NO
	75	0.04	1	NO
	50	0.05	1	NO

[a] Annual concentrations are derived from combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit.
[b] Each load contains the simple cycle and two combined cycle units operating simultaneously.

Table 1-11
ISCST3 Model Predicted Maximum Annual [a] Concentrations of PM_{10}

Year	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class II Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	100	0.02	1	NO
	75	0.03	1	NO
	50	0.05	1	NO
1985	100	0.01	1	NO
	75	0.03	1	NO
	50	0.06	1	NO
1986	100	0.02	1	NO
	75	0.04	1	NO
	50	0.06	1	NO
1987	100	0.03	1	NO
	75	0.06	1	NO
	50	0.09	1	NO
1988	100	0.02	1	NO
	75	0.05	1	NO
	50	0.08	1	NO

[a] Annual concentrations are derived from a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit.
[b] Each load contains the simple cycle and two combined cycle units operating simultaneously.

2.0 Class I Area Impact Analyses

Class I areas are afforded special attention based on their value from a natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine their potential for deteriorating the particular properties that make these areas worthy of their Class I designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

As shown in Figure 2-1, the Generating Station is located approximately 34 km southeast of the Federal PSD Class I Okefenokee National Wildlife Refuge (ONWR). The area is designated as a mandatory Class I area, under the jurisdiction of the Fish and Wildlife Service as their Federal Land Manager (FLM). The FLM typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing the Proposed Project's impact on air the quality and visibility/regional haze.

The following sections discuss the Proposed Project's impacts on ground level impacts and visibility at those portions of the nearby Class I area that lie within 50 km from the Generating Station as that is the generally accepted limitation of the models used in these analyses. Those portions of the Class I area that lie beyond 50 km from the Generating Station were treated with a more advanced air dispersion model approved for distances beyond 50 km. Those analyses can be found in Attachment 2.

2.1 Ground-Level Impact Analysis

Air dispersion modeling was performed to determine the Proposed Project's maximum predicted impact at the Class I areas. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted impacts of NO_x, SO_2, and PM_{10} at receptors placed on that portion of the Class I area that lies within 50 km from the Generating Station. As presented in the most recent analyses submitted to the FDEP, over 1,110 receptors spaced every 500 m were used in the analysis. Figure 2-2 illustrates the receptors used in this Class I area analysis. The 5 year meteorological data set, model options, and operating scenarios used in the refined modeling analysis presented in Section 1, were also used in the Class I air quality impact analyses. This includes the source input parameters presented in Tables 1-1 through 1-3.

Tables 2-1 through 2-6 present the results of the Class I areas air dispersion modeling for each pollutant and applicable averaging period. The maximum predicted concentrations are presented for each year and compared with the Class I SILs. The Class I SILs were calculated as 4 percent of the PSD Class I increments. As the results in these tables indicate, the maximum predicted concentrations of all pollutants and averaging periods are less than the applicable Class I SILs for the Class I area. Therefore, under the PSD program, no further air quality impact analysis (i.e., PSD increment analysis) is required.

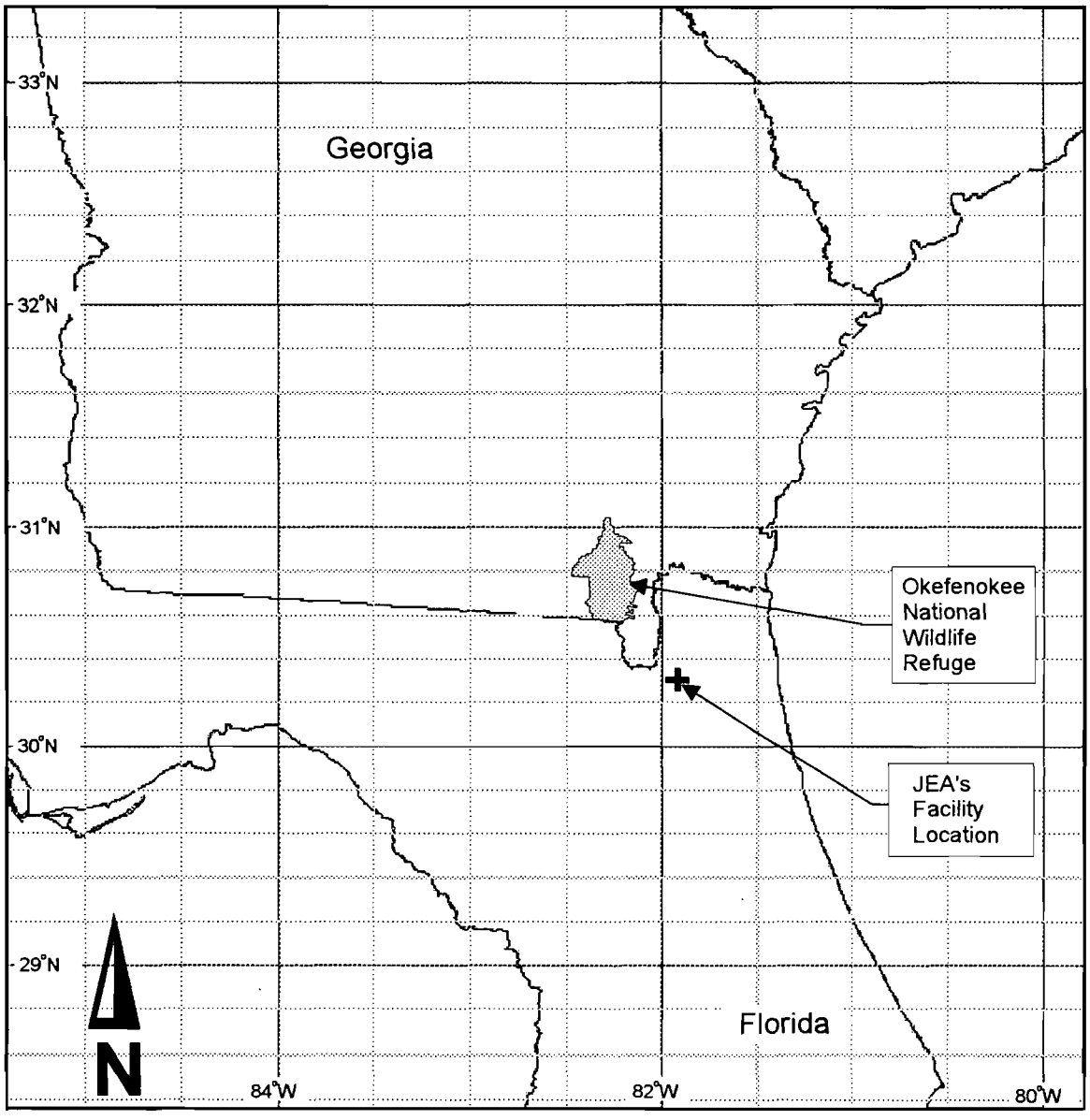

Figure 2-1
Generating Station Location With Respect To Okefenokee

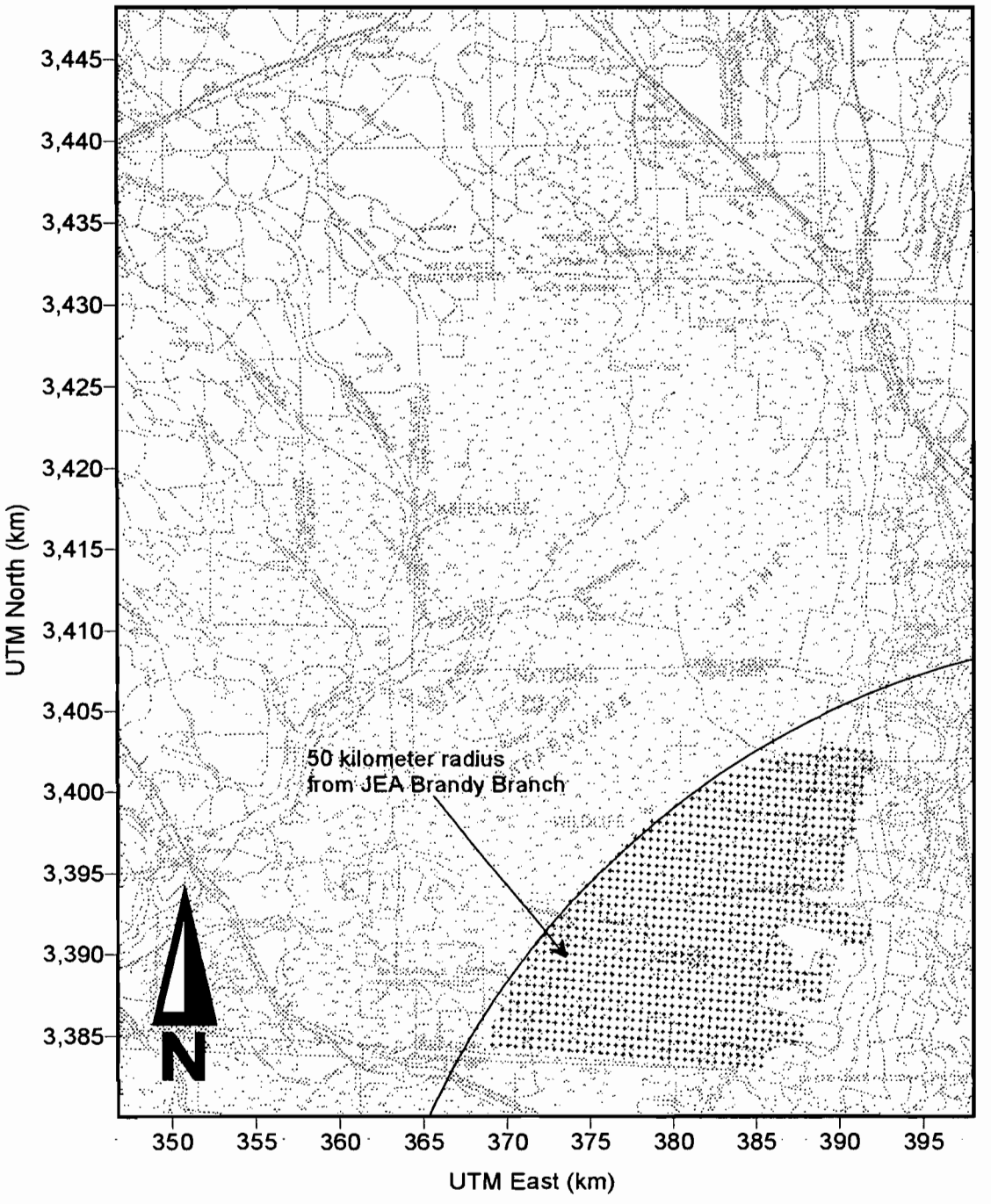

Figure 2-2
Okefenokee Receptors within 50 km

Table 2-1
ISCST3 Model Predicted Maximum Annual [a] Concentrations of NO_x

Year	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class I Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	100	0.02	0.1	NO
	75	0.02	0.1	NO
	50	0.01	0.1	NO
1985	100	0.01	0.1	NO
	75	0.01	0.1	NO
	50	0.01	0.1	NO
1986	100	0.02	0.1	NO
	75	0.01	0.1	NO
	50	0.01	0.1	NO
1987	100	0.02	0.1	NO
	75	0.02	0.1	NO
	50	0.01	0.1	NO
1988	100	0.02	0.1	NO
	75	0.02	0.1	NO
	50	0.02	0.1	NO

[a] Annual concentrations are derived from a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation and 1,000 hours of LSFO operation per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation and 1,000 hours of LSFO operation per year for each combined cycle unit.

[b] Each load contains the simple cycle and two combined cycle units operating simultaneously.

Table 2-2
ISCST3 Model Predicted Maximum Annual [a] Concentrations of SO_2

Year	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class I Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	100	0.005	0.08	NO
	75	0.005	0.08	NO
	50	0.004	0.08	NO
1985	100	0.004	0.08	NO
	75	0.004	0.08	NO
	50	0.003	0.08	NO
1986	100	0.004	0.08	NO
	75	0.004	0.08	NO
	50	0.003	0.08	NO
1987	100	0.005	0.08	NO
	75	0.004	0.08	NO
	50	0.004	0.08	NO
1988	100	0.006	0.08	NO
	75	0.005	0.08	NO
	50	0.005	0.08	NO

[a] Annual concentrations are derived from a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation and 1,000 hours of LSFO operation per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation and 1,000 hours of LSFO operation per year for each combined cycle unit.

[b] Each load contains the simple cycle and two combined cycle units operating simultaneously.

Table 2-3
ISCST3 Model Predicted Maximum Annual [a] Concentrations of PM_{10}

Year	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class I Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	100	0.005	0.16	NO
	75	0.005	0.16	NO
	50	0.006	0.16	NO
1985	100	0.004	0.16	NO
	75	0.004	0.16	NO
	50	0.004	0.16	NO
1986	100	0.004	0.16	NO
	75	0.004	0.16	NO
	50	0.005	0.16	NO
1987	100	0.004	0.16	NO
	75	0.005	0.16	NO
	50	0.005	0.16	NO
1988	100	0.006	0.16	NO
	75	0.006	0.16	NO
	50	0.007	0.16	NO

[a] Annual concentrations are derived from a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation and 1,000 hours of LSFO operation per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation and 1,000 hours of LSFO operation per year for each combined cycle unit.

[b] Each load contains the simple cycle and two combined cycle units operating simultaneously.

Table 2-4
ISCST3 Model Predicted Maximum 3-hour Concentrations of SO_2

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class I Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	0.32	1	NO
		75	0.30	1	NO
		50	0.28	1	NO
	LSFO	100	0.32	1	NO
		75	0.29	1	NO
		50	0.25	1	NO
1985	2.0 natural gas	100	0.38	1	NO
		75	0.33	1	NO
		50	0.28	1	NO
	LSFO	100	0.40	1	NO
		75	0.35	1	NO
		50	0.29	1	NO
1986	2.0 natural gas	100	0.47	1	NO
		75	0.41	1	NO
		50	0.34	1	NO
	LSFO	100	0.50	1	NO
		75	0.44	1	NO
		50	0.37	1	NO
1987	2.0 natural gas	100	0.42	1	NO
		75	0.36	1	NO
		50	0.31	1	NO
	LSFO	100	0.43	1	NO
		75	0.38	1	NO
		50	0.32	1	NO
1988	2.0 natural gas	100	0.38	1	NO
		75	0.33	1	NO
		50	0.28	1	NO
	LSFO	100	0.39	1	NO
		75	0.35	1	NO
		50	0.29	1	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously.

Table 2-5
ISCST3 Model Predicted Maximum 24-hour Concentrations of SO_2

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class I Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	0.10	0.2	NO
		75	0.09	0.2	NO
		50	0.08	0.2	NO
	LSFO	100	0.08	0.2	NO
		75	0.08	0.2	NO
		50	0.07	0.2	NO
	LSFO	100 [c]	0.02	0.2	NO
		75 [c]	0.02	0.2	NO
		50 [c]	0.02	0.2	NO
1985	2.0 natural gas	100	0.10	0.2	NO
		75	0.08	0.2	NO
		50	0.07	0.2	NO
	LSFO	100	0.07	0.2	NO
		75	0.06	0.2	NO
		50	0.07	0.2	NO
	LSFO	100 [c]	0.02	0.2	NO
		75 [c]	0.02	0.2	NO
		50 [c]	0.01	0.2	NO
1986	2.0 natural gas	100	0.16	0.2	NO
		75	0.14	0.2	NO
		50	0.12	0.2	NO
	LSFO	100	0.15	0.2	NO
		75	0.13	0.2	NO
		50	0.11	0.2	NO
	LSFO	100 [c]	0.04	0.2	NO
		75 [c]	0.04	0.2	NO
		50 [c]	0.03	0.2	NO
1987	2.0 natural gas	100	0.08	0.2	NO
		75	0.07	0.2	NO
		50	0.06	0.2	NO
	LSFO	100	0.07	0.2	NO
		75	0.06	0.2	NO
		50	0.05	0.2	NO
	LSFO	100 [c]	0.02	0.2	NO
		75 [c]	0.02	0.2	NO
		50 [c]	0.02	0.2	NO
1988	2.0 natural gas	100	0.11	0.2	NO
		75	0.10	0.2	NO
		50	0.09	0.2	NO
	LSFO	100	0.10	0.2	NO
		75	0.09	0.2	NO
		50	0.08	0.2	NO
	LSFO	100 [c]	0.02	0.2	NO
		75 [c]	0.02	0.2	NO
		50 [c]	0.02	0.2	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously unless otherwise noted. The simple cycle unit was limited to operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day.

[c] These values represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units.

Table 2-6
ISCST3 Model Predicted Maximum 24-hour Concentrations of PM_{10}

Year	Fuel [a]	Load [b]	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Class I Significant Impact Level ($\mu g/m^3$)	Exceed Threshold? (YES/NO)
1984	2.0 natural gas	100	0.08	0.32	NO
		75	0.09	0.32	NO
		50	0.09	0.32	NO
	LSFO	100	0.11	0.32	NO
		75	0.12	0.32	NO
		50	0.13	0.32	NO
	LSFO	100 [c]	0.03	0.32	NO
		75 [c]	0.03	0.32	NO
		50 [c]	0.03	0.32	NO
1985	2.0 natural gas	100	0.08	0.32	NO
		75	0.08	0.32	NO
		50	0.09	0.32	NO
	LSFO	100	0.09	0.32	NO
		75	0.10	0.32	NO
		50	0.13	0.32	NO
	LSFO	100 [c]	0.02	0.32	NO
		75 [c]	0.03	0.32	NO
		50 [c]	0.03	0.32	NO
1986	2.0 natural gas	100	0.14	0.32	NO
		75	0.14	0.32	NO
		50	0.15	0.32	NO
	LSFO	100	0.19	0.32	NO
		75	0.20	0.32	NO
		50	0.21	0.32	NO
	LSFO	100 [c]	0.05	0.32	NO
		75 [c]	0.06	0.32	NO
		50 [c]	0.07	0.32	NO
1987	2.0 natural gas	100	0.07	0.32	NO
		75	0.07	0.32	NO
		50	0.08	0.32	NO
	LSFO	100	0.08	0.32	NO
		75	0.10	0.32	NO
		50	0.11	0.32	NO
	LSFO	100 [c]	0.02	0.32	NO
		75 [c]	0.03	0.32	NO
		50 [c]	0.03	0.32	NO
1988	2.0 natural gas	100	0.09	0.32	NO
		75	0.10	0.32	NO
		50	0.11	0.32	NO
	LSFO	100	0.12	0.32	NO
		75	0.14	0.32	NO
		50	0.15	0.32	NO
	LSFO	100 [c]	0.02	0.32	NO
		75 [c]	0.03	0.32	NO
		50 [c]	0.03	0.32	NO

[a] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.
[b] Each load contains the simple cycle and the two combined cycle units operating simultaneously unless otherwise noted. The simple cycle unit was limited to operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day.
[c] These values represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units.

2.2 Visibility Analysis

The additional impact analysis requirements of a PSD permit application are concerned with visibility impairment within the Generating Station's impact area. The general components of a visibility impairment analysis include:

- Determine the visual quality of the area.
- Determine the potential for visibility impairment with a screening level assessment.
- If warranted, conduct a more in-depth analysis of the visibility impairment potential.

2.2.1 Visual Quality of the Area

The Generating Station is located in northeastern Florida, immediately surrounded by forest and grassland. The climate is characterized as nearly tropical with warm temperatures and abundant moisture. The high relative humidity and coastal influence generally result in moderate visibility with relatively low background visual ranges.

2.2.2 Visual Impairment Screening Assessment

A visibility impairment screening analysis was conducted in accordance with EPA's Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015, September 1988, hereinafter referred to as the Workbook) for the portion of the Class I area located less than 50 km from the Generating Station in order to provide a conservative indication of the perceptibility of plumes from the Proposed Project's emission sources. The only Federal PSD Class I Area within 50 km is the ONWR located approximately 34 km northwest of the Generating Station. It should be noted, a regional haze analysis was conducted for that portion of the Class I area located greater than 50 km from the Generating Station and is contained in a separate report.

The analysis was performed using the VISCREEN model. In accordance with Workbook visual screening procedures, the VISCREEN plume visual impact screening model was used with default worst-case Level-1 visual screening parameters using the maximum estimated emission rates of NO_x and PM_{10}.

In accordance with EPA procedures, the plume visual impact screening model (VISCREEN) was utilized with input and default parameters appropriately chosen for this geographical region. The criteria for evaluating whether there is significant visibility impairment is whether the plume from a source has the potential to be perceptible to untrained observers under reasonable worst-case conditions. The majority of input parameter values were not changed from the VISCREEN default values as specified in the Workbook. However, background visual range, stability class, and windspeed parameters

have been changed to values more representative of the specific region and operating conditions of the Proposed Project, thereby producing a more realistic analysis. The situation-specific modeled values are described below:

Emissions. The worst-case maximum hourly emissions of LSFO for NO_x and PM_{10} were used in the visibility analysis modeling. These values were obtained by first summing the NO_x emissions and then the PM_{10} emission from the simple cycle and two combined cycle units.

Distances. The geometry of the Generating Station and the Okefenokee Wilderness Area make the source-observer and minimum source distance 34 km and the maximum source distance 80 km.

Background Visual Range. A background visual range value which is considered representative of the area was based on a telephone conversation with Mr. Bud Rolofson at the Fish and Wildlife Service in Denver, Colorado on January 15, 1999. The background visual range is 65 km.

Stability Class and Windspeed. The VISCREEN stability class default value of 'F' and windspeed default value of 1.0 meter per second (m/s) were found not to be representative of the general climatological conditions of the area in the vicinity of the Generating Station. Therefore, stability class information contained in the five years (1984-1988) of meteorological data that were used in the ISCST3 air dispersion modeling were analyzed to determine a more representative stability class. A frequency distribution for Stability Classes 1 through 7 was performed for each season of each of the five years of meteorological data. The results of the analysis show that 'D' Class stability, or neutral stability, is most common stability class contained within the five years of meteorological data.

To establish a more representative wind speed, climatological data were reviewed for this area. Windspeed values of 7.9 miles per hour (mph) (3.53 m/s) were given in the Local Climatological Data Annual Summaries for 1996, Part IV - Southern Region published by the National Oceanic and Atmospheric Administration (NOAA) for Jacksonville, Florida. This windspeed value was determined to be more representative of the windspeeds in the Generating Station area than the VISCREEN default value of 1.0 m/s.

2.2.3 VISCREEN Results

Based on the results of this analysis, the Proposed Project's plume visual impact passes the Level-2 analysis specified by the Workbook for a CLASS I area. Potential visual impairment from the Proposed Project's plume will not cause a notable problem or be perceptible to untrained observers. Therefore, further analyses to quantify the extent of any reductions in visibility due to emissions from the Proposed Project are not warranted based on the results of the Level-2 visual impairment screening analysis. The VISCREEN results can be found in Appendix B.

Appendix A
Vendor Performance
and Emissions Summary Sheets

JEA - Brandy Branch

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Determination of Representative Emission and Stack Parameters and Potential to Emit Calculator

Simple Cycle Operation - Natural Gas

Load 100 percent — GE7FA

Case Name	Case 1	Case 2	Case 3
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	1144	1116	1081
Exit Velocity (ft/s)	147.76	156.75	164
Emissions (lb/h)			
NOX	71.20	79.20	84.80
CO	43.00	48.00	52.00
PM/PM10	9.00	9.00	9.00
SO2	9.70	10.70	11.40
VOC	2.60	2.80	3.00

Load 75 percent

Case Name	Case 4	Case 5	Case 6
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	1170	1139	1112
Exit Velocity (ft/s)	124.17	129.71	133.13
Emissions (lb/h)			
NOX	58.40	63.20	67.20
CO	36.00	39.00	41.00
PM/PM10	9.00	9.00	9.00
SO2	7.90	8.60	9.20
VOC	2.20	2.20	2.40

Load 50 percent

Case Name	Case 7	Case 8	Case 9
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	1200	1184	1160
Exit Velocity (ft/s)	106.35	110.53	112.68
Emissions (lb/h)			
NOX	46.40	50.40	52.80
CO	30.00	33.00	34.00
PM/PM10	9.00	9.00	9.00
SO2	6.40	6.90	7.30
VOC	1.80	1.80	2.00

Short-Term Enveloped Load Representative Emissions and Stack Parameters

Load 100 percent

Exit Temp (F)	1081.00	855.93	K
Exit Velocity (ft/s)	147.76	45.04	m/s
Emissions (lb/h)			
NOX	84.80	10.68	g/s
CO	52.00	6.55	g/s
PM/PM10	9.00	1.13	g/s
SO2	11.40	1.44	g/s
VOC	3.00	0.38	g/s

Load 75 percent

Exit Temp (F)	1112.00	873.15	K
Exit Velocity (ft/s)	124.17	37.85	m/s
Emissions (lb/h)			
NOX	67.20	8.47	g/s
CO	41.00	5.17	g/s
PM/PM10	9.00	1.13	g/s
SO2	9.20	1.16	g/s
VOC	2.40	0.30	g/s

Load 50 percent

Exit Temp (F)	1160.00	899.82	K
Exit Velocity (ft/s)	106.35	32.42	m/s
Emissions (lb/h)			
NOX	52.80	6.65	g/s
CO	34.00	4.28	g/s
PM/PM10	9.00	1.13	g/s
SO2	7.30	0.92	g/s
VOC	2.00	0.25	g/s

Annualized Enveloped Load Representative Emissions and Stack Parameters (59 Degrees)

Load 100 percent

Exit Temp (F)	1116.00	875.37	K
Exit Velocity (ft/s)	156.75	47.78	m/s
Emissions (lb/h)			
NOX	42.95	5.41	g/s
CO	26.03	3.28	g/s
PM/PM10	4.88	0.61	g/s
SO2	5.80	0.73	g/s
VOC	1.52	0.19	g/s

Load 75 percent

Exit Temp (F)	1139.00	888.15	K
Exit Velocity (ft/s)	129.71	39.54	m/s
Emissions (lb/h)			
NOX	34.27	4.32	g/s
CO	21.15	2.66	g/s
PM/PM10	4.88	0.61	g/s
SO2	4.66	0.59	g/s
VOC	1.19	0.15	g/s

Load 50 percent

Exit Temp (F)	1184.00	913.15	K
Exit Velocity (ft/s)	110.53	33.69	m/s
Emissions (lb/h)			
NOX	27.33	3.44	g/s
CO	17.89	2.25	g/s
PM/PM10	4.88	0.61	g/s
SO2	3.74	0.47	g/s
VOC	0.98	0.12	g/s

Simple Cycle Operation - Fuel Oil

Load 100 percent — GE7FA

Case Name	Case 10	Case 11	Case 12
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	1133	1098	1068
Exit Velocity (ft/s)	151.8	161.6	168.04
Emissions (lb/h)			
NOX	286.00	318.00	338.00
CO	59.00	65.00	69.00
PM/PM10	17.00	17.00	17.00
SO2	11.49	12.77	13.56
VOC	2.60	3.00	3.00

Load 75 percent — GE7FA

Case Name	Case 13	Case 14	Case 15
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	1200	1194	1183
Exit Velocity (ft/s)	126.43	131.67	135.15
Emissions (lb/h)			
NOX	232.00	256.00	271.00
CO	47.00	50.00	51.00
PM/PM10	17.00	17.00	17.00
SO2	9.40	10.36	10.98
VOC	2.20	2.20	2.40

Load 50 percent — GE7FA

Case Name	Case 16	Case 17	Case 18
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	1200	1200	1200
Exit Velocity (ft/s)	108.45	112.04	113.42
Emissions (lb/h)			
NOX	182.00	199.00	209.00
CO	74.00	63.00	57.00
PM/PM10	17.00	17.00	17.00
SO2	7.45	8.15	8.57
VOC	1.80	1.80	2.00

Short-Term Enveloped Load Representative Emissions and Stack Parameters

Load 100 percent

Exit Temp (F)	1068.00	848.71	K
Exit Velocity (ft/s)	151.80	46.27	m/s
Emissions (lb/h)			
NOX	338.00	42.59	g/s
CO	69.00	8.69	g/s
PM/PM10	17.00	2.14	g/s
SO2	13.56	1.71	g/s
VOC	3.00	0.38	g/s

Load 75 percent

Exit Temp (F)	1183.00	912.59	K
Exit Velocity (ft/s)	126.43	38.54	m/s
Emissions (lb/h)			
NOX	271.00	34.15	g/s
CO	51.00	6.43	g/s
PM/PM10	17.00	2.14	g/s
SO2	10.98	1.38	g/s
VOC	2.40	0.30	g/s

Load 50 percent

Exit Temp (F)	1200.00	922.04	K
Exit Velocity (ft/s)	108.45	33.06	m/s
Emissions (lb/h)			
NOX	209.00	26.33	g/s
CO	74.00	9.32	g/s
PM/PM10	17.00	2.14	g/s
SO2	8.57	1.08	g/s
VOC	2.00	0.25	g/s

Annualized Enveloped Load Representative Emissions and Stack Parameters (59 Degrees)

Load 100 percent

Exit Temp (F)	1098.00	865.37	K
Exit Velocity (ft/s)	161.60	49.26	m/s
Emissions (lb/h)			
NOX	36.30	4.57	g/s
CO	7.42	0.93	g/s
PM/PM10	1.94	0.24	g/s
SO2	1.46	0.18	g/s
VOC	0.34	0.04	g/s

Load 75 percent

Exit Temp (F)	1194.00	918.71	K
Exit Velocity (ft/s)	131.67	40.13	m/s
Emissions (lb/h)			
NOX	29.22	3.68	g/s
CO	5.71	0.72	g/s
PM/PM10	1.94	0.24	g/s
SO2	1.18	0.15	g/s
VOC	0.25	0.03	g/s

Load 50 percent

Exit Temp (F)	1200.00	922.04	K
Exit Velocity (ft/s)	112.04	34.15	m/s
Emissions (lb/h)			
NOX	22.72	2.86	g/s
CO	7.19	0.91	g/s
PM/PM10	1.94	0.24	g/s
SO2	0.93	0.12	g/s
VOC	0.21	0.03	g/s

Annual Operation

Total Annual Dual Fuel
Enveloped Load Representative
Emissions and Stack Parameters (59 Degrees)

Load 100 percent

Exit Temp (F)	1116.00	875.37	K
Exit Velocity (ft/s)	156.75	47.78	m/s
Emissions (lb/h)			
NOX	70.21	8.85	g/s
CO	27.97	3.52	g/s
PM/PM10	5.79	0.73	g/s
SO2	6.04	0.76	g/s
VOC	1.54	0.19	g/s

Load 75 percent

Exit Temp (F)	1139.00	888.15	K
Exit Velocity (ft/s)	129.71	39.54	m/s
Emissions (lb/h)			
NOX	56.28	7.09	g/s
CO	22.40	2.82	g/s
* PM/PM10	5.79	0.73	g/s
SO2	4.86	0.61	g/s
VOC	1.19	0.15	g/s

Load 50 percent

Exit Temp (F)	1184.00	913.15	K
Exit Velocity (ft/s)	110.53	33.69	m/s
Emissions (lb/h)			
NOX	44.29	5.58	g/s
CO	21.32	2.69	g/s
PM/PM10	5.79	0.73	g/s
SO2	3.88	0.49	g/s
VOC	0.98	0.12	g/s

SCCT Operating Parameters

Total Unit Operation	4750 h/yr
Natural Gas Operation	4750 h/yr
Lower Sulfur (0.0065%) Fuel Oil Operation	1000 h/yr

Notes

a Performance data from the May 1999 PSD simple cycle permit application.
b Based on information from JEA on 1/12/04 the lower sulfur fuel oil will not have any operational impact to the turbines except lower sulfur emissions.
c Annualized worst case emissions are from 100, 75, and 50% loads at annual average temperature of 59 F.
d Sulfur content assumed for the Natural Gas = 2.0 grains of sulfur/100 SCF (ratioed from 0.2 to 2.0 grains S/100 scf)
e Assumed 100% conversion of Sulfur to SO2 for natural gas.
f Sulfur content assumed for the lower sulfur distillate fuel oil = 0.0065% Sulfur (rationed from 0.05% S to 0.0065% S)
g PM/PM10 emissions reflect particulate emissions as denoted in the May 1999 PSD simple cycle permit application.
h VOC emissions represent 20% of the UHC emissions.
i NOx emissions reflect 12 ppm and not the 10.5 ppm as indicated in the air permit. Modeling will be performed at the original application's NOx emission rate.
j The stack parameters for the annual operating scenario for combined fuel (natural gas and fuel oil) reflect those parameters for the annualized natural gas fired case.

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Determination of Representative Emission and Stack Parameters and Potential to Emit Calculator

Combined Cycle Operation - Natural Gas

Load 100 percent — GE7FA

Case Name	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Ambient Temp (F)	95	95	95	95	59	59	20
Evap Cooler	NO	NO	YES	YES	NO	NO	NO
Duct Firing	YES	NO	NO	YES	NO	YES	NO
Exit Temp (F)	205	208	209	207	206	204	208
Exit Velocity (ft/s)	61.4	61.5	63.3	63.1	66.2	66.1	71.1
Emissions (lb/h)							
NOX	23.34	21.12	21.62	23.76	23.32	23.92	24.95
CO	62.57	45.53	46.47	61.33	50.29	54.87	54.26
PM/PM10	10.30	9.50	9.50	10.20	9.50	9.70	9.50
SO2	11.30	10.30	10.70	11.60	11.40	11.70	12.20
VOC	6.61	2.73	2.80	6.38	2.95	4.05	3.15

Load 75 percent

Case Name	Case 8	Case 10	Case 12
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	198	194	194
Exit Velocity (ft/s)	50.1	53.1	55.4
Emissions (lb/h)			
NOX	17.34	18.89	20.01
CO	37.67	41.05	43.16
PM/PM10	9.50	9.50	9.50
SO2	8.50	9.20	9.80
VOC	2.26	2.40	2.51

Load 50 percent

Case Name	Case 9	Case 11	Case 13
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	190	185	185
Exit Velocity (ft/s)	41.8	43.4	44.9
Emissions (lb/h)			
NOX	13.99	15.18	15.98
CO	31.79	34.12	35.53
PM/PM10	9.50	9.50	9.50
SO2	6.80	7.40	7.80
VOC	1.90	1.99	2.08

Short-Term Enveloped Load Representative Emissions and Stack Parameters

Load 100 percent

Exit Temp (F)	204.00	368.71	K
Exit Velocity (ft/s)	61.40	18.71	m/s
Emissions (lb/h)			
NOX	24.95	3.14	g/s
CO	62.57	7.88	g/s
PM/PM10	10.30	1.30	g/s
SO2	12.20	1.54	g/s
VOC	6.61	0.86	g/s

Load 75 percent

Exit Temp (F)	194.00	363.15	K
Exit Velocity (ft/s)	50.10	15.27	m/s
Emissions (lb/h)			
NOX	20.01	2.52	g/s
CO	43.16	5.44	g/s
PM/PM10	9.50	1.20	g/s
SO2	9.80	1.23	g/s
VOC	2.51	0.32	g/s

Load 50 percent

Exit Temp (F)	185.00	358.15	K
Exit Velocity (ft/s)	41.60	12.68	m/s
Emissions (lb/h)			
NOX	15.98	2.01	g/s
CO	35.53	4.48	g/s
PM/PM10	9.50	1.20	g/s
SO2	7.80	0.98	g/s
VOC	2.06	0.26	g/s

Annualized Enveloped Load Representative Emissions and Stack Parameters (59 Degrees)

Load 100 percent

Exit Temp (F)	204.00	368.71	K
Exit Velocity (ft/s)	66.10	20.15	m/s
Emissions (lb/h)			
NOX	23.92	3.01	g/s
CO	54.87	6.91	g/s
PM/PM10	9.70	1.22	g/s
SO2	11.70	1.47	g/s
VOC	4.05	0.51	g/s

Load 75 percent

Exit Temp (F)	194.00	363.15	K
Exit Velocity (ft/s)	53.10	16.18	m/s
Emissions (lb/h)			
NOX	18.89	2.38	g/s
CO	41.05	5.17	g/s
PM/PM10	9.50	1.20	g/s
SO2	9.20	1.16	g/s
VOC	2.40	0.30	g/s

Load 50 percent

Exit Temp (F)	185.00	358.15	K
Exit Velocity (ft/s)	43.40	13.23	m/s
Emissions (lb/h)			
NOX	15.18	1.91	g/s
CO	34.12	4.30	g/s
PM/PM10	9.50	1.20	g/s
SO2	7.40	0.93	g/s
VOC	1.99	0.25	g/s

Combined Cycle Operation - Fuel Oil

Load 100 percent — GE7FA

Case Name	Case 14	Case 15	Case 16	Case 17
Ambient Temp (F)	95	59	20	95
Evap Cooler	NO	NO	NO	YES
Duct Firing	NO	NO	NO	NO
Exit Temp (F)	272	265	265	274
Exit Velocity (ft/s)	69.8	75.3	79.7	71.7
Emissions (lb/h)				
NOX	101.23	112.41	119.37	104.53
CO	61.43	67.66	72.43	62.59
PM/PM10	17.90	17.90	17.90	17.90
SO2	12.05	13.39	14.22	12.45
VOC	7.05	7.68	8.14	7.24

Load 75 percent — GE7FA

Case Name	Case 18	Case 19	Case 20
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	259	255	255
Exit Velocity (ft/s)	54.8	56.9	56.9
Emissions (lb/h)			
NOX	82.81	91.21	96.85
CO	49.21	51.94	53.79
PM/PM10	17.90	17.90	17.90
SO2	9.86	10.88	11.51
VOC	5.64	5.69	6.09

Load 50 percent — GE7FA

Case Name	Case 21	Case 22	Case 23
Ambient Temp (F)	95	59	20
Evap Cooler	NO	NO	NO
Duct Firing	NO	NO	NO
Exit Temp (F)	252	250	250
Exit Velocity (ft/s)	46.5	47.9	48.6
Emissions (lb/h)			
NOX	65.62	71.78	75.46
CO	77.09	67.08	58.96
PM/PM10	17.90	17.90	17.90
SO2	7.61	8.55	8.99
VOC	4.64	4.99	5.06

Short-Term Enveloped Load Representative Emissions and Stack Parameters

Load 100 percent

Exit Temp (F)	265.00	402.59	K
Exit Velocity (ft/s)	69.80	21.28	m/s
Emissions (lb/h)			
NOX	119.37	15.04	g/s
CO	72.43	9.13	g/s
PM/PM10	17.90	2.26	g/s
SO2	14.22	1.79	g/s
VOC	8.14	1.03	g/s

Load 75 percent

Exit Temp (F)	255.00	397.04	K
Exit Velocity (ft/s)	54.80	16.70	m/s
Emissions (lb/h)			
NOX	96.85	12.18	g/s
CO	53.79	8.78	g/s
PM/PM10	17.90	2.26	g/s
SO2	11.51	1.45	g/s
VOC	6.09	0.77	g/s

Load 50 percent

Exit Temp (F)	250.00	394.26	K
Exit Velocity (ft/s)	46.50	14.17	m/s
Emissions (lb/h)			
NOX	75.46	9.51	g/s
CO	77.09	9.71	g/s
PM/PM10	17.90	2.26	g/s
SO2	8.99	1.13	g/s
VOC	5.06	0.64	g/s

Annualized Enveloped Load Representative Emissions and Stack Parameters (59 Degrees)

Load 100 percent

Exit Temp (F)	265.00	402.59	K
Exit Velocity (ft/s)	75.30	22.95	m/s
Emissions (lb/h)			
NOX	12.83	1.62	g/s
CO	7.75	0.98	g/s
PM/PM10	2.04	0.26	g/s
SO2	1.53	0.19	g/s
VOC	0.88	0.11	g/s

Load 75 percent

Exit Temp (F)	255.00	397.04	K
Exit Velocity (ft/s)	56.90	17.34	m/s
Emissions (lb/h)			
NOX	10.41	1.31	g/s
CO	5.93	0.75	g/s
PM/PM10	2.04	0.26	g/s
SO2	1.24	0.16	g/s
VOC	0.67	0.08	g/s

Load 50 percent

Exit Temp (F)	250.00	394.26	K
Exit Velocity (ft/s)	47.90	14.60	m/s
Emissions (lb/h)			
NOX	8.19	1.03	g/s
CO	7.66	0.96	g/s
PM/PM10	2.04	0.26	g/s
SO2	0.98	0.12	g/s
VOC	0.57	0.07	g/s

Annual Operation

Total Annual Dual Fuel
Enveloped Load Representative
Emissions and Stack Parameters (59 Degrees)

Load 100 percent

Exit Temp (F)	204.00	368.71	K
Exit Velocity (ft/s)	66.10	20.15	m/s
Emissions (lb/h)			
NOX	34.02	4.29	g/s
CO	56.35	7.10	g/s
PM/PM10	10.64	1.34	g/s
SO2	11.89	1.50	g/s
VOC	4.46	0.56	g/s

Load 75 percent

Exit Temp (F)	194.00	363.15	K
Exit Velocity (ft/s)	53.10	16.18	m/s
Emissions (lb/h)			
NOX	27.15	3.42	g/s
CO	42.29	5.33	g/s
PM/PM10	10.46	1.32	g/s
SO2	9.39	1.18	g/s
VOC	2.80	0.35	g/s

Load 50 percent

Exit Temp (F)	185.00	358.15	K
Exit Velocity (ft/s)	43.40	13.23	m/s
Emissions (lb/h)			
NOX	21.64	2.73	g/s
CO	37.88	4.77	g/s
PM/PM10	10.46	1.32	g/s
SO2	7.53	0.95	g/s
VOC	2.33	0.29	g/s

CCCT Operating Parameters

Natural Gas Operation	8760 h/yr
Lower Sulfur (0.0065%) Fuel Oil Operation	1000 h/yr

Notes

a Performance data from the December 2000 PSD combined cycle permit application & the modified pollutant emissions from the March 2003 duct burner modification submittal.
b *Based on information from JEA on 1/12/04 the lower sulfur fuel oil will not have any operational impact to the turbines except lower sulfur emissions.*
c Annualized worst case emissions are from 100, 75, and 50% loads at annual average temperature of 59 F.
d Sulfur content assumed for the Natural Gas = 2.0 grains of sulfur/100 SCF (ratioed from 0.2 to 2.0 grains S/100 scf)
e Assumed 100% conversion of Sulfur to SO2 for natural gas.
f Sulfur content assumed for the lower sulfur distillate fuel oil = 0.0065% Sulfur (rationed from 0.05% S to 0.0065% S)
g PM/PM10 emissions (as particulate) reflect front half catch excluding the effect of SO2 oxidation & SCR catalyst.
h The stack parameters for the annual operating scenario for combined fuel (natural gas and fuel oil) reflect those parameters for the annualized natural gas fired case.

Appendix B
VISCREEN Output

Visual Effects Screening Analysis for
Source: JEA BB
Class I Area: Oke

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	53.00	LB /HR
NOx (as NO2)	577.00	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

PARTICLE CHARACTERISTICS

	Density	Diameter
Primary Part.	2.5	6
Soot	2.0	1
Sulfate	1.5	4

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	34.00 km
Min. Source-Class I Distance:	34.00 km
Max. Source-Class I Distance:	80.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	4
Wind Speed:	3.53 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	140.	45.4	29.	2.08	.764	.05	-.001
SKY	140.	140.	45.4	29.	2.00	.316	.05	-.005
TERRAIN	10.	84.	34.0	84.	2.87	.288	.06	.003
TERRAIN	140.	84.	34.0	84.	2.00	.101	.06	.001

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	1.477	.05	.012
SKY	140.	0.	1.0	168.	2.00	.308	.05	-.014
TERRAIN	10.	0.	1.0	168.	2.00	1.716	.05	.022
TERRAIN	140.	0.	1.0	168.	2.00	.469	.05	.019

Attachment 2

CALPUFF Class I
Air Dispersion Modeling Report

CALPUFF CLASS I
AIR DISPERSION MODELING REPORT
FOR THE
BRANDY BRANCH FACILITY

PREPARED BY
BLACK & VEATCH

MARCH 2004

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1.0 Introduction

This Air Quality Impact Analysis (AQIA) is intended to support JEA's proposed fuel oil switch and increase in oil firing hours of operation for the simple cycle combustion turbine (SCCT) and the two combined cycle combustion turbines (CCCTs) at the Brandy Branch Generating Station facility (hereinafter referred to as the Proposed Project). Specifically, JEA proposes to permit an alternate operating scenario allowing for the use of natural gas with a higher sulfur content of 2.0 grains per 100 standard cubic feet (hereinafter referred to as 2.0 natural gas) and a cleaner, lower sulfur fuel oil (0.0065% sulfur) (hereinafter referred to as LSFO). This will allow greater operational flexibility for the Generating Station while meeting compliance requirements. The air dispersion modeling analysis was conducted in accordance with mutually agreed upon air dispersion modeling performed in support of Brandy Branch permits PSD-FL-267 and PSD-FL-310, as well as an air dispersion modeling protocol submitted to FDEP on behalf of JEA in a memorandum from Black & Veatch dated January 12, 2004.

As part of the air impact evaluation for the proposed revision to the Brandy Branch Generating Station, analyses of The Proposed Project's effect on the Okefenokee National Wildlife Refuge (ONWR) were performed. The ONWR is a Prevention of Significant Deterioration (PSD) Class I area located in south-east Georgia approximately 34 km north-northwest of the Generating Station. The analyses presented in this document were performed on that portion of the ONWR that lies greater than 50 km from the Generating Station. Analyses covering the portion of the ONWR that lies between 34 and 50 km from the Generating Station site are covered under a separate document and are included in Attachment 1. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze, deposition, and Class I Significant Impact Levels (SILs). Figure 1-1 presents the location of the Generating Station with respect to the ONWR.

The methodology of the refined CALPUFF analysis closely followed those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998, the Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) report dated December 2000 where appropriate for model option selections. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, the air modeling approach to assess impacts at ONWR, and the air quality impact results.

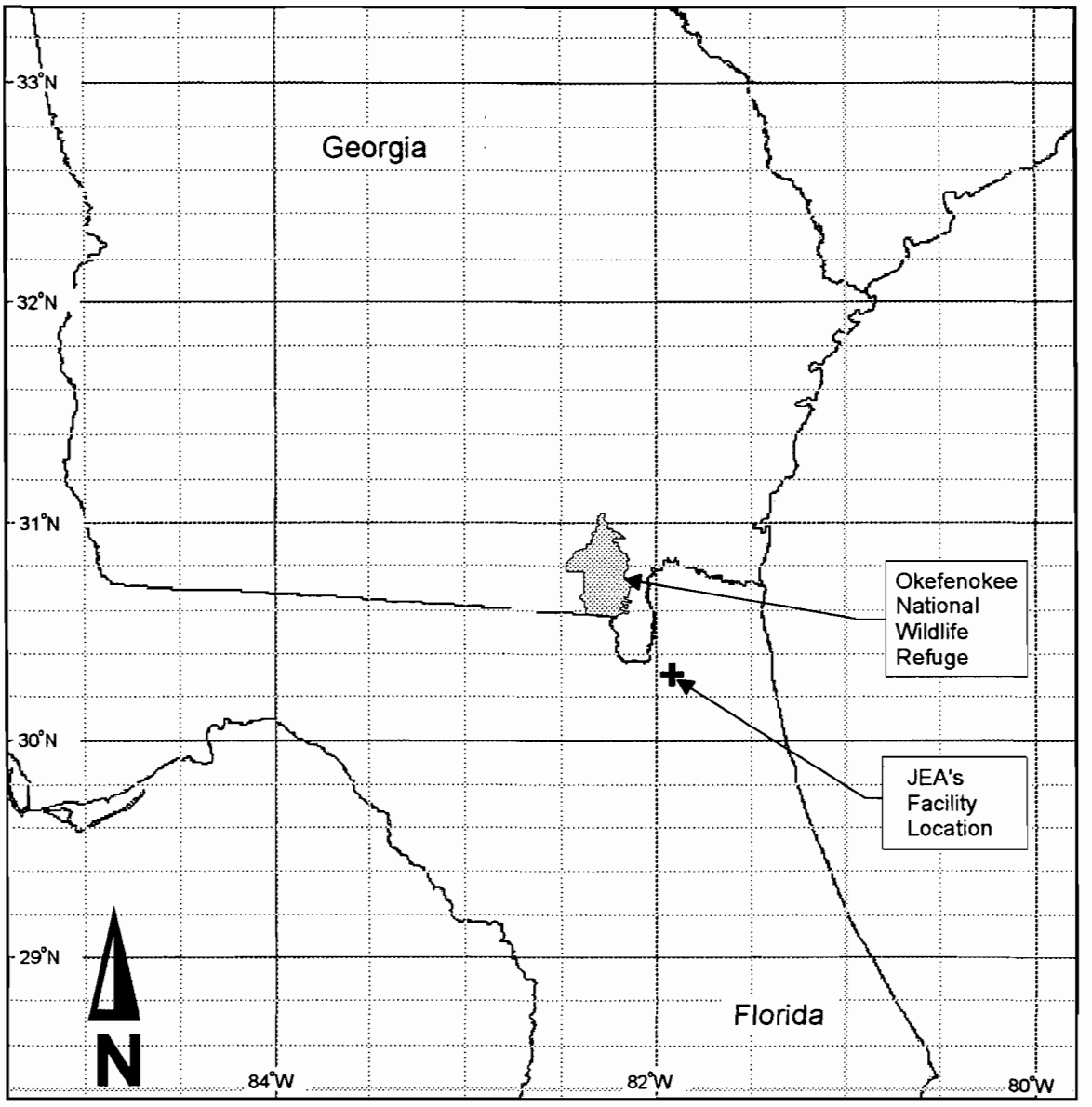


Figure 1-1
Generating Station Location With Respect To Okefenokee

2.0 Model Selection and Inputs

2.1 Model Selection

The California Puff (CALPUFF, Version 5.711, Level 030625) air modeling system was used to model the Proposed Project and assess the AQRVs at ONWR. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range (i.e., greater than 50 km) transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET will be input to CALPUFF to assess pollutant specific impacts.

2.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 2-1 were used for the modeling analyses.

2.3 Building Wake Effects

The CALPUFF analysis included the Generating Station's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

2.4 Receptor Locations

The CALPUFF analysis used an array of discrete receptors for ONWR, which were created and distributed by the NPS for standardized use in Class I analyses. Specifically, the array consists of 420 receptors spaced approximately every 1,750 meters, which cover the extent of the ONWR that lies beyond 50 km from the Generating Station. Terrain throughout the ONWR is included in the same NPS- provided receptor file. Only those receptors in the NPS file that lie beyond 50 km from the facility will be used in these

Table 2-1 CALPUFF Model Settings	
Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional plume rise, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour change as processed by CALPOST. Deposition: Highest predicted annual total sulfur and nitrogen values in deposition units. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Monthly Ammonia: 0.5 ppb; Monthly background ozone was obtained from the Duval Co. monitor and was based on a review of the available values averaged for each month. Additionally, hourly background ozone values from the Duval Co. monitor were assessed for inclusion into the CALPUFF modeling.

analyses. Figure 2-1 illustrates the receptors used in the CALPUFF Class I area air dispersion modeling analysis.

2.5 Meteorological Data Processing

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.53, Level 030709) were used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data used and processed in the CALMET model.

2.5.1 CALMET Settings

The CALMET settings, including horizontal and vertical grid coverage and resolution of prognostic mesoscale meteorological data, were chosen to adequately characterize the area within the CALMET domain.

2.5.2 Modeling Domain

The size of the domain used for the modeling was based on the distances needed to cover the area from the Generating Station to the receptors at the ONWR with at least an 80-km buffer zone in each direction. The modeling analysis was performed in the UTM coordinate system. A rectangular modeling domain extending 325 km in the east-west (x) direction and 250 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 29.25 N degrees latitude and 84 W degrees longitude. The grid resolution for the domain was 5 km. A grid spacing of 5 km yields 65 grid cells in the x-direction and 50 grid cells in the y-direction. Figure 2-2 illustrates the size and location of the modeling domain.

2.5.3 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological (MM) data sets of prognostic wind fields, or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and are used to populate the modeling domain with meteorological data. The analysis used 1990 MM4 (generation 4), 1992 MM5 (generation 5), and 1996 MM5 mesoscale meteorological data sets to initialize the CALMET wind fields for each modeled year. The three years of MM data were obtained from a NPS database provided to Black & Veatch.

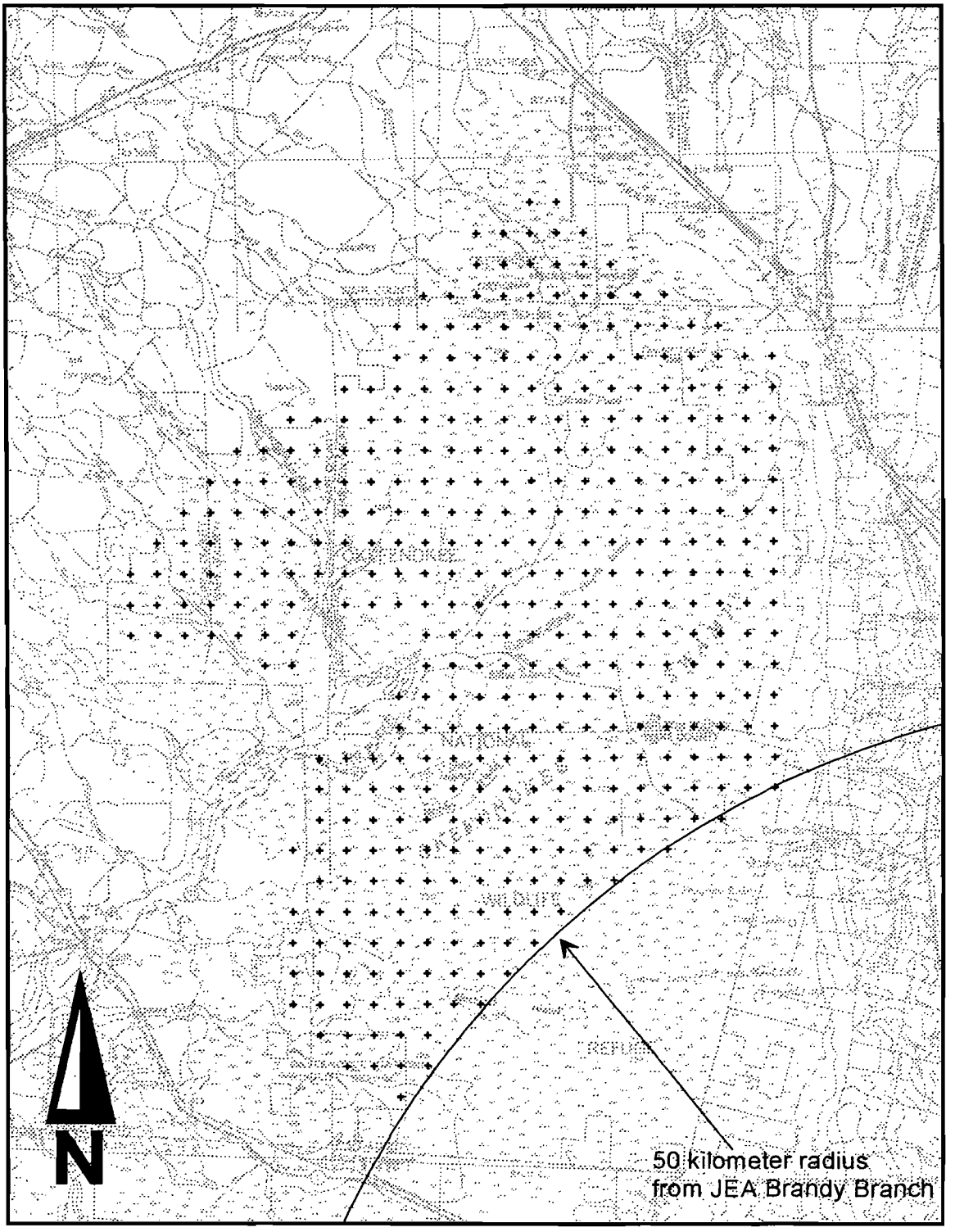


Figure 2-1
Okefenokee CALPUFF Receptors

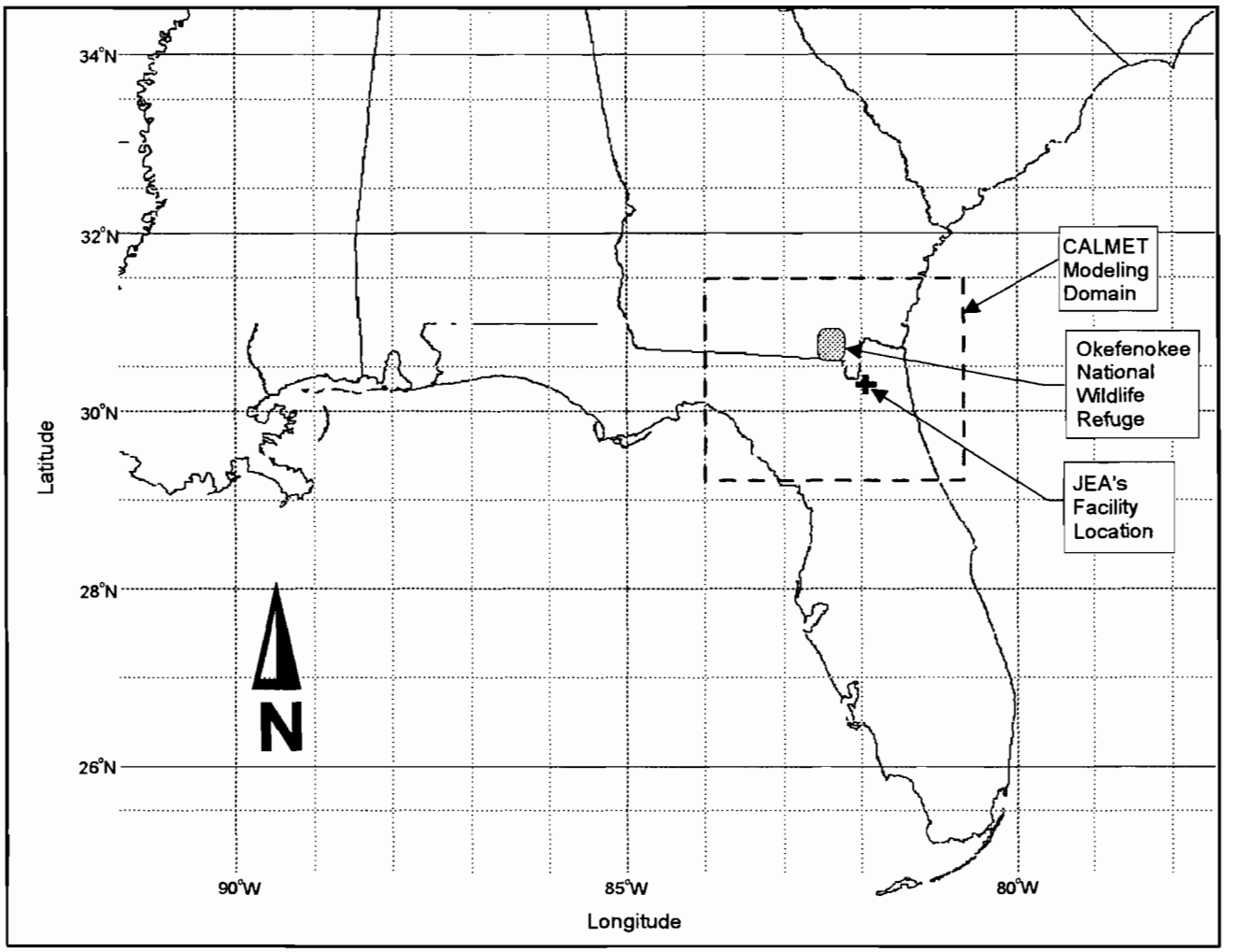


Figure 2-2
Modeling Domain

The extraction program accompanying the data was used to obtain the appropriate MM data points to cover the modeling domain. The 1990 MM4 and 1992 MM5 data have a horizontal spacing, or resolution, of 80 km. The 1996 MM5 data has a resolution of 36 km. The meteorological observations contained with the MM data sets are assumed to be of sufficient density, both temporally and spatially, to make the need for discrete meteorological station observation unnecessary. Thus, CALMET was run with the No Observations mode developed in the latest version available from the model developer, Earth Tech.

2.5.4 Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data were extracted for the modeling domain grid using the CALMET preprocessor program TERREL. Land-use data, based on annual averaged values, were also obtained from the USGS. Land-use values for the domain grid were extracted with the preprocessor programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once preprocessed, all of the land-use parameters were combined with the terrain information in a processor called MAKEGEO. This processor produces one GEO.DAT file for input to CALMET.

2.6 Proposed Project Emissions

The maximum pound per hour emission rates at 100% load and the average annual temperature of 59°F were used for the pollutants modeled with CALPUFF. Those pollutants include NO_x, SO_2, and PM_{10}. Tables 2-2 through 2-4 present the emissions and stack parameters used in the CALPUFF modeling analyses. The representative stack parameters and emission rates for each fuel type considered in the analysis are presented in Tables 2-2, 2-3, and 2-4. It should be noted that the information for the modeling is based on the following:

- May 1999 SCCT application document and subsequent permit (Permit No. PSD-FL-267).
- December 2000 CCCT application document and subsequent permit (Permit No. PSD-FL-310).
- March 2003 Duct Burner administrative change submittal and subsequent amended permit summer 2003.

- Conversations with the fuel vendor and GE turbine manufacturer indicated that the LSFO will have no change to or effect the operation of the turbine or electrical generation, stack parameters (flows and temperatures), or pollutant emissions except for an SO2 reduction.

Spreadsheets used in determining the load based representative emissions and stack parameters from the aforementioned vendor performance data have been summarized and are included in Appendix A of Attachment 1. In general, given the new fuel sulfur values discussed above, the proposed operating scenarios, and thus the modeling scenarios represented in this report, are as follows:

- All three combustion turbines can be operated on 2.0 natural gas as dictated by their current permits' operating conditions which allow the simple cycle combustion turbine to operate 4,750 hours per year and the combined cycle units to operate 8,760 hours per year each while firing natural gas.
- The simple cycle combustion turbine can be operated up to 8 hours per day while the combined cycle units can be operated up to 24 hours/day while firing the LSFO on a short-term basis. On a long-term basis, the units can be operated on the LSFO as dictated by the proposed permits' operating conditions which allow the simple cycle combustion turbine to operate 1,000 hours per year and the combined cycle units to operate 1,000 hours per year each while firing natural gas with the remained of the year on 2.0 natural gas.
- The simple cycle combustion turbine can be operated up to 24 hours/day while firing the LSFO the combined cycle units shall not be fired on any fuel for the same 24 hours.

Table 2-2
Stack Parameters and Pollutant Emissions [a] Used in CALPUFF Modeling Analysis
For Pollutants with Averaging Periods Less Than 24 Hours

Fuel	ISCST3 Source ID	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)		
						NO_x	SO_2 [d]	PM_{10}
2.0 Natural Gas [b]	Simple Cycle	27.43	5.49	47.78	875.37	N/A	1.35	N/A
	Combined Cycle 1	57.91	5.49	20.15	368.71	N/A	1.47	N/A
	Combined Cycle 2	57.91	5.49	20.15	368.71	N/A	1.47	N/A
LSFO [c]	Simple Cycle	27.43	5.49	49.26	865.37	N/A	1.61	N/A
	Combined Cycle 1	57.91	5.49	22.95	402.59	N/A	1.69	N/A
	Combined Cycle 2	57.91	5.49	22.95	402.59	N/A	1.69	N/A

N/A indicates that the particular pollutant does not have an averaging period less than 24 hours.
[a] The data used in the modeling analysis was based on the previous submittals referenced in Section 2.6 and summarized in spreadsheets included in Appendix A of Attachment 1.
[b] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet.
[c] The sulfur content of the LSFO in the modeling was assumed to be 0.0065%.
[d] Values represent the emissions used in the SO_2 3-hour air dispersion modeling. These are the highest emission rates at 100% load 59°F ambient temperature.

Table 2-3
Representative (Enveloped) Stack Parameters and Pollutant Emissions [a] Used in the CALPUFF Modeling Analysis
For Pollutants with Averaging Periods of 24 Hours

Fuel	ISCST3 Source ID	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)		
						NO_x [d]	SO_2 [d]	PM_{10} [d]
2.0 Natural Gas [b]	Simple Cycle	27.43	5.49	47.78	875.37	9.98	1.35	1.13
	Combined Cycle 1	57.91	5.49	20.15	368.71	3.01	1.47	1.22
	Combined Cycle 2	57.91	5.49	20.15	368.71	3.01	1.47	1.22
LSFO [c]	Simple Cycle [e]	27.43	5.49	49.26	865.37	13.36	0.54	0.71
	Combined Cycle 1	57.91	5.49	22.95	402.59	14.16	1.69	2.26
	Combined Cycle 2	57.91	5.49	22.95	402.59	14.16	1.69	2.26
	Simple Cycle [f]	27.43	5.49	49.26	865.37	40.07	1.61	2.14

[a] The data used in the modeling analysis was based on the previous submittals referenced in Section 2.6 and summarized in spreadsheets included in Appendix A of Attachment 1.
[b] The sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet.
[c] The sulfur content of the LSFO in the modeling was assumed to be 0.0065%.
[d] Values represent the emissions used in the NO_x, SO_2, and PM_{10} 24-hour air dispersion modeling. These are the highest emission rates at 100% load 59°F ambient temperature. While NO_x does not directly have a 24-hour averaging period for Class I SILs, the value presented above was used in the regional haze portion of the analysis which is a daily AQRV.
[e] The simple cycle unit was limited to operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for 24 hours/day.
[f] Additionally, the with the limitation on LSFO simple cycle operation when the combined cycle units are also operating on LSFO, the simple cycle unit was separately modeled alone operating on fuel oil for the entire day (i.e., without the simultaneous operation of the combined cycle units on LSFO).

Table 2-4

Representative (Enveloped) Stack Parameters and Pollutant Emissions [a] Used in the CALPUFF Modeling Analysis For Pollutants with Annual Averaging Periods

Operating Scenario/Fuel	ISCST3 Source ID	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)		
						NO_x [c]	SO_2 [c]	PM_{10} [c]
Annual Operation [b]	Simple Cycle	27.43	5.49	47.78	875.37	8.85	0.76	0.73
	Combined Cycle 1	57.91	5.49	20.15	368.71	4.29	1.50	1.34
	Combined Cycle 2	57.91	5.49	20.15	368.71	4.29	1.50	1.34

[a] The data used in the modeling analysis was based on the previous submittals referenced in Section 2.6 and summarized in spreadsheets included in Appendix A of Attachment 1.

[b] Annual operation assumes a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit.
Additionally, the sulfur content of the 2.0 natural gas in the modeling was assumed to be 2 grains of sulfur per 100 standard cubic feet and the sulfur content of the LSFO in the modeling was assumed to be 0.0065%.

[c] Values represent the emissions from the 100% load, annual average ambient temperature cases of 59°F averaged for the respective hours of operation on 2.0 natural gas and fuel oil mentioned in footnote a. These values were used in the annual SIL modeling for each pollutant, as well as the annual total nitrogen and total sulfur deposition analysis.

3.0 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the ONWR, including regional haze, deposition, and Class I SILs.

3.1 Regional Haze Analysis

A regional haze analysis was performed for the ONWR for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

3.1.1 Visibility

Visibility is an AQRV for the ONWR. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because portions of the ONWR lie beyond 50 km from the Generating Station, the change in visibility is analyzed as regional haze at those locations of the ONWR. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm^{-1}) = 3912 / vr(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a change in b_{extb}, or; percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extsb}) \times 100$$

3.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the ONWR. The background visual range, or constituents thereof, for the ONWR was obtained from the Phase I FLAG Report, December 2000. The average relative humidity factor for each day was computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each relative humidity can be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) were then be used to determine the average relative humidity factor for that day (24-hour period). All of this is accomplished with the use of the CALPOST post-processor.

3.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis closely followed the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (EPA, 12/98) where appropriate. Table 3-1 summarizes the IWAQM Phase II recommendations. The methodology in Table 3-1 was used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to

Table 3-1 Outline of IWAQM Refined Modeling Analyses Recommendations *	
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS provided the modeling receptors.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition 3. Define background values for ozone and ammonia for area
Processing	Use highest predicted 24-hr SO_4, PM_{10} and NO_3 values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of the CALPOST post-processor.

* *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).

post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection was made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze was calculated using method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. Based on recent correspondence with staff of the NPS, the relative humidity was capped at 95 percent. A supplementary analysis was performed with the relative humidity capped at 98 percent for informational purposes only. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Calculation

Refined impacts were calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:

   $(NH_4)_2SO_4$ ($\mu g/m3$) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4

   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375

   Convert the NO_3 impact to NH_4NO_3 by the following formula:

   NH_4NO_3 ($\mu g/m3$) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3

   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

   b_{exts} = 3 x NH_4NO_3 x f(RH) + 3 x $(NH_4)_2SO_4$ x f(RH) + 1 x PM_{10}
4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:

   b_{extb} = 3.912 / Visual range (km)
5. Compute the change in extinction coefficients:

   in terms of deciviews:

   $$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

   in terms of percent change of visibility:

   $$\Delta\% = (b_{exts} / b_{extsb}) \times 100$$

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the Proposed Project's emissions were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5. As illustrated in Table 3-2, the regional haze results are less than the 5% change in extinction threshold and as such, no further analysis is necessary.

Table 3-2
Regional Haze Results [a]

Fuel	Modeled Year	Change in Extinction [b] (%)	Recommended Threshold (%)
2.0 Natural Gas [c]	1990	0.77	5
	1992	1.46	5
	1996	1.66	5
LSFO [d]	1990	2.08	5
	1992	4.73	5
	1996	3.36	5
LSFO [e]	1990	1.46	5
	1992	2.46	5
	1996	2.94	5

[a] The results represent a relative humidity cap value of 95%. Additionally, the relative humidity was capped at 98% for informational purposes only. The results indicated only 3 values of the recommended 5 percent threshold over all three years modeled with the largest value being only 5.68%.

[b] Change in extinction was compared against the natural conditions presented in the FLAG 2000 document.

[c] Results represent all three combustion turbines operating on 2.0 natural gas for 24 hours/day.

[d] Results represent the simple cycle unit operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for 24 hours/day.

[e] Results represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units. This modeling demonstrates that while the simple cycle unit can operate on a limited basis (i.e., 8 hours/day) with the combined cycle units while firing LSFO, the simple cycle unit can also operate the full day on fuel oil when operated alone (i.e., without the combined cycle units).

3.2 Deposition Analyses

Deposition analyses was performed for the ONWR for both total sulfur and total nitrogen. The analyses closely followed those procedures and methodologies set forth in the IWAQM Phase II Report. Specifically, deposition analyses was performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 2.0 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

Table 3-3 presents the results of the deposition analysis for each of the three modeling years. As illustrated in the table, the deposition results are less than the 0.01 Deposition Analysis Threshold (DAT) and as such, no further analysis is necessary.

3.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) onto to the ONWR were calculated for NO_x, SO_2, and PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis were compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Tables 3-4 through 3-6 present the results of the Class I analysis for each of the three modeling years repectively. As illustrated in the table, there are no violations of the Class I SILs and as such, no further analysis is necessary.

Table 3-3
Deposition Results

Fuel	Modeled Year	Total Nitrogen Deposition [a] (kg/ha/yr)	Total Sulfur Deposition [b] (kg/ha/yr)	Deposition Analysis Threshold [c]
2.0 Natural Gas [d]	1990	0.003	0.004	0.01
	1992	0.003	0.003	0.01
	1996	0.003	0.003	0.01
LSFO [e]	1990	0.004	0.004	0.01
	1992	0.003	0.003	0.01
	1996	0.004	0.003	0.01

[a] Includes both wet and dry deposition with SO_4, NO_x, HNO_3, and NO_3 contributing to the nitrogen mass.

[b] Includes both wet and dry deposition with SO_2 and SO_4 contributing sulfur mass.

[c] For all areas East of the Mississippi River.

[d] As deposition is an annual AQRV, results represent all three combustion turbines operating on 2.0 natural gas for the entire year with no daily restrictions on operation. This is conservative as the simple cycle unit is restricted to 4,750 hours of operation per year regardless of fuel.

[e] As deposition is an annual AQRV, results represent all combustion units operating on a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit.

Table 3-4
1990 Significant Impact Level Modeling Results

Fuel	Modeled Year	Pollutant and Averaging Period	Modeled Impact ($\mu g/m^3$)	Significant Impact Level [a] ($\mu g/m^3$)	Exceed SIL?
2.0 Natural Gas [b]	1990	NO_x – Annual	0.004	0.10	NO
		PM_{10} – Annual	0.002	0.16	NO
		PM_{10} – 24-hour	0.040	0.32	NO
		SO_2 – Annual	0.002	0.08	NO
		SO_2 – 24-hour	0.040	0.20	NO
		SO_2 – 3-hour	0.150	1.0	NO
LSFO [c]	1990	NO_x – Annual	0.005	0.10	NO
		PM_{10} – Annual	0.002	0.16	NO
		PM_{10} – 24-hour	0.050	0.32	NO
		SO_2 – Annual	0.002	0.08	NO
		SO_2 – 24-hour	0.040	0.20	NO
		SO_2 – 3-hour	0.150	1.0	NO
LSFO [d]	1990	NO_x – Annual	N/A	0.10	NO
		PM_{10} – Annual	N/A	0.16	NO
		PM_{10} – 24-hour	0.020	0.32	NO
		SO_2 – Annual	N/A	0.08	NO
		SO_2 – 24-hour	0.010	0.20	NO
		SO_2 – 3-hour	N/A	1.0	NO

N/A indicates that the particular averaging period is not applicable to the operating scenario.

[a] Class I Significant Impact Levels are calculated as 4% of the PSD Class I Increment values.

[b] Results represent all three combustion turbines operating on 2.0 natural gas simultaneously for the entire year with no daily restrictions on operation. This is conservative as the simple cycle unit is restricted to 4,750 hours of operation per year regardless of fuel.

[c] The annual results represent all combustion units operating on a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit. The 24-hour results represent the simple cycle unit operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day. The 3-hour results represent all three combustion turbines operating simultaneously on LSFO.

[d] Results represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units. This modeling demonstrates that while the simple cycle unit can operate on a limited basis (i.e., 8 hours/day) with the combined cycle units while firing LSFO, the simple cycle unit can also operate the full day on fuel oil when operated alone (i.e., without the combined cycle units). Unrestricted annual and 3-hour modeling is already represented in the LSFO entry footnoted as "c" above.

Table 3-5
1992 Significant Impact Level Modeling Results

Fuel	Modeled Year	Pollutant and Averaging Period	Modeled Impact ($\mu g/m^3$)	Significant Impact Level [a] ($\mu g/m^3$)	Exceed SIL?
2.0 Natural Gas [b]	1992	NO_x – Annual	0.004	0.10	NO
		PM_{10} – Annual	0.002	0.16	NO
		PM_{10} – 24-hour	0.050	0.32	NO
		SO_2 – Annual	0.002	0.08	NO
		SO_2 – 24-hour	0.060	0.20	NO
		SO_2 – 3-hour	0.170	1.0	NO
LSFO [c]	1992	NO_x – Annual	0.005	0.10	NO
		PM_{10} – Annual	0.002	0.16	NO
		PM_{10} – 24-hour	0.070	0.32	NO
		SO_2 – Annual	0.002	0.08	NO
		SO_2 – 24-hour	0.060	0.20	NO
		SO_2 – 3-hour	0.170	1.0	NO
LSFO [d]	1992	NO_x – Annual	N/A	0.10	NO
		PM_{10} – Annual	N/A	0.16	NO
		PM_{10} – 24-hour	0.020	0.32	NO
		SO_2 – Annual	N/A	0.08	NO
		SO_2 – 24-hour	0.020	0.20	NO
		SO_2 – 3-hour	N/A	1.0	NO

N/A indicates that the particular averaging period is not applicable to the operating scenario.

[a] Class I Significant Impact Levels are calculated as 4% of the PSD Class I Increment values.

[b] Results represent all three combustion turbines operating on 2.0 natural gas simultaneously for the entire year with no daily restrictions on operation. This is conservative as the simple cycle unit is restricted to 4,750 hours of operation per year regardless of fuel.

[c] The annual results represent all combustion units operating on a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit. The 24-hour results represent the simple cycle unit operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day. The 3-hour results represent all three combustion turbines operating simultaneously on LSFO.

[d] Results represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units. This modeling demonstrates that while the simple cycle unit can operate on a limited basis (i.e., 8 hours/day) with the combined cycle units while firing LSFO, the simple cycle unit can also operate the full day on fuel oil when operated alone (i.e., without the combined cycle units). Unrestricted annual and 3-hour modeling is already represented in the LSFO entry footnoted as "c" above.

Table 3-6
1996 Significant Impact Level Modeling Results

Fuel	Modeled Year	Pollutant and Averaging Period	Modeled Impact ($\mu g/m^3$)	Significant Impact Level [a] ($\mu g/m^3$)	Exceed SIL?
2.0 Natural Gas [B]	1996	NO_x – Annual	0.006	0.10	NO
		PM_{10} – Annual	0.003	0.16	NO
		PM_{10} – 24-hour	0.040	0.32	NO
		SO_2 – Annual	0.003	0.08	NO
		SO_2 – 24-hour	0.050	0.20	NO
		SO_2 – 3-hour	0.200	1.0	NO
LSFO [c]	1996	NO_x – Annual	0.007	0.10	NO
		PM_{10} – Annual	0.003	0.16	NO
		PM_{10} – 24-hour	0.060	0.32	NO
		SO_2 – Annual	0.003	0.08	NO
		SO_2 – 24-hour	0.040	0.20	NO
		SO_2 – 3-hour	0.210	1.0	NO
LSFO [d]	1996	NO_x – Annual	N/A	0.10	NO
		PM_{10} – Annual	N/A	0.16	NO
		PM_{10} – 24-hour	0.020	0.32	NO
		SO_2 – Annual	N/A	0.08	NO
		SO_2 – 24-hour	0.010	0.20	NO
		SO_2 – 3-hour	N/A	1.0	NO

N/A indicates that the particular averaging period is not applicable to the operating scenario.

[a] Class I Significant Impact Levels are calculated as 4% of the PSD Class I Increment values.

[b] Results represent all three combustion turbines operating on 2.0 natural gas simultaneously for the entire year with no daily restrictions on operation. This is conservative as the simple cycle unit is restricted to 4,750 hours of operation per year regardless of fuel.

[c] The annual results represent all combustion units operating on a combination of 2.0 natural gas and LSFO operation based on the proposed permit limits of 4,750 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) per year for the simple cycle unit and 8,760 hours of 2.0 natural gas operation (of which 1,000 of those hours can be on LSFO) operation per year for each combined cycle unit. The 24-hour results represent the simple cycle unit operating 8 hours/day on LSFO when the combined cycle units are also operating on LSFO for the entire day. The 3-hour results represent all three combustion turbines operating simultaneously on LSFO.

[d] Results represent the simple cycle unit operating 24 hours/day on LSFO without the simultaneous operation of the combined cycle units. This modeling demonstrates that while the simple cycle unit can operate on a limited basis (i.e., 8 hours/day) with the combined cycle units while firing LSFO, the simple cycle unit can also operate the full day on fuel oil when operated alone (i.e., without the combined cycle units). Unrestricted annual and 3-hour modeling is already represented in the LSFO entry footnoted as "c" above.

Attachment 3

Title V Forms

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: JEA	
2. Site Name: Brandy Branch Generating Station	
3. Facility Identification Number: 0310485	
4. Facility Location...: Street Address or Other Locator: JEA Brandy Branch Generating Station City: Baldwin City County: Duval Zip Code: 32234	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: N. Bert Gianazza, P.E.
2. Application Contact Mailing Address... Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202-3139
3. Application Contact Telephone Numbers... Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Application Contact Email Address: giannb@jea.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☐ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.
☐ Title V air operation permit revision.
☐ Title V air operation permit renewal.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☒ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☒ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This application is for permitting of an alternate operating scenario of use of a lower sulfur fuel oil (0.0065% sulfur, by weight) in Unit 1, Unit 2 and Unit 3. In conjunction with permitting a lower sulfur fuel oil, which will result in reduced hourly SO_2 emission rates when firing fuel oil, this application seeks to relax current permit limits on the firing of fuel oil in the aforementioned emission units. This application is also for the incorporation of these new changes and changes covered by Construction Permit No. PSD-FL-310 into a revision of Title V operation permit No. 0310485-005-AV. As required by §62-213.420(1)(a).4, F.A.C., this application includes a compliance schedule and methodology in Attachment G. Hereinafter, pipeline quality natural gas with a maximum sulfur content of 2 grains per 100 standard cubic foot will be referred to as 2.0 natural gas. Also, hereinafter reference to No. 2 distillate fuel oil, as the facility is currently permitted to use, is typically referred to as simply fuel oil or 0.05% sulfur fuel oil. However, in some circumstances the use of the term fuel oil is used to refer to both 0.05% sulfur fuel oil and the ultra low sulfur fuel oil (0.0065% sulfur), such as where emission estimate information is given in Form F1 (except in reference to SO_2 emissions), as emissions of pollutants other than SO_2 are expected to be the same regardless of whether 0.05% sulfur fuel oil or the lower sulfur fuel oil is used.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	Unit 1 – 170 MW Simple Cycle Combustion Turbine		
002	Unit 2 – 170 MW Combined Cycle Combustion Turbine with Supplemental Firing		
003	Unit 3 - 170 MW Combined Cycle Combustion Turbine with Supplemental Firing		
007	Mechanical Draft Cooling Tower		

Application Processing Fee

Check one: ☐ Attached - Amount: $_____ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name :
   Mr. James M. Chansler, P.E., D.P.A., Vice President, Operations and Maintenance
2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: JEA
   Street Address: 21 West Church Street
   City: Jacksonville State: FL Zip Code: 32202
3. Owner/Authorized Representative Telephone Numbers...
   Telephone: (904) 665-4433 ext. Fax: (904) 665-7990
4. Owner/Authorized Representative Email Address:
5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.

James M. Chansler

Signature

3-9-04

Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
   Mr. James M. Chansler, P.E., D.P.A., Vice President, Operations and Maintenance

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☒ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: JEA
   Street Address: 21 West Church Street
   City: Jacksonville State: Florida Zip Code: 32202

4. Application Responsible Official Telephone Numbers...
   Telephone: (904) 665-4433 ext. Fax: (904) 665-7990

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

James M. Chansler — 3.9.04

Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: N. Bert Gianazza
   Registration Number: 38640
2. Professional Engineer Mailing Address...
   Organization/Firm: JEA
   Street Address: 21 West Church Street
   City: Jacksonville State: FL Zip Code: 32202
3. Professional Engineer Telephone Numbers...
   Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Professional Engineer Email Address: giannb@jea.com
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☒, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☒, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature 3/9/04
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 408.81 North (km) 3354.38		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 30/19/14 Longitude (DD/MM/SS) 81/56/55	
3. Governmental Facility Code: 4	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: N. Bert Gianazza, P.E. – Environmental Services
2. Facility Contact Mailing Address... Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202
3. Facility Contact Telephone Numbers: Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Facility Contact Email Address: giannb@jea.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	A	N
CO	A	N
VOC	B	N
SO2	A	Y
PM	A	N
PM10	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap
SO2	N	Units 2 and 3			

7. Facility-Wide or Multi-Unit Emissions Cap Comment:
576 combined hours of fuel oil firing for the two combined cycle combustion turbines (Units 2 and 3) per consecutive 12-month period while firing 0.05% sulfur, by weight, fuel oil. Proposed 2,000 combined hours of fuel oil firing for the two combined cycle combustion turbines (Units 2 and 3) per consecutive 12-month period while firing lower sulfur fuel oil (0.0065% sulfur, by weight).

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. A ☐ Previously Submitted, Date:
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. B ☐ Previously Submitted, Date:
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. C ☐ Previously Submitted, Date:

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   ☐ Attached, Document ID: _____ ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification:
   ☒ Attached, Document ID: Attach. D
3. Rule Applicability Analysis:
   ☒ Attached, Document ID: Attach. E
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):
   ☐ Attached, Document ID: _____ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.):
   ☐ Attached, Document ID: _____ ☒ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.):
   ☐ Attached, Document ID: _____ ☒ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.):
   ☐ Attached, Document ID: _____ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.):
   ☐ Attached, Document ID: _____ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.):
   ☐ Attached, Document ID: _____ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):
    ☐ Attached, Document ID: _____ ☒ Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):
   ☐ Attached, Document ID: ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only):
   ☐ Attached, Document ID:_____ ☒ Not Applicable (revision application)

2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought):
   ☒ Attached, Document ID:Attach. F
   ☐ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan (Required for all initial/revision/renewal applications):
   ☒ Attached, Document ID:Attach. G
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only):
   ☐ Attached, Document ID:_____
   ☐ Equipment/Activities On site but Not Required to be Individually Listed
   ☒ Not Applicable

5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) :
   ☐ Attached, Document ID:_____ ☒ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   ☒ Attached, Document ID:Attach. H ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [1] of [4]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Unit 1 – 170 MW Simple Cycle Combustion Turbine

3. Emissions Unit Identification Number: 001

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A		4-20-2001	49	☒ Yes ☐ No

9. Package Unit:
Manufacturer: General Electric Model Number: GE PG7241 FA

10. Generator Nameplate Rating: 170 MW

11. Emissions Unit Comment: This emission unit is a GE PG7241 FA combustion turbine. Unless otherwise noted, Unit information throughout the application is based on baseload, ISO conditions (59°F). This application seeks to change Title V Operation Permit No. 0310485-005-AV to include an additional operating segment consisting of firing lower sulfur fuel oil (0.0065% sulfur) in this emissions unit. With this application it is requested that the annual allowable hours of operation with the lower sulfur fuel oil be set at 1,000 hours per year along with a daily restriction of 8 hours per day on days in which the lower sulfur fuel oil is fired in a combined cycle unit (Unit No. 2 and Unit No. 3). No daily restriction is requested (Unit No. 1 is allowed to operate 24 hours on either 2.0 natural gas or the lower sulfur fuel oil) on days in which Unit No. 2 and Unit No. 3 do not fire lower sulfur fuel oil. Existing permit conditions pertaining to operation with the 0.05% sulfur distillate oil and/or 2.0 natural gas should remain in the permit and will be applicable during operational periods in which the 0.05% sulfur distillate oil is used.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Low NOx Burner Technology (two-stage combustor): For 2.0 natural gas firing the use of dry low NOx burner technology to control NOx emissions.

   Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing

2. Control Device or Method Code(s): 25 (2.0 natural gas firing), 28 (fuel oil firing)

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate:			
3. Maximum Heat Input Rate: 1,935 million Btu/hr (LHV)			
4. Maximum Incineration Rate:	pounds/hr tons/day		
5. Requested Maximum Operating Schedule:			
	2.0 natural gas firing	24 hours/day 52 weeks/year	7 days/week 4,750 hours/year
	Fuel oil firing	16 hours/day 52 weeks/year	7 days/week 750 hours/year
	Lower sulfur fuel oil firing	24 hours/day 52 weeks/year	7 days/week 1,000 hours/year

6. Operating Capacity/Schedule Comment:
The maximum heat input (mmBtu/hr) given in Permit No. 0310485-005-AV, based on the lower heating value (LHV) of each fuel, at ambient conditions of 59°F temperature, 60% relative humidity, 100% load and 14.7 psi pressure, are as follows:
2.0 natural gas firing: 1,623
Fuel oil firing: 1,822
These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. The heat input rates are included in the permit only for purposes of determining capacity during performance tests. Continuous compliance with these rates is not required. The maximum projected heat input rates are with operation at an ambient temperature of 20°F and are as follows.
2.0 natural gas firing @ 20F, 100% load = 1,736 (LHV)
Fuel oil firing @20F, 100% load = 1,935 (LHV)
It is suggested that Unit No.1 be limited to a total of 8 hours of operation on either 2.0 natural gas or the lower sulfur fuel oil on days when the lower sulfur fuel oil is fired in either Unit No. 2 or Unit No. 3. On days in which the lower sulfur fuel oil is not fired in either Unit No. 2 or Unit No. 3 there should be no daily restriction on operation of Unit No. 1, i.e. Unit No. 1 will be allowed to operate 24 hours on either 2.0 natural gas or lower sulfur fuel oil. This 24 hour per day scenario is reflected in Field 5 above.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Item No. 23 on Plot Plan	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Single stack		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 90 feet	7. Exit Diameter: 18.0 feet
8. Exit Temperature: 1,116 °F	9. Actual Volumetric Flow Rate: 2,393,300 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 408.835 North (km): 3354.491	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Exit temperature and flow rate are for operation of the combustion turbine on 2.0 natural gas at an ambient temperature of 59°F and operation at 100% load.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): Simple cycle combustion turbine burning 2.0 natural gas.		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 1.99 (approx.)	5. Maximum Annual Rate: 8,870 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 869 (LHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at LHV)/(fuel LHV) = hourly rate (1,736 mmBtu/hr)/(869 million scf/mmBtu) = 1.99 million scf/hour [(1,623 mmBtu/hr)/(869 million scf/mmBtu)]x(4,750 hr/yr) = 8,871 million scf/yr Approximate fuel use rates are provided for informational purposes only and do not constitute limits. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions.		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): Simple cycle combustion turbine burning 0.05% sulfur No. 2 distillate fuel oil.		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 13.9 (approx.)	5. Maximum Annual Rate: 10,431 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 131 (LHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at LHV)/(fuel LHV) = hourly rate (1,935 mmBtu/hr)/(131 mmBtu/mgal) = 14.8 mgal/hour [(1,822 mmBtu/hr)/(131 mmBtu/mgal)] x (750 hr/yr) = 10,431 mgal/yr Approximate fuel use rates are provided for informational purposes only and do not constitute limits. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): Simple cycle combustion turbine burning lower sulfur fuel oil (0.0065% sulfur, by weight).		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 14.8 (approx.)	5. Maximum Annual Rate: 13,910 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0065	8. Maximum % Ash:	9. Million Btu per SCC Unit: 131 (LHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at LHV)/(fuel LHV) = hourly rate (1,935 mmBtu/hr)/(131 mmBtu/mgal) = 14.8 mgal/hour [(1,822 mmBtu/hr)/(131 mmBtu/mgal)] x (1,000 hr/yr) = 13,908 mgal/yr Approximate fuel use rates are provided for informational purposes only and do not constitute limits. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions.		

Segment Description and Rate: Segment of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**025**	**028**	**EL**
CO			**EL**
VOC			**NS**
SO2			**EL**
PM			**EL**
PM10			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 338 lb/hour 288.9 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 0

8. Calculation of Emissions:
Hourly NO_x emission rates for simple cycle operation:
2.0 natural gas = 69.3 lb/hr (at ISO conditions) on a 24-hour block average basis
Fuel oil = 338 lb/hr @ 20°F
Potential annual emissions:
2.0 natural gas = 69.3 lb/hr
Fuel oil = 318 lb/hr @ 59°F
This permit application requests that the limit on total operation of this unit remain at 4,750 hours per year and the limit on operation with lower sulfur fuel oil (0.0065% sulfur) be set at 1,000 hours per year (compared to the current fuel oil limit of 750 hours per year). Under this scenario, worst-case annual NOx emissions are with 3,750 hours of operation on 2.0 natural gas and 1,000 hours of operation on the lower sulfur fuel oil.
Annual emissions = [(69.3 lb/hr) x (3,750 hr/yr) + (318 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 288.94 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The hourly NO_x emissions rate with operation on 2.0 natural gas is from Permit No. 0310485-005-AV and is based on a 24-hour block average as measured by the CEMS. The hourly emissions rate with operation on fuel oil are based on the permitted limit of 42 ppmvd @15% O_2 on a 3-hour average and are given for informational purposes only and do not constitute limits. The annual potential emissions are given for informational purposes only and do not constitute limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 10.5 ppmvd @ 15% O_2 while firing 2.0 natural gas	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Annual stack test	
6. Allowable Emissions Comment (Description of Operating Method): Requirement of Permit No. 0310485-005-AV. NO_x calculated as NO_2 (at ISO conditions)	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 69.3 lb/hr (at ISO conditions) 24-hr block average while firing 2.0 natural gas	4. Equivalent Allowable Emissions: 69.3 lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): Requirement of Permit No. 0310485-005-AV.	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 42 ppmvd at 15% O_2 while firing fuel oil	4. Equivalent Allowable Emissions: 338 lb/hour tons/year
5. Method of Compliance: Demonstrated by the CEMS on a 3-hr average basis. Demonstrated by stack test with NO_x emissions calculated as NO_2 (at ISO conditions)	
6. Allowable Emissions Comment (Description of Operating Method): Requirement of Permit No. 0310485-005-AV. The pound per hour equivalent emissions rate is given for informational purposes only and does not constitute a limit.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 75 ppmvd @ 15% O_2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: 40 CFR 60.334(b) Subpart GG	
6. Allowable Emissions Comment (Description of Operating Method): Rule: 40 CFR 60.334(b) Subpart GG – Standards of Performance for Stationary Gas Turbines Note: 75 ppm @ 15% O_2 is based on the equation in 40 CFR 60.332(a)(1)	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 65 lb/hour 122.5 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 0

8. Calculation of Emissions:
Hourly CO emission rates for simple cycle operation:
2.0 natural gas = 48.0 lb/hr (at ISO conditions)
Fuel oil = 65.0 lb/hr (at ISO conditions)
Potential annual emissions:
This permit application requests that the limit on total operation of this unit remain at 4,750 hours per year and the limit on operation with lower sulfur fuel oil (0.0065% sulfur) be set at 1,000 hour per year (compared to the current fuel oil limit of 750 hours per year). Under this scenario, worst-case annual CO emissions are with 3,750 hours of operation on 2.0 natural gas and 1,000 hours of operation on the lower sulfur fuel oil.
Annual emissions = [(48 lb/hr) x (3,750 hr/yr) + (65 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 122.50 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Hourly emission rates are from Permit No. 0310485-005-AV. The potential annual emissions rate is given for informational purposes only and does not constitute a limit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15 ppmvd	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 10	
6. Allowable Emissions Comment (Description of Operating Method): Requirement of Permit No. 0310485-005-AV. Applies when firing 2.0 natural gas.	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 48.0 lb/hr (ISO Conditions)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 10	
6. Allowable Emissions Comment (Description of Operating Method): Requirement of Permit No. 0310485-005-AV. Applies when firing 2.0 natural gas.	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 20 ppmvd	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 10	
6. Allowable Emissions Comment (Description of Operating Method): Requirement of Permit No. 0310485-005-AV. Applies when firing fuel oil.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 65.0 lb/hr (ISO Conditions)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 10	
6. Allowable Emissions Comment (Description of Operating Method): Requirement of Permit No. 0310485-005-AV. Applies when firing fuel oil.	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 3.0 lb/hour 6.75 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5

8. Calculation of Emissions:
Hourly VOC emission rates for simple cycle operation:
2.0 natural gas = 3.0 lb/hr @ 20°F and 2.80 @ 59°F
Fuel oil = 3.0 lb/hr @ 20°F and 3.0 lb/hr @ 59°F
Potential annual emissions:
This permit application requests that the limit on total operation of this unit remain at 4,750 hours per year and the limit on operation with lower sulfur fuel oil (0.0065% sulfur) be set at 1,000 hour per year (compared to the current fuel oil limit of 750 hours per year). Under this scenario, worst-case annual VOC emissions are with 3,750 hours of operation on 2.0 natural gas and 1,000 hours of operation on the lower sulfur fuel oil.
Annual emissions = [(2.8 lb/hr) x (3,750 hr/yr) + (3 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 6.75 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Annual potential emission calculations are based on operation at 100% load and 59°F ambient temperature. The potential hourly and annual emissions are for informational purposes only and do not constitute limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 104.30 lb/hour 58.23 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 0

8. Calculation of Emissions:
Hourly SO_2 emission rates for simple cycle operation:
2.0 natural gas = 11.4 lb/hr @ 20°F and 10.7 lb/hr @ 59°F (2 gr sulfur/100 scf)
Fuel oil (0.05% sulfur) = 104.30 lb/hr @ 20°F and 98.21 lb/hr @ 59°F
Lower sulfur fuel oil (0.0065% sulfur) = 13.56 lb/hr @ 20°F and 12.77 lb/hr @ 59°F
Potential annual emissions:
Condition A.9 of Permit No. 0310485-005-AV limits total operation to 4,750 hours per year and operation on fuel oil to 750 hours per year. Therefore, worst-case annual SO_2 emissions are with 4,000 hours of operation on 2.0 natural gas and 750 hours of operation on 0.05% sulfur fuel oil. Note that potential annual SO_2 emissions are less with the proposed lower sulfur fuel oil operating scenario.
Annual emissions = [(10.7 lb/hr) x (4,000 hr/yr) + (98.21 lb/hr) x (750 hr/yr)] / (2,000 lb/ton) = 58.23 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Emission rates are based on permitted and proposed fuel sulfur concentrations. The potential hourly and annual emissions are for informational purposes only and do not constitute limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: Use of pipeline grade 2.0 natural gas	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0065% sulfur, by weight, in the lower sulfur fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): The allowable fuel sulfur level given in Field 3 is the proposed fuel sulfur level for the lower sulfur fuel oil.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.8% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): Rule: NSPS 40 CFR 60.334(b) Subpart GG – Standards of Performance for Stationary Gas Turbines	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 34 lb/hour 50.75 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 0

8. Calculation of Emissions:
Hourly PM emission rates for simple cycle operation:
2.0 natural gas = 18 lb/hr
Fuel oil = 34 lb/hr
Potential annual emissions:
This permit application requests that the limit on total operation of this unit remain at 4,750 hours per year and the limit on operation with lower sulfur fuel oil (0.0065% sulfur) be set at 1,000 hour per year (compared to the current fuel oil limit of 750 hours per year). Under this scenario worst-case annual PM emissions are with 3,750 hours of operation on 2.0 natural gas and 1,000 hours of operation on the lower sulfur fuel oil.
Annual emissions = [(18 lb/hr) x (3,750 hr/yr) + (34 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 50.75 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Hourly emissions given in Permit No. 0310485-005-AV are 9.0 lb/hr for 2.0 natural gas firing and 17.0 lb/hr for fuel oil firing and are for front half catch only. Total (front and back half catch) emission estimates shown in Fields 3 and 8 above, are based on the assumption that total PM emissions equal twice the front half catch value. The potential emissions shown in fields 5 and 8 are given for informational purposes only and do not constitute limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 9.0 lb/hr (front half catch only)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Use of pipeline grade 2.0 natural gas	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level given in Field 3 applies when firing the emissions unit on 2.0 natural gas. The allowable emissions and method of compliance are from Permit No. 0310485-005-AV.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 17.0 lb/hr (front half catch only)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Use of 0.05% sulfur oil, by weight	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level given in Field 3 applies when firing the emissions unit on 0.05% sulfur, by weight, fuel oil. The allowable emissions and method of compliance are from Permit No. 0310485-005-AV. This limit is also proposed for use when firing the emissions unit on the lower sulfur fuel oil (0.0065%).	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 34 lb/hour 50.75 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 0

8. Calculation of Emissions:
Hourly emissions for simple cycle operation (assumes all PM is PM_{10}):
2.0 natural gas = 18 lb/hr
Fuel oil = 34 lb/hr
Potential annual emissions:
This permit application requests that the limit on total operation of this unit remain at 4,750 hours per year and the limit on operation with lower sulfur fuel oil (0.0065% sulfur) be set at 1,000 hour per year (compared to the current fuel oil limit of 750 hours per year). Under this scenario worst-case annual PM_{10} emissions are with 3,750 hours of operation on 2.0 natural gas and 1,000 hours of operation on the lower sulfur fuel oil.
Annual emissions = [(18 lb/hr) x (3,750 hr/yr) + (34 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 50.75 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
It is assumed that all PM emissions are PM_{10}. Hourly PM emissions given in Permit No. 0310485-005-AV are 9.0 lb/hr for 2.0 natural gas firing and 17.0 lb/hr for fuel oil firing and are for front half catch only. Total (front and back half catch) emission estimates as shown above are based on the assumption that total PM/PM_{10} emissions equals twice the front half catch value. The potential emissions shown in fields 5 and 8 are given for informational purposes only and do not constitute limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 10% Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: This visible emissions limit is included in Permit No. 0310485-005-AV. Per Construction Permit No. 0310485-005-AV excess emissions resulting from startup, shutdown, or malfunction are permitted provided that best operational practices are adhered to and the period of excess emissions are minimized.	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 4

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Rule: 62-204.800	

Continuous Monitoring System: Continuous Monitor 2 of 4

1. Parameter Code: O2 or CO2	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. B ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. I ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. J ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. K ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☒ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID:_____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: Attach. F
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☒ Attached, Document ID: Attach. L ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☒ Certificate of Representation (EPA Form No. 7610-1)
      ☒ Copy Attached, Document ID:Attach. M
   ☒ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☒ Attached, Document ID:Attach. M
      ☐ Previously Submitted, Date:_____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Unit 2 – One nominal 170 MW Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG

3. Emissions Unit Identification Number: 002

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			49	☒ Yes ☐ No

9. Package Unit:
Manufacturer: General Electric Model Number: GE PG7241 FA

10. Generator Nameplate Rating: 170 MW

11. Emissions Unit Comment: This emission unit is a GE PG7241 FA combustion turbine with supplemental duct burner firing. 2.0 natural gas is the primary fuel and fuel oil is the back-up fuel. This permit application seeks to include construction covered under Construction permit No. PSD-FL-310 in a revision to Operation Permit No. 0310485-005-AV. This application also seeks to add the use of lower sulfur fuel oil (0.0065% sulfur, by weight) as an additional operating segment for this emissions unit as a revision to Construction Permit No. PSD-FL-310 and Operation Permit No. 0310485-005-AV.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Dry Low-NOx (DLN) Combustor.

   Water Injection during fuel oil firing.

   Selective Catalytic Reduction (SCR).

2. Control Device or Method Code(s): 024, 028, 065

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate:			
3. Maximum Heat Input Rate:	1,911 (HHV) million Btu/hr (2.0 natural gas firing) 2,060 (HHV) million Btu/hr (Fuel oil firing)		
Duct Burner	170 (HHV) million Btu/hr (2.0 natural gas firing)		
4. Maximum Incineration Rate:	pounds/hr tons/day		
5. Requested Maximum Operating Schedule:			
For 2.0 natural gas firing:	24 hours/day	7 days/week	
CT and duct burner	52 weeks/year	8,760 hours/year	
For fuel oil firing:	16 hours/day	7 days/week	
	52 weeks/year	576 hours/year	
Proposed for lower sulfur fuel oil firing:	24 hours/day	7 days/week	
	52 weeks/year	2,000 hours/year	

6. Operating Capacity/Schedule Comment:
The heat input rates are a function of operating parameters and ambient conditions. The rates given in Field 3 are from Permit No. PSD-FL-310 and are based on the higher heating value (HHV) of each fuel. The heat input rates are included in the permit only for purposes of determining capacity during performance tests. Continuous compliance with these rates is not required.
Under permit number PSD-FL-310, the permitted annual operating rate while firing 0.05% sulfur fuel oil is 576 hours per year for unit 2 and unit 3 combined.
The proposed annual operating rate with lower sulfur fuel oil (0.0065% sulfur, by weight) is 2,000 hours per year for Unit 2 and Unit 3 combined with no short-term operational limitations.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: ID #23 on Plot Plan	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: One 190-foot vertical cylindrical exhaust stack associated with the CT/HRSG		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 190 feet	7. Exit Diameter: 18.0 feet
8. Exit Temperature: 204 °F	9. Actual Volumetric Flow Rate: 1,009,200 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: 790,100 dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 408.774 North (km): 3354.531	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Exit temperature and flow rate are for operation of the combustion turbine on 2.0 natural gas with the duct burner in operation and at an ambient temperature of 59°F and operation at 100% load.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on 2.0 natural gas. This unit is allowed to operate on 2.0 natural gas for the entire year (i.e. 8,760 hours per year).		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 1.98 (approx.)	5. Maximum Annual Rate: 16,200 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 965 (HHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate (1,910 mmBtu/hr)/(965 million scf/mmBtu) = 1.98 million scf/hour [(1,785 mmBtu/hr)/(965 million scf/mmBtu)]x(8,760 hr/yr) = 16,203 million scf/yr Approximate fuel use rates are provided for informational purposes only and do not constitute limits. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions.		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on No. 2 distillate fuel oil. The maximum allowable hours of fuel oil firing for Unit 2 and Unit 3 combined is 576 hours per consecutive 12-month period (Permit No. PSD-FL-310).		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 14.8 (approx.)	5. Maximum Annual Rate: 8,040 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 139 (HHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate (2,059 mmBtu/hr)/(139 mgal/mmBtu) = 14.81 kgal/hour [(1,939 mmBtu/hr)/(139 mgal/mmBtu)]x(576 hr/yr) = 8,035 kgal/yr The maximum annual rate is based on the assumption that combined Unit 2 and Unit 3 maximum allowable hours of fuel oil firing are all used in Unit 2. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions. Approximate fuel use rates are provided for informational purposes only and do not constitute limits.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on lower sulfur fuel oil (0.0065% sulfur, by weight). The proposed maximum allowable hours of lower sulfur fuel oil firing for Unit 2 and Unit 3 combined is 2,000 hours per consecutive 12-month period.		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 14.8 (approx.)	5. Maximum Annual Rate: 27,900 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0065	8. Maximum % Ash:	9. Million Btu per SCC Unit: 139
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate (2,059 mmBtu/hr)/(139 mgal/mmBtu) = 14.81 kgal/hour [(1,939 mmBtu/hr)/(139 mgal/mmBtu)]x(2,000 hr/yr) = 27,899 kgal/yr The maximum annual rate is based on the assumption that combined Unit 2 and Unit 3 maximum allowable hours of fuel oil firing are all used in Unit 2. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions. Approximate fuel use rates are provided for informational purposes only and do not constitute limits.		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): Duct burner operating on 2.0 natural gas.		
2. Source Classification Code (SCC):	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.18 (approx.)	5. Maximum Annual Rate: 1,540 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 965 (HHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate Maximum hourly rate = (170 mmBtu/hr)/(965 mmBtu/mmscf) = 0.176 mmscf/hr Maximum annual rate = (0.176 mmscf/hr) x (8,760 hr/yr) = 1,543 mmscf/yr Fuel use rates are a function of operating conditions. Approximate fuel use rates are provided for informational purposes only and do not constitute limits.		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**065**	**024, 028**	**EL**
CO			**EL**
VOC			**EL**
SO2			**EL**
PM			**EL**
PM10			**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 119.37 lb/hour 149.01 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5

8. Calculation of Emissions:
Highest hourly emissions for combined cycle operation:
2.0 natural gas = 24.95 lb/hr @ 20°F (w/out duct burner) and 23.92 @ 59°F (with duct burner)
Fuel oil = 119.37 lb/hr max @ 20°F and 112.41 lb/hr @ 59°F (w/out duct burner)
Potential annual emissions:
Potential annual emissions are based on operation at 100% load and 59°F and proposed maximum allowable hours of lower sulfur fuel oil (0.0065% sulfur) firing for Unit 2 and Unit 3 combined of 2,000 hours per consecutive 12-month period. For this calculation, it is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual NOx emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas.
Annual emissions = [(23.92 lb/hr) x (7,760 hr/yr) + (112.41 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 149.01 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential hourly and annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 2, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 3 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3.5 ppmvd @15% O_2 on a 3-hour block avg	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 applies when firing 2.0 natural gas. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15.0 ppmvd @15% O_2 on a 3-hour block average	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 applies when firing fuel oil. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 72.43 lb/hour 246.83 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5

8. Calculation of Emissions:
Highest hourly emissions for combined cycle operation:
2.0 natural gas = 62.57 lb/hr @ 95°F and 54.87 lb/hr @ 59°F (with duct burner)
Fuel oil = 72.43 lb/hr @ 20°F and 67.86 lb/hr @ 59°F (w/out duct burner)
Potential annual emissions:
Potential annual emissions are based on operation at 100% load and 59°F and proposed maximum allowable hours of lower sulfur fuel oil (0.0065% sulfur) firing for Unit 2 and Unit 3 combined of 2,000 hours per consecutive 12-month period. For this calculation, it is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual CO emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas.
Annual emissions = [(54.87 lb/hr) x (7,760 hr/yr) + (67.86 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 246.83 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential hourly and annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 2, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 3 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 14 ppmvd @15% O_2 on a 24-hour block average	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 applies when firing 2.0 natural gas or fuel oil. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 62.1 lb/hour 108.81 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:

8. Calculation of Emissions:
Highest hourly emissions for combined cycle operation:
2.0 natural gas = 22.02 lb/hr @ 95°F and 20.04 lb/hr @ 59°F (with duct burner)
Fuel oil = 62.1 lb/hr (w/out duct burner)
Potential annual emissions:
Potential annual emissions are based on operation at 100% load and 59°F and proposed maximum allowable hours of lower sulfur fuel oil (0.0065% sulfur) firing for Unit 2 and Unit 3 combined of 2,000 hours per consecutive 12-month period. For this calculation, it is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual PM/PM_{10} emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas.
Annual emissions = [(20.04 lb/hr) x (7,760 hr/yr) + (62.1 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 108.81 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 2, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 3 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 22.02 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Compliance demonstrated by opacity	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing 2.0 natural gas. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 62.1 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Compliance demonstrated by opacity	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing fuel oil. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 109.35 lb/hour 64.39 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:

8. Calculation of Emissions:

Highest hourly emissions for combined cycle operation:
2.0 natural gas (2 grains sulfur per 100 scf) = 12.2 lb/hr @ 20°F (w/out duct burner) and 11.70 lb/hr @ 59°F (with duct burner)
Fuel oil (0.05% sulfur) = 109.35 lb/hr @ 20°F and 102.97 lb/hr @ 59°F (w/out duct burner)
Lower sulfur fuel oil (0.0065% sulfur) = 14.22 lb/hr @ 20°F and 13.39 @ 59°F
Potential annual emissions:
Worst case potential annual emissions are based on operation at 100% load and 59°F and the maximum allowable hours of 0.05% sulfur fuel oil firing for Unit 2 and Unit 3 combined of 576 hours per consecutive 12-month period. It is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual SO_2 emissions are with 288 hours of operation on 0.05% sulfur fuel oil and 8,472 hours of operation on 2.0 natural gas. Note that potential annual SO_2 emissions are less with the proposed lower sulfur fuel oil (0.0065% sulfur) operating scenario.
Annual emissions = [(11.70 lb/hr) x (8,472 hr/yr) + (102.97 lb/hr) x (288 hr/yr)] / (2,000 lb/ton) =

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

The potential hourly and annual emissions are for informational purposes only and do not constitute limits. If all of the allowable hours of fuel oil firing were used in Unit 2, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 3 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: Use of pipeline 2.0 natural gas (2 grains sulfur per 100 standard cubic feet natural gas)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0065% sulfur, by weight, in the lower sulfur fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): The allowable fuel sulfur level given in Field 3 is the proposed fuel sulfur level for the lower sulfur fuel oil.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.8% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): Rule: NSPS 40 CFR 60.334(b) Subpart GG – Standards of Performance for Stationary Gas Turbines	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 7.68 lb/hour 19.55 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions: Highest hourly emissions for combined cycle operation: 2.0 natural gas = 6.81 lb/hr @ 95°F and 4.05 lb/hr @ 59°F (with duct burner) Fuel oil = 7.68 lb/hr @ 59°F (w/out duct burner) (permit limit) Potential annual emissions: Potential annual emissions are based on a proposed maximum allowable hours of fuel oil firing for Unit 2 and Unit 3 combined with lower sulfur fuel oil (0.0065% sulfur) of 2,000 hours per consecutive 12-month period with these hours of operation evenly split between Unit 2 and Unit 3. Therefore, worst-case annual VOC emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas. Annual emissions = [(4.05 lb/hr) x (7,760 hr/yr) + (7.68 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 19.55 ton/yr	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 2, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 3 would than decrease by an equal amount.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 6.81 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 18, 25 or 25A	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing 2.0 natural gas. The allowable emissions level is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 7.68 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 18, 25 or 25A	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing fuel oil. The allowable emissions level is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: This visible emissions limit is included in Permit No. 0310485-005-AV. Per Construction Permit No. 0310485-005-AV excess emissions resulting from startup, shutdown, or malfunction are permitted provided that best operational practices are adhered to and the period of excess emissions are minimized.	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Rule: 40 CFR 60 and 40 CFR Part 75. Use of CEMS is required by Construction Permit No. PSD-FL-310.	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Use of CEMS is required by Construction Permit No. PSD-FL-310.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: CO2	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Use of CEMS is required by Construction Permit No. PSD-FL-310.	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. B ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. I ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. J ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. K ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☒ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: Attach. F
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☒ Attached, Document ID: Attach. L ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☒ Certificate of Representation (EPA Form No. 7610-1)
      ☒ Copy Attached, Document ID: Attach. M
   ☒ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☒ Attached, Document ID: Attach. M
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Not Applicable

EMISSIONS UNIT INFORMATION
Section [2] of [4]

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Unit 3 – One nominal 170 MW Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG

3. Emissions Unit Identification Number: 003

4. Emissions Unit Status Code: A	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☒ Yes ☐ No

9. Package Unit:
Manufacturer: General Electric Model Number: GE PG7241 FA

10. Generator Nameplate Rating: 170 MW

11. Emissions Unit Comment: This emission unit is a GE PG7241 FA combustion turbine with supplemental duct burner firing. 2.0 natural gas is the primary fuel and fuel oil is the back-up fuel. This permit application seeks to include construction covered under Construction permit No. PSD-FL-310 in a revision to Operation Permit No. 0310485-005-AV. This application also seeks to add the use of lower sulfur fuel oil (0.0065% sulfur, by weight) as an additional operating segment for this emissions unit as a revision to Construction Permit No. PSD-FL-310 and Operation Permit No. 0310485-005-AV.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Dry Low-NOx (DLN) Combustor.

   Water Injection during fuel oil firing.

   Selective Catalytic Reduction (SCR).

2. Control Device or Method Code(s): 024, 028, 065

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate:			
3. Maximum Heat Input Rate:	1,911 (HHV) million Btu/hr (2.0 natural gas firing) 2,060 (HHV) million Btu/hr (Fuel oil firing)		
Duct Burner	170 (HHV) million Btu/hr (2.0 natural gas firing)		
4. Maximum Incineration Rate:	pounds/hr tons/day		
5. Requested Maximum Operating Schedule:			
For 2.0 natural gas firing:	24 hours/day	7 days/week	
CT and duct burner	52 weeks/year	8,760 hours/year	
For fuel oil firing:	16 hours/day	7 days/week	
	52 weeks/year	576 hours/year	
Proposed for lower sulfur fuel oil firing:	24 hours/day	7 days/week	
	52 weeks/year	2,000 hours/year	

6. Operating Capacity/Schedule Comment:
The heat input rates are a function of operating parameters and ambient conditions. The rates given in Field 3 are from Permit No. PSD-FL-310 and are based on the higher heating value (HHV) of each fuel. The heat input rates are included in the permit only for purposes of determining capacity during performance tests. Continuous compliance with these rates is not required.
Under permit number PSD-FL-310, the permitted annual operating rate while firing 0.05% sulfur fuel oil is 576 hours per year for unit 2 and unit 3 combined.
The proposed annual operating rate with lower sulfur fuel oil (0.0065% sulfur, by weight) is 2,000 hours per year for Unit 2 and Unit 3 combined with no short-term operational limitations.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: ID #23 on Plot Plan	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: One 190-foot vertical cylindrical exhaust stack associated with the CT/HRSG		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 190 feet	7. Exit Diameter: 18.0 feet
8. Exit Temperature: 204 °F	9. Actual Volumetric Flow Rate: 1,009,200 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: 790,100 dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 408.774 North (km): 3354.531	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Exit temperature and flow rate are for operation of the combustion turbine on 2.0 natural gas with the duct burner in operation and at an ambient temperature of 59°F and operation at 100% load.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on 2.0 natural gas. This unit is allowed to operate on 2.0 natural gas for the entire year (i.e. 8,760 hours per year).		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 1.98 (approx.)	5. Maximum Annual Rate: 16,200 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 965 (HHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate (1,910 mmBtu/hr)/(965 million scf/mmBtu) = 1.98 million scf/hour [(1,785 mmBtu/hr)/(965 million scf/mmBtu)]x(8,760 hr/yr) = 16,203 million scf/yr Approximate fuel use rates are provided for informational purposes only and do not constitute limits. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions.		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on No. 2 distillate fuel oil. The maximum allowable hours of fuel oil firing for Unit 2 and Unit 3 combined is 576 hours per consecutive 12-month period (Permit No. PSD-FL-310).		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 14.8 (approx.)	5. Maximum Annual Rate: 8,040 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 139 (HHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate (2,059 mmBtu/hr)/(139 mgal/mmBtu) = 14.81 kgal/hour [(1,939 mmBtu/hr)/(139 mgal/mmBtu)]x(576 hr/yr) = 8,035 kgal/yr The maximum annual rate is based on the assumption that combined Unit 2 and Unit 3 maximum allowable hours of fuel oil firing are all used in Unit 3. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions. Approximate fuel use rates are provided for informational purposes only and do not constitute limits.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on lower sulfur fuel oil (0.0065% sulfur, by weight). The proposed maximum allowable hours of lower sulfur fuel oil firing for Unit 2 and Unit 3 combined is 2,000 hours per consecutive 12-month period.		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 14.8 (approx.)	5. Maximum Annual Rate: 27,900 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0065	8. Maximum % Ash:	9. Million Btu per SCC Unit: 139
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate (2,059 mmBtu/hr)/(139 mgal/mmBtu) = 14.81 kgal/hour [(1,939 mmBtu/hr)/(139 mgal/mmBtu)]x(2,000 hr/yr) = 27,899 kgal/yr The maximum annual rate is based on the assumption that combined Unit 2 and Unit 3 maximum allowable hours of fuel oil firing are all used in Unit 3. Actual fuel use rates are a function of the fuel heating value and the emission unit operating conditions. Approximate fuel use rates are provided for informational purposes only and do not constitute limits.		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): Duct burner operating on 2.0 natural gas.		
2. Source Classification Code (SCC):	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.18 (approx.)	5. Maximum Annual Rate: 1,540 (approx.)	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 965 (HHV)
10. Segment Comment: Approximate fuel use rate calculations: (heat input at HHV)/(fuel HHV) = hourly rate Maximum hourly rate = (170 mmBtu/hr)/(965 mmBtu/mmscf) = 0.176 mmscf/hr Maximum annual rate = (0.176 mmscf/hr) x (8,760 hr/yr) = 1,543 mmscf/yr Fuel use rates are a function of operating conditions. Approximate fuel use rates are provided for informational purposes only and do not constitute limits.		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**065**	**024, 028**	**EL**
CO			**EL**
VOC			**EL**
SO2			**EL**
PM			**EL**
PM10			**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 119.37 lb/hour 149.01 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5

8. Calculation of Emissions:
Highest hourly emissions for combined cycle operation:
2.0 natural gas = 24.95 lb/hr @ 20°F (w/out duct burner) and 23.92 @ 59°F (with duct burner)
Fuel oil = 119.37 lb/hr max @ 20°F and 112.41 lb/hr @ 59°F (w/out duct burner)
Potential annual emissions:
Potential annual emissions are based on operation at 100% load and 59°F and proposed maximum allowable hours of lower sulfur fuel oil (0.0065% sulfur) firing for Unit 2 and Unit 3 combined of 2,000 hours per consecutive 12-month period. For this calculation, it is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual NOx emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas.
Annual emissions = [(23.92 lb/hr) x (7,760 hr/yr) + (112.41 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 149.01 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential hourly and annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 3, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 2 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3.5 ppmvd @15% O_2 on a 3-hour block avg	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 applies when firing 2.0 natural gas. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15.0 ppmvd @15% O_2 on a 3-hour block average	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 applies when firing fuel oil. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 72.43 lb/hour 246.83 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5

8. Calculation of Emissions:

Highest hourly emissions for combined cycle operation:
2.0 natural gas = 62.57 lb/hr @ 95°F and 54.87 lb/hr @ 59°F (with duct burner)
Fuel oil = 72.43 lb/hr @ 20°F and 67.86 lb/hr @ 59°F (w/out duct burner)
Potential annual emissions:
Potential annual emissions are based on operation at 100% load and 59°F and proposed maximum allowable hours of lower sulfur fuel oil (0.0065% sulfur) firing for Unit 2 and Unit 3 combined of 2,000 hours per consecutive 12-month period. For this calculation, it is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual CO emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas.
Annual emissions = [(54.87 lb/hr) x (7,760 hr/yr) + (67.86 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 246.83 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

The potential hourly and annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 3, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 2 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 14 ppmvd @15% O_2 on a 24-hour block average	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 applies when firing 2.0 natural gas or fuel oil. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 62.1 lb/hour 108.81 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:

8. Calculation of Emissions:
Highest hourly emissions for combined cycle operation:
2.0 natural gas = 22.02 lb/hr @ 95°F and 20.04 lb/hr @ 59°F (with duct burner)
Fuel oil = 62.1 lb/hr (w/out duct burner)
Potential annual emissions:
Potential annual emissions are based on operation at 100% load and 59°F and proposed maximum allowable hours of lower sulfur fuel oil (0.0065% sulfur) firing for Unit 2 and Unit 3 combined of 2,000 hours per consecutive 12-month period. For this calculation, it is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual PM/PM_{10} emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas.
Annual emissions = [(20.04 lb/hr) x (7,760 hr/yr) + (62.1 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 108.81 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 3, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 2 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 22.02 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Compliance demonstrated by opacity	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing 2.0 natural gas. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 62.1 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Compliance demonstrated by opacity	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing fuel oil. The allowable emissions level is BACT and is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 109.35 lb/hour 64.39 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:

8. Calculation of Emissions:

Highest hourly emissions for combined cycle operation:
2.0 natural gas (2 grains sulfur per 100 scf) = 12.2 lb/hr @ 20°F (w/out duct burner) and 11.70 lb/hr @ 59°F (with duct burner)
Fuel oil (0.05% sulfur) = 109.35 lb/hr @ 20°F and 102.97 lb/hr @ 59°F (w/out duct burner)
Lower sulfur fuel oil (0.0065% sulfur) = 14.22 lb/hr @ 20°F and 13.39 @ 59°F
Potential annual emissions:
Worst case potential annual emissions are based on operation at 100% load and 59°F and the maximum allowable hours of 0.05% sulfur fuel oil firing for Unit 2 and Unit 3 combined of 576 hours per consecutive 12-month period. It is assumed that these hours of operation are evenly split between Unit 2 and Unit 3. Therefore, worst-case annual SO_2 emissions are with 288 hours of operation on 0.05% sulfur fuel oil and 8,472 hours of operation on 2.0 natural gas. Note that potential annual SO_2 emissions are less with the proposed lower sulfur fuel oil (0.0065% sulfur) operating scenario.
Annual emissions = [(11.70 lb/hr) x (8,472 hr/yr) + (102.97 lb/hr) x (288 hr/yr)] / (2,000 lb/ton) =

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

The potential hourly and annual emissions are for informational purposes only and do not constitute limits. If all of the allowable hours of fuel oil firing were used in Unit 3, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 2 would then decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: Use of pipeline 2.0 natural gas (2 grains sulfur per 100 standard cubic feet natural gas)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0065% sulfur, by weight, in the lower sulfur fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): The allowable fuel sulfur level given in Field 3 is the proposed fuel sulfur level for the lower sulfur fuel oil.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.8% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Custom Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): Rule: NSPS 40 CFR 60.334(b) Subpart GG – Standards of Performance for Stationary Gas Turbines	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 7.68 lb/hour 19.55 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:

8. Calculation of Emissions:
Highest hourly emissions for combined cycle operation:
2.0 natural gas = 6.81 lb/hr @ 95°F and 4.05 lb/hr @ 59°F (with duct burner)
Fuel oil = 7.68 lb/hr @ 59°F (w/out duct burner) (permit limit)
Potential annual emissions:
Potential annual emissions are based on a proposed maximum allowable hours of fuel oil firing for Unit 2 and Unit 3 combined with lower sulfur fuel oil (0.0065% sulfur) of 2,000 hours per consecutive 12-month period with these hours of operation evenly split between Unit 2 and Unit 3. Therefore, worst-case annual VOC emissions are with 1,000 hours of operation on the lower sulfur fuel oil and 7,760 hours of operation on 2.0 natural gas.
Annual emissions = [(4.05 lb/hr) x (7,760 hr/yr) + (7.68 lb/hr) x (1,000 hr/yr)] / (2,000 lb/ton) = 19.55 ton/yr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential annual emissions are for informational purposes only and do not constitute limits. If all of the proposed allowable hours of fuel oil firing were used in Unit 3, the annual potential emissions would be greater than shown. However, the annual potential emissions for Unit 2 would than decrease by an equal amount.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 6.81 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 18, 25 or 25A	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing 2.0 natural gas. The allowable emissions level is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 7.68 lb/hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: EPA Method 18, 25 or 25A	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate in Field 3 applies when firing fuel oil. The allowable emissions level is found in Permit No. PSD-FL-310.	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: This visible emissions limit is included in Permit No. 0310485-005-AV. Per Construction Permit No. 0310485-005-AV excess emissions resulting from startup, shutdown, or malfunction are permitted provided that best operational practices are adhered to and the period of excess emissions are minimized.	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Rule: 40 CFR 60 and 40 CFR Part 75. Use of CEMS is required by Construction Permit No. PSD-FL-310.	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Use of CEMS is required by Construction Permit No. PSD-FL-310.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: CO2	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Use of CEMS is required by Construction Permit No. PSD-FL-310.	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. B ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. I ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. J ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. K ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☒ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: Attach. F
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☒ Attached, Document ID: Attach. L ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☒ Certificate of Representation (EPA Form No. 7610-1)
      ☒ Copy Attached, Document ID: Attach. M
   ☒ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☒ Attached, Document ID: Attach. M
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Not Applicable

EMISSIONS UNIT INFORMATION
Section [3] of [4]

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☒ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☒ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Mechanical Draft Cooling Tower

3. Emissions Unit Identification Number: 007

4. Emissions Unit Status Code: C	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Drift eliminators will be used to reduce PM/PM_{10} emissions.

2. Control Device or Method Code(s): 015

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate:	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	 days/week hours/year
6. Operating Capacity/Schedule Comment:	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: F	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [4] of [4]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☐ Attached, Document ID: _____
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: _____ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:_____
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:_____
      ☐ Previously Submitted, Date:_____
   ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [4] of [4]

Additional Requirements Comment

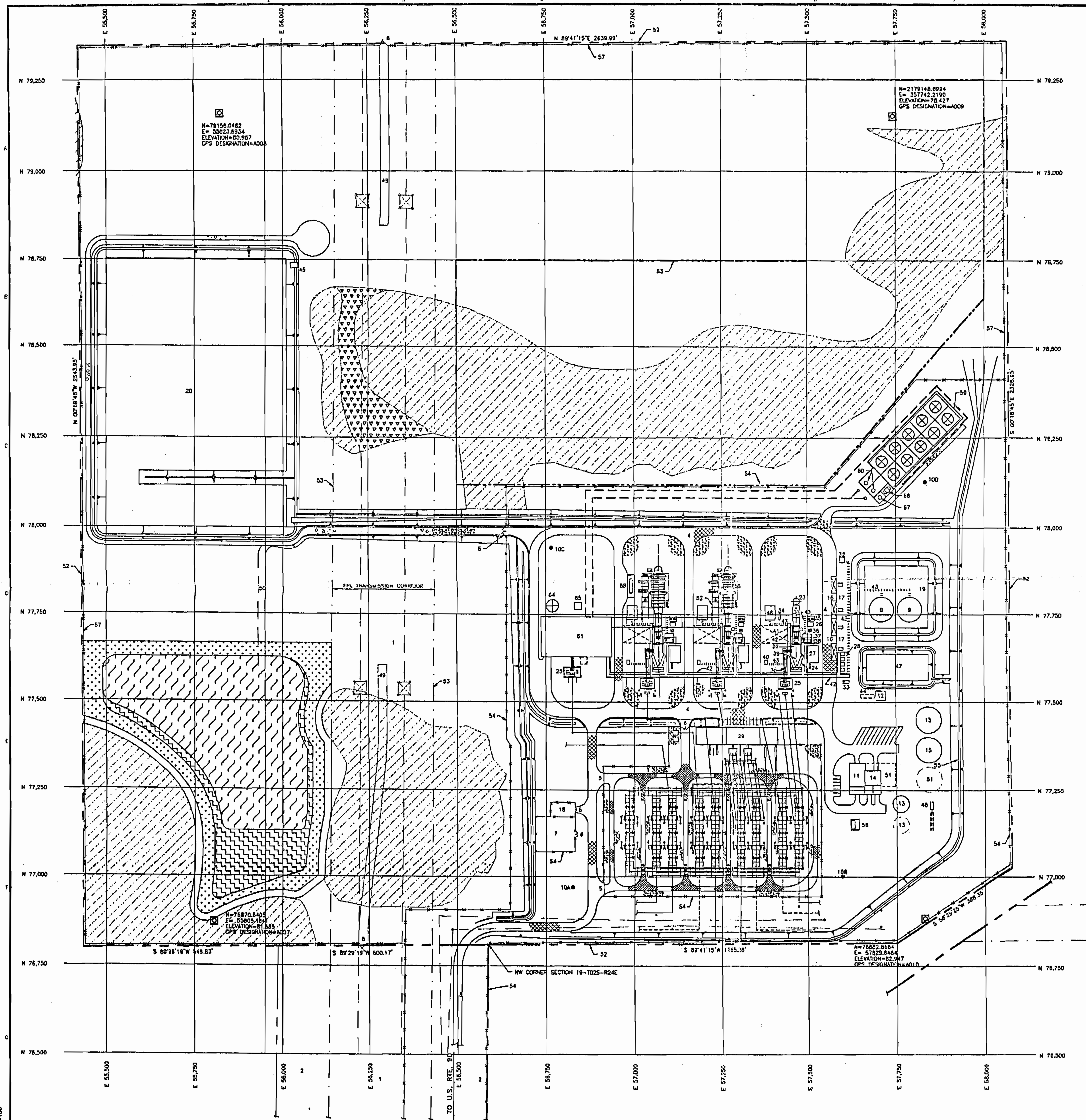
Attachment A

Facility Plot Plan

BEST AVAILABLE COPY

0310485-007-AC

(1)



FACILITIES LEGEND

ITEM NO	DESCRIPTION	LOCATION COORDINATES NORTH	LOCATION COORDINATES EAST	REFERENCE LOCATION
1	F.P.&L. RIGHT-OF-WAY	N/A	N/A	
2	JEA TRANSMISSION CORRIDOR	N/A	N/A	
3	ACCESS ROAD	N/A	N/A	
4	LOOP ROAD	N/A	N/A	
5	SLIDE GATE	N/A	N/A	
6	SWING GATE	N/A	N/A	
7	FUEL GAS METERING STATION	N/A	N/A	
8	SUBSTATION AREA	N/A	N/A	
9	FUEL OIL STORAGE TANK (1,000,000 GALLONS)	N/A	N/A	
10A	WATER SUPPLY WELL	76970.00	56825.00	CL WELL
10B	WATER SUPPLY WELL	77001.82	57597.00	CL WELL
10C	WATER SUPPLY WELL	77943.00	567645.00	CL WELL
10D	WATER SUPPLY WELL	78128.00	57834.00	CL WELL
11	SHOP/STORAGE BUILDING	N/A	N/A	
12	WASTEWATER PUMPING STATION	N/A	N/A	
13	RAW WATER/FIRE WATER STORAGE TANK	N/A	N/A	
14	MECHANICAL EQUIPMENT BUILDING	N/A	N/A	
15	DEMINERALIZED WATER STORAGE TANK	N/A	N/A	
16	FUEL OIL UNLOADING AREA	N/A	N/A	
17	FUEL OIL UNLOADING PUMP AREA	N/A	N/A	
18	HYDROGEN STORAGE GAS AREA	N/A	N/A	
19	FUEL OIL STORAGE TANK SECONDARY CONTAINMENT	N/A	N/A	
20	STORM WATER DETENTION POND	N/A	N/A	
21	COMBUSTION TURBINE (CT)	N/A	N/A	
22	CT GENERATOR	N/A	N/A	
23	CT EXHAUST STACK (UNIT 1)	77788.26	57468.00	CL STACK
23	CT EXHAUST STACK (UNIT 2)	N/A	N/A	
23	CT EXHAUST STACK (UNIT 3)	N/A	N/A	
24	CT AIR INLET FILTER	N/A	N/A	
25	GENERATOR STEP-UP TRANSFORMER	N/A	N/A	
26	CT WATER INJECTION SKID	N/A	N/A	
27	CONTROL/ELECTRICAL BUILDING	N/A	N/A	
28	FUEL FORWARDING SKIDS	N/A	N/A	
29	CONTROL/SHARED SERVICES BUILDING	N/A	N/A	
30	UNIT AUXILIARY TRANSFORMER	N/A	N/A	
31	EXHAUST DUCT SILENCER	N/A	N/A	
32	FIRE PROTECTION FOAM HOUSE	N/A	N/A	
33	WASH WATER SKID	N/A	N/A	
34	MISCELLANEOUS DRAIN TANK	N/A	N/A	
35	CT CO2 FIRE PROTECTION SKID	N/A	N/A	
36	FALSE START DRAIN TANK	N/A	N/A	
37	LIQUID FUEL/ATOMIZING AIR MODULE	N/A	N/A	
38	CT ACCESSORY MODULE	N/A	N/A	
39	GENERATOR COMPARTMENT	N/A	N/A	
40	FIRE WATER DELUGE HOUSE	N/A	N/A	
41	MAINTENANCE AREA	N/A	N/A	
42	PIPE TRENCH	N/A	N/A	
43	SLEEPER PIPE RACK	N/A	N/A	
44	OIL WATER SEPARATOR	N/A	N/A	
45	STORM WATER DETENTION POND DISCHARGE STRUCTURE	N/A	N/A	
46	COOLER	N/A	N/A	
47	PERCOLATION POND	N/A	N/A	
48	SEPTIC TANK AND DRAINFIELD DETAIL	N/A	N/A	
49	EXISTING ROAD	N/A	N/A	
50	TEMPORARY CONSTRUCTION ACCESS ROAD	N/A	N/A	
51	FUTURE WATER TREATMENT EQUIPMENT EXPANSION	N/A	N/A	
52	PROPERTY BOUNDARY	N/A	N/A	
53	EASEMENT BOUNDARY	N/A	N/A	
54	CHAIN LINK SECURITY FENCE	N/A	N/A	
55	PERIMETER [illegible]	N/A	N/A	
56	LUBE OIL STORAGE AREA	N/A	N/A	
57	BARBED WIRE SITE PERIMETER FENCE	N/A	N/A	
58	HEAT RECOVERY STEAM GENERATOR	N/A	N/A	
59	COOLING TOWER	N/A	N/A	
60	CIRCULATING WATER PUMPS	N/A	N/A	
61	STEAM TURBINE GENERATOR BUILDING	N/A	N/A	
62	ABOVE GROUND PIPE RACK	N/A	N/A	
63	CONSERVATION EASEMENT	N/A	N/A	
64	CONDENSATE STORAGE TANK	N/A	N/A	
65	WASTEWATER SUMP	N/A	N/A	
66	CIRCULATING WATER ACID TANK	N/A	N/A	
67	CIRCULATING WATER HYPOCHLORITE TANK	N/A	N/A	
68	AMMONIA STORAGE TANK	N/A	N/A	

GENERAL LEGEND

- BENCHMARK
- FUTURE FACILITY
- WETLANDS
- CYPRESS (ZONE 2) AREA
- ASPHALT
- CRUSHED ROCK SURFACING
- HERBACEOUS (ZONE 1) AREA
- UPLAND SEEDING AREA
- RESTORATION MITIGATION AREA
- GEOWEB

NOT TO BE USED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE		
C	10-13-2000	GENERAL REVISIONS	WG	JMS
B	09-19-2000	GENERAL REVISIONS	WG	SKW
A	09-05-2000	ISSUED FOR REVIEW	WG	SKW

SCALE: 1"=100' (100' 50' 0 100' 200')

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.

SIGNED ______ DATE ______ REG NO. ______

BLACK & VEATCH — JEA Building Community

ENGINEER SKW — DRAWN WG — CHECKED — DATE

JEA
BRANDY BRANCH COMBINED CYCLE PROJECT
SITE ARRANGEMENT

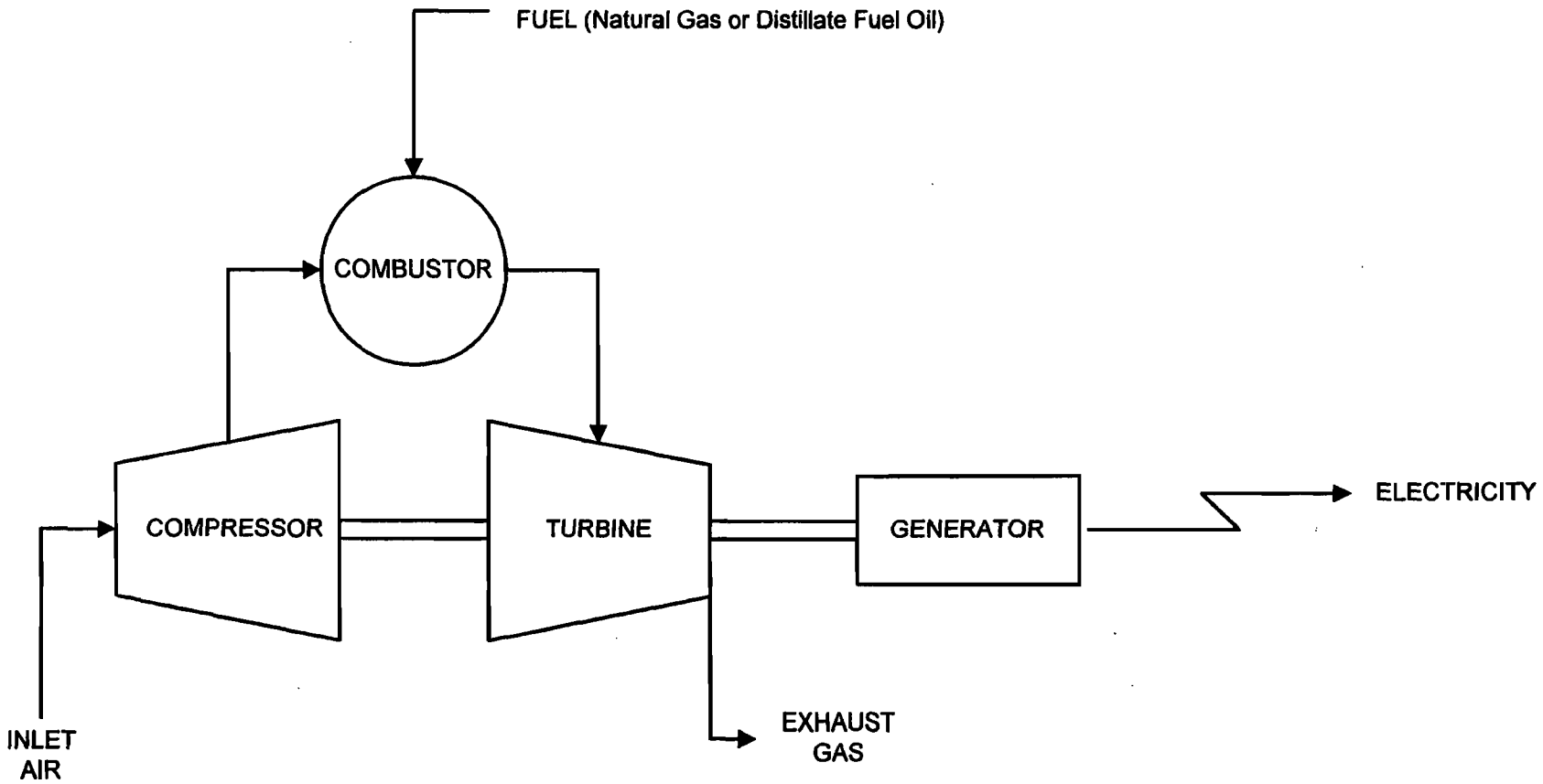
PROJECT 97990 — DRAWING NUMBER DS-0001 — REV C

ERA07739 E1 ACAD 15.05 1=100
10/13/00 09:07:09

Attachment B

Process Flow Diagrams

Jacksonville Electric Authority
Brandy Branch Facility
Facility ID: Unknown



Simple Cycle Combustion Turbine
Process Flow Diagram

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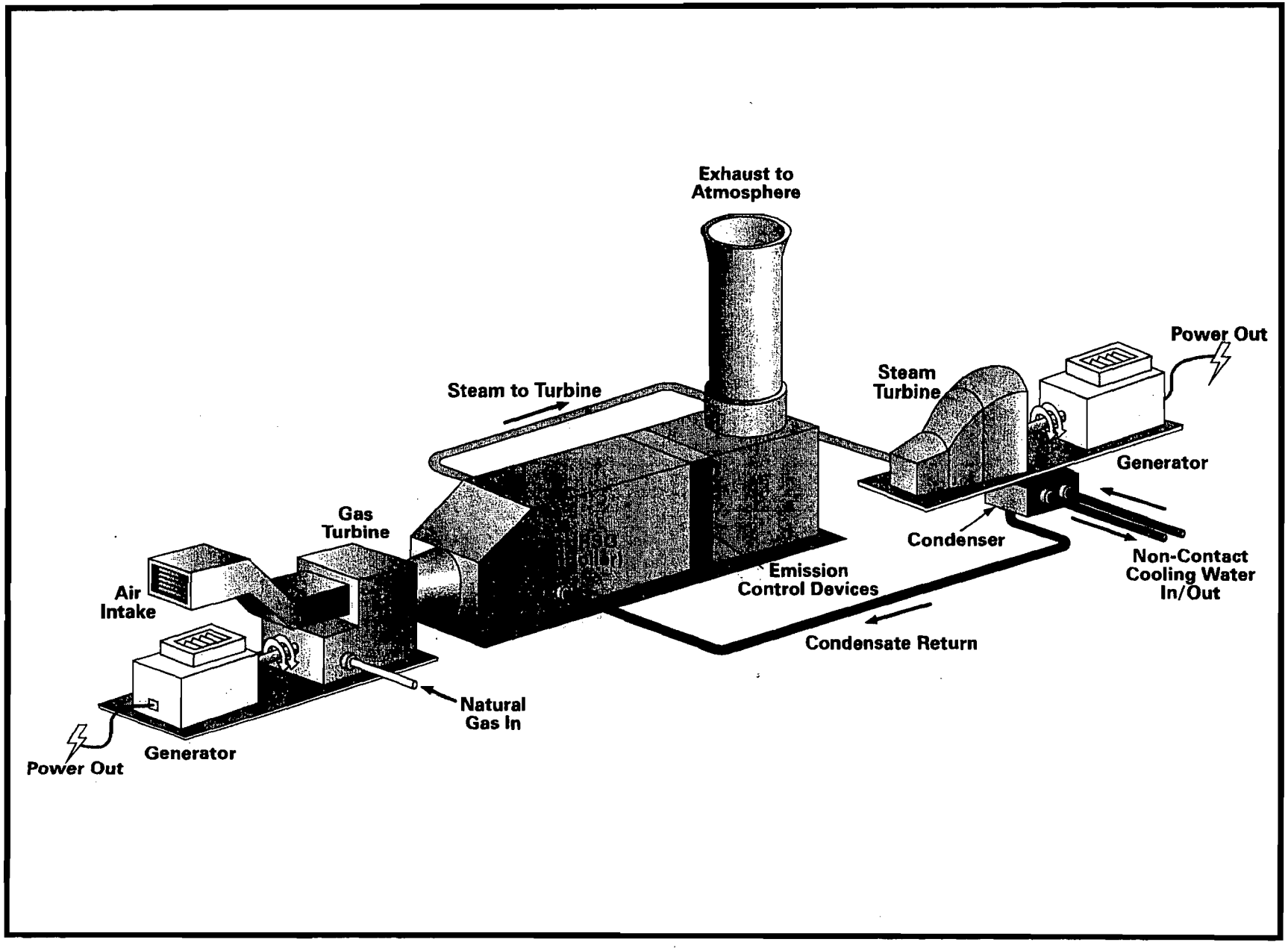

Attachment C

Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

The facility has negligible amounts of unconfined particulate matter as a result of the operation of the facility. Potential examples of particulate matter include:

- Fugitive dust from paved and unpaved roads;
- Sandblasting abrasive material from facility maintenance activities.

Several precautions were taken to prevent emissions of particulate matter in the original design of the facility. These include:

- Paving of roads, parking areas and equipment yards;
- Landscaping and planting of vegetation.

Operational measures are undertaken at the facility which also minimize particulate emissions, in accordance with Rule 62-296.320(4)(c) F.A.C.:

- Maintenance of paved areas as needed;
- Regular mowing of grass and care of vegetation;
- Limiting access to plant property for unnecessary vehicles.

Attachment D

Description of Proposed Modification

Description of Proposed Modification

See the letter report accompanying this application for a description of the proposed modification covered under this application.

Attachment E

Rule Applicability Analysis

Rule Applicability Analysis

See the letter report accompanying this application for a discussion on rule applicability.

Attachment F

Identification of Applicable Requirements

Identification of Applicable Requirements

List of facility-wide applicable regulations

- Facility-wide applicable regulations specified in construction permit PSD-FL-310 are hereby incorporated by reference.
- Facility-wide applicable regulations hereby incorporates by reference the Title V core list of applicable regulations that all Title V sources are presumptively subject.

Unit 1 – List of applicable regulations

- Applicable regulations specified in existing Title V permit 0310485-005-AV for Unit 1 are hereby incorporated by reference.
- Emission unit applicable regulations hereby incorporates by reference the Title V core list of applicable regulations that all Title V sources are presumptively subject.
- 40 CFR 60, Subpart A
- 40 CFR 60, Subpart GG
- 40 CFR 72
- 40 CFR 73
- 40 CFR 75
- 40 CFR 77
- 62-204.800(8)(c)
- 62-204.800(8)(d)
- 62-204.800(8)(b)39
- 62-204.800(8)(e)
- 62-204.800(16)
- 62-204.800(17)
- 62-204.800(18)
- 62-204.800(18)
- 62-214
- 62-297.401
- Jacksonville Environmental Protection Board, Rule 2
- Ordinance Code, City of Jacksonville, Title X, Chapter 376
- Ordinance Code, City of Jacksonville, Title V, Chapter 362

Unit 2 – List of applicable regulations

- Applicable regulations specified in construction permit PSD-FL-310 for Unit 2 are hereby incorporated by reference.
- Emission unit applicable regulations hereby incorporates by reference the Title V core list of applicable regulations that all Title V sources are presumptively subject.
- 40 CFR 60, Subpart A
- 40 CFR 60, Subpart GG
- 40 CFR 60, Subpart Db
- 40 CFR 72
- 40 CFR 73
- 40 CFR 75
- 40 CFR 77

- 62-204.800(8)(c)
- 62-204.800(8)(d)
- 62-204.800(8)(b)39
- 62-204.800(8)(b)3
- 62-204.800(8)(e)
- 62-204.800(16)
- 62-204.800(17)
- 62-204.800(18)
- 62-204.800(20)
- 62-214
- 62-297.401
- Jacksonville Environmental Protection Board, Rule 2
- Ordinance Code, City of Jacksonville, Title X, Chapter 376
- Ordinance Code, City of Jacksonville, Title V, Chapter 362

Unit 3 – List of applicable regulations

- Applicable regulations specified in construction permit PSD-FL-310 for Unit 3 are hereby incorporated by reference.
- Emission unit applicable regulations hereby incorporates by reference the Title V core list of applicable regulations that all Title V sources are presumptively subject.
- 40 CFR 60, Subpart A
- 40 CFR 60, Subpart GG
- 40 CFR 60, Subpart Db
- 40 CFR 72
- 40 CFR 73
- 40 CFR 75
- 40 CFR 77
- 62-204.800(8)(c)
- 62-204.800(8)(d)
- 62-204.800(8)(b)39
- 62-204.800(8)(b)3
- 62-204.800(8)(e)
- 62-204.800(16)
- 62-204.800(17)
- 62-204.800(18)
- 62-204.800(20)
- 62-214
- 62-297.401
- Jacksonville Environmental Protection Board, Rule 2
- Ordinance Code, City of Jacksonville, Title X, Chapter 376
- Ordinance Code, City of Jacksonville, Title V, Chapter 362

Attachment G

Compliance Report and Plan

Compliance Report and Plan

Because the combined cycle combustion turbines (Units 2 and 3) have not yet begun operation, the initial compliance tests required by Construction Permit PSD-FL-310 have not been completed. Initial compliance tests required by Construction Permit PSD-FL-310 will be completed in accordance with Permit PSD-FL-310 under the following compliance plan:

- Required notification of the compliance test dates will be made to FDEP.
- Stack testing will be performed in accordance with appropriate EPA/FDEP test methods.
- FDEP will be notified when a compliance test has been completed.
- JEA will submit the results of each compliance test to FDEP within 45 days of completion of that compliance test.

If new regulatory requirements become applicable in the future, or if any non-compliance items are discovered after submittal of this application, the necessary steps will be taken to ensure compliance in a timely manner. This is in accordance with company policy of maintaining continuous compliance with all applicable rules and regulations.

Attachment H

Requested Changes to Current Title V Air Operation Permit

Requested Changes to Current Title V Operating Permit

See the letter report accompanying this application for a discussion on requested changes to existing facility permits.

Attachment I

Fuel Analysis or Specification

Fuel Analysis or Specification

Fuel is specified as pipeline quality sweet 2.0 natural gas (2 grains per 100 standard cubic foot), No. 2 distillate fuel oil containing no more than 0.05% sulfur and lower sulfur fuel oil containing no more than 0.0065% sulfur.

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FLORIDA GAS TRANSMISSION COMPANY
FERC Gas Tariff
Third Revised Volume No. 1

Third Revised Sheet No. 102C
Superseding
Second Revised Sheet No. 102C

GENERAL TERMS AND CONDITIONS
(continued)

am. GISB Definitions - shall mean any such definitions issued by GISB which have been adopted by the FERC. Transporter incorporates GISB Definitions (Version 1.3, July 31, 1998) 1.2.8 through 1.2.12 and 4.2.1 through 4.2.8 by reference herein.

2. QUALITY

A. Gas delivered by Shipper or for its account into Transporter's pipeline system at receipt points shall conform to the following quality standards:

1. shall be free from objectionable odors, solid matter, dust, gums, and gum forming constituents, or any other substance which might interfere with the merchantability of the gas stream, or cause interference with proper operation of the lines, meters, regulators, or other appliances through which it may flow;

2. shall contain not more than seven (7) pounds of water vapor per one thousand (1,000) MCF;

3. shall contain not more than one quarter (1/4) grain of hydrogen sulphide per one hundred (100) cubic feet of gas;

4. shall contain not more than ten (10) grains of total sulphur per one hundred (100) cubic feet of gas;

5. shall contain not more than a combined total three percent (3%) by volume of carbon dioxide and/or nitrogen;

6. shall contain not more than one quarter percent (1/4%) by volume of oxygen;

Issued by: Robert B. Kilmer, Vice President
Issued on: July 1, 1999

Effective: August 1, 1999

index of pages previous page next page

SPECIFICATIONS FOR #2 LOW SULFUR DIESEL FUEL

The oil shall be hydrocarbon oil, free from alkali, mineral acid, grit, fibrous or other foreign matter and shall meet the following physical and chemical properties:

1) Gravity: A.P.I. 30 minimum (ASTM D287)

2) Flash: 130 F minimum (ASTM D93)

3) Viscosity: Kinematic, Centistokes at 100 F, minimum 2.0, maximum 3.0 (ASTM D445)

4) Water & Sediment: .50% maximum, (ASTM D1796 or D2700)

5) Pour Point: 0 F maximum (ASTM D97)

6) Distillation: 10% Point, 480 F maximum, 90% Point, 640 F maximum, End Point 690 F maximum (ASTM D86)

7) Sulfur: Low Sulfur - 0.05% maximum (ASTM D129 or D1552),

8) BTU: minimum 138,000 BTU's per gallon (ASTM D240)

9) Carbon Residue on 10% bottoms: .25 Max (ASTM D189)

10) Trace Metals (PPM, Max):
- Calcium 4.0
- Lead 1.0
- Potassium 2.0
- Vanadium 1.5.

Specifications for lower sulfur fuel oil

The lower sulfur fuel oil is expected to have the same specifications as the #2 low sulfur diesel fuel, except the sulfur content will be a maximum 0.0065%, by weight.

Attachment J

Detailed Description of Control Equipment

Detailed Description of Control Equipment

For Unit No. 1 with natural gas firing, low NO_x burners will be used to control NO_x emissions. For Unit No. 1 with fuel oil firing, water injection will be used to limit NO_x emissions by lowering the combustion temperature. For further information on Unit No. 1 control equipment refer to the simple cycle combustion turbine PSD application submitted to FDEP in May 1999.

For Unit No. 2 and Unit No. 3 with natural gas firing, dry low NO_x burners with an SCR will be used to limit NO_x emissions. For Unit No. 2 and Unit No. 3 with fuel oil firing, water injection with an SCR will be used to limit NO_x emissions. For further information on Unit No. 2 and Unit No. 3 control equipment refer to Appendix 10.7 – PSD Application of the Site Certification Application for the JEA Brandy Branch Combined Cycle Conversion submitted to FDEP in December 2000.

Attachment K

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

Startup and shutdown will be completed in accordance with the manufacturers' operating procedures and/or based on plant experience. Excess emissions from startup and shutdown are permitted in condition 25 of PSD permit PSD-FL-310 and by condition A.15 of operation permit No. 0310485-005-AV.

Attachment L

Alternative Methods of Operation

Alternative Methods of Operation

Emission Units 001, 002 and 003 can operate on pipeline quality 2.0 natural gas (2 grains sulfur per 100 standard cubic foot), No. 2 distillate fuel oil (0.05% sulfur) and Lower sulfur fuel oil (0.0065%)

The following operating limitations are for the operation of Units No. 1, No.2 and No. 3 on natural gas and/or 0.05% sulfur fuel oil. These are the currently permitted operational limits:

- Annual hours of operation:
  - Simple Cycle Unit (Unit No. 1)
    - 4,750 hours total.
    - 750 hours of operation with the 0.05% sulfur fuel oil.
  - Combined Cycle Units (Unit No. 1 and Unit No. 2)
    - No limit on total annual hours of operation.
    - 576 total hours of operation with 0.05% sulfur fuel oil firing for Unit No. 2 and Unit No. 3 combined.

- Short-term operational limits:
  - No daily limitations are required when firing only natural gas in Unit No.1, Unit No. 2 and Unit No. 3.
  - When any of the three combustion turbines (Unit No. 1, Unit No. 2 or Unit No. 3) fires 0.05% sulfur fuel oil during a calendar day that combustion turbine is limited to 16 hours of daily operation on any fuel for that calendar day. Also, the other two Units shall not be fired on any day in which 0.05% sulfur fuel oil is fired in one of the Units.

The following operating limitations are proposed for the operation of Units No. 1, No.2 and No. 3 on natural gas and/or the lower sulfur fuel oil:

- Annual hours of operation:
  - Simple Cycle Unit (Unit No. 1)
    - 4,750 hours total (as currently permitted).
    - 1,000 hours of operation with the lower sulfur fuel oil.
  - Combined Cycle Units (Unit No. 1 and Unit No. 2)
    - No limit on total annual hours of operation (as currently permitted).
    - 2,000 total hours of operation with lower sulfur fuel oil firing for Unit No. 2 and Unit No. 3 combined.

- Short-term operational limits:
  - No daily limitations are required when firing only natural gas in Unit No.1, Unit No. 2 and Unit No. 3. (same as currently permitted)
  - With Unit No. 2 or Unit No. 3 firing lower sulfur fuel oil:

- No daily limitation on Unit No. 2 or Unit No. 3. Each of Unit No. 2 and Unit No. 3 are allowed to fire either natural gas or lower sulfur fuel oil for the entire calendar day (24 hr/day).
- Unit No. 1 is limited to 8 hours of operation on any fuel on any day in which lower sulfur fuel oil is fired in Unit No.2 or Unit No. 3.

o With Unit No. 1 firing lower sulfur fuel oil for more than 8 hours during a calendar day:
- Unit No. 2 and Unit No. 3 shall not be fired on lower sulfur fuel oil during any calendar day in which Unit No. 1 is fired with lower sulfur fuel oil for more than 8 hours.
- On calendar days in which Unit No. 2 and Unit No. 3 do not fire lower sulfur fuel oil, Unit No. 1 is allowed to fire either natural gas or lower sulfur fuel oil for the entire calendar day (24 hr/day).

Attachment M

Acid Rain Part Application

JEA

December 30, 1999

Mr. Scott Sheplak, P.E.
Title V Administrator
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee. FL 32399-2400

RE: Brandy Branch Facility
Acid Rain Application Forms

Dear Mr. Sheplak:

Enclosed please find the Acid Rain Application Forms for the Brandy Branch Facility.

If you have any questions with regard to this matter, please contact me at (904) 665-6247.

Sincerely.

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

cc: USEPA
USEPA, Region 4

bc: J. Connolly
E. Mims
L. Starner
B. Gianazza
File

bbacidrain

Phase II Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: ☒ New ☐ Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	Brandy Branch	State	FL	ORIS Code	7846

STEP 2 Enter the boiler ID# from NADB for each affected unit and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

a	b	c	d	e
Boiler ID#	Compliance Plan: Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Compliance Plan: Repowering Plan	New Units: Commence Operation Date	New Units: Monitor Certification Deadline
001	Yes		Dec. 2000	Dec. 2000
002	Yes		Dec. 2000	Dec. 2000
003	Yes		Dec. 2001	Dec. 2001
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes for any unit

☐ For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

Plant Name (from Step 1) **Brandy Branch**

TEP 4
ad the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C. in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from Step 1) **Brandy Branch**

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Jon P. Eckenbach	
Signature	Date 12-14-99

STEP 5 (optional)
Enter the source AIRS FINDS identification

AIRS
FINDS

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24

This submission is: [X] New [ ] Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 [ ]

STEP 1
Identify the source by plant name, State, and ORIS code.

Plant Name	State	ORIS Code
Brandy Branch	FL	7846

STEP 2
Enter requested information for the designated representative.

Name	Jon P. Eckenbach
Address	21 West Church Street Jacksonville, Florida 32202
Phone Number	(904) 665-6315
Fax Number	(904) 554-7366
E-mail address (if available)	eckejp@jea.com

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name	Tim E. Perkins
Phone Number	(904) 665-4520
Fax Number	(904) 665-7376
E-mail address (if available)	perkte@jea.com

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the designated representative for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and

Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1) Brandy Branch

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (designated representative)	Date 12-14-99
Signature (alternate designated representative)	Date 12-16-99

STEP 5
Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.

Name JEA					[X] Owner	[X] Operator
ID# 001	ID# 002	ID# 003	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

January 19, 2000

Mr. N. Bert Gianazza, P.E.
Environmental Permitting & Compliance Group
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Re: Acid Rain Phase II Permit Application
Brandy Branch Facility; ORIS Code: 7846

Dear Mr. Gianazza:

Thank you for your recent submission of the Acid Rain Phase II Permit Application for the subject facility. We have reviewed the document and found it to be complete.

Sincerely,

Scott M. Sheplak, P.E.
Administrator
Title V Section

cc: Jenny Jachim, EPA Region 4

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24
This submission is: ☐ New ☒ Revised (revised submissions must be completed in full; see instructions)
This submission includes combustion or process sources under 40 CFR part 74 ☐

STEP 1
Identify the source by plant name, State, and ORIS code.

Plant Name	State	ORIS Code
Brandy Branch	FL	7846

STEP 2
Enter requested information for the designated representative.

Name	Jon P. Eckenbach, Executive Vice President
Address	21 West Church Street Jacksonville, FL 32202
Phone Number	(904) 665-6315
Fax Number	(904) 665-7366
E-mail address (if available)	eckejp@jea.com

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name	Susan Hughes, Vice President
Phone Number	(904) 665-6248
Fax Number	(904) 665-7376
E-mail address (if available)	hughsn@jea.com

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and

Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1)	Brandy Branch

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (designated representative)	Date 11/14/00
Signature (alternate designated representative)	Date 11/17/00

STEP 5
Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.

Name JEA					☒ Owner	☒ Operator
ID# 1	ID# 2	ID# 3	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#