

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an _____
Application for Permit by:

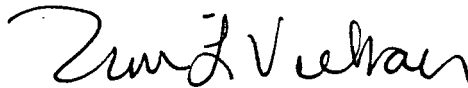
Mr. H. O. Nuñez, Plant General Manager
Florida Power and Light Company, Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

DEP File No. PSD-FL-338
FP&L Turkey Pt. Unit 5
Miami-Dade County

Enclosed is the Final Permit Number PSD-FL-338 (0250003-006-AC) to construct/install a nominal 1,150 MW combined cycle ("4 on 1") unit and auxiliary equipment at the Turkey Point Fossil Plant near Homestead, Miami-Dade County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.



Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

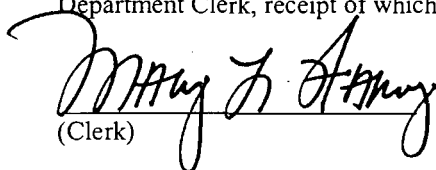
The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were sent by U.S. Mail or electronic mail before the close of business on 2/8/05 to the person(s) listed:

H. O. Nuñez, FPL*
John Gnecco, FPL
Randall LaBauve, FPL*
Barbara Linkiewicz, FPL
Mayor, Miami-Dade County
Mayor, City of Homestead
Mayor, Florida City
John Benjamin, Everglades National Park
Linda Canzanelli, Biscayne National Park

Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Steven L. Palmer, DEP Siting Office
Kevin Neal, DEP SED
Bruce Offord, DEP SED
Paul Darst, Department of Community Affairs
Chair, Miami-Dade County EQCB
H. Patrick Wong, Miami-Dade County DERM
Ken Kosky, P.E., Golder

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date,
pursuant to §120.52, Florida Statutes, with the designated
Department Clerk, receipt of which is hereby acknowledged.

 2/6/05
(Clerk) (Date)

FINAL DETERMINATION
File No. 0250003-006-AC (PSD-FL-338)
FP&L TURKEY POINT POWER PLANT
COMBINED CYCLE UNIT 5

The Department distributed a Public Notice package on May 28, 2004 for the project to construct a natural gas-fired combined cycle unit to be known as Unit 5 – FP&L Turkey Point Power Plant east of Homestead and Florida City and adjacent to Biscayne Bay, Miami-Dade County. The 1150MW project consists of four nominal 170 MW General Electric combustion turbine-electrical generators, four heat recovery steam generators, a 470 MW steam-electrical generator, and a mechanical draft cooling tower. The Public Notice of Intent to Issue was published in the June 10th edition of the Miami Herald.

No requests for public meetings or administrative hearings were received on the Notice of Intent to Issue. An evidentiary hearing was held on September 20-21, 2004 and a Recommended Order was entered on November 18, 2004 to:

“Grant full and final certification to Florida Power & Light Company, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Turkey Point Unit 5, representing a 1150 MW combined cycle unit, as described in the Site Certification Application and the evidence presented at the certification hearing, and subject to the Conditions of Certification.” Final Certification was approved on February 1, 2005.

The Department is required to take final action on the PSD Permit Application and the draft permit within 30 days following Final Certification by the Siting Board. This Final Determination recapitulates all comments and changes since the distribution of the Notice of Intent to Issue PSD Permit on May 28, 2004.

No comments suggesting adverse impacts were received. The comments of the EPA, NPS and FP&L recited or described below (*italics*) followed by the Department’s responses.

1. *EPA’s letter dated July 8, 2004 states, “Condition 9 of the draft PSD permit contains a table of CO emissions limits that are applicable to various operating modes of the four new CTs. The table contains two columns of emission limits. Compliance with the first column of emission limits shall be demonstrated by 3-run stack testing, while compliance with the second column of emission limits shall be demonstrated using a continuous emissions monitoring system (CEMS) with a 24-hour averaging time”.*

The Department agrees with the given description of the table, the limits and how compliance will be demonstrated. But as noted in item 5 below, we reserve use of CEMS for short-term.

2. *EPA’s letter further states, “It is our understanding from conversations with the Florida Department of Environmental Protection (FDEP) that the first column of CO emission limits represents the BACT emission limits (i.e., 4.1 ppm in normal mode, 7.6 ppm with duct burning, etc.) and the second column of CO emission limits contains higher limits that have been proposed to simplify the recordkeeping process (i.e., 8.0 ppm for all modes except power augmentation, etc.). First, we would like to point out that the distinction between the two sets of emission limits described above is not clear in the current draft PSD permit”.*

The 5 ppm value (~4 when corrected to 15% O₂) is the lowest CO limit guaranteed to-date by any combustion turbine manufacturer without requiring installation of additional control equipment such as oxidation catalyst. The 7.6 ppm limit with duct burning and 8 ppm limit for fuel oil use are also the lowest values in permits without oxidation catalyst and represent values roughly equivalent to ambient air quality standards even though measured at the stack.

To simplify recordkeeping, a 24-hour limit of 8 ppm was proposed because it is possible that on a given day, a combined cycle unit will actually operate with the duct burner on at all times. The distinction between the limits is maintained because initial and annual stack tests are required for the three key modes in conjunction with the annual RATA tests for the CEMS.

The remaining concern is that the low guaranteed values for the normal gas-firing case (without high power modes) is not accounted for in the CEMS based limit. To insure that the units cannot possibly be operated at 8 ppm at all times regardless of mode, the Department will set a limit of 6 ppmvd @15% O₂ on a 12 month basis, rolled monthly. This represents an approximate weighted average of emissions based on permitted firing modes. It assumes that the individual units will operate all of the allowable hours in the high power or oil-firing modes and the difference on the normal gas only mode.

The additional requirement will not cause increases or reductions in emissions or cause undue recordkeeping burdens. However the new requirement better represents the long-term, time averaged, emission estimates over all modes of operation consistent with the application.

Based on review of CO data after startup, the Department expects actual average emissions for all modes between 1 to 2 ppm except for the limited power augmentation mode. It is not yet possible to obtain the very low guarantees without installing oxidation catalyst. For reference, emissions during the limited power augmentation mode will likely be between 5 and 9 ppm.

3. *EPA's letter states, "If the emission limits are left as they are, this relationship should be better described in the table itself or in a permitting note immediately preceding the table".*

The table has been updated to clarify CO emission limits:

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.0, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12 months

- a. Continuous compliance with the 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
4. *EPA's letter states, "We agree with FDEP that initial compliance with the BACT limits can be determined using a stack test; however, continuous compliance with the BACT emission limits should be demonstrated by use of the CEMS".*

The issue relates to CO. The table now represents a reasonable compromise that provides an additional incentive to the applicant to operate based on initial and annual stack tests. The alternative of separate continuous compliance for each and every mode is feasible but cumbersome. Continuous compliance is demonstrated by the use of CEMS for the 24-hour and 12 month standards.

5. *EPA's letter states, "Condition 19 of the draft PSD permit declares that FDEP "reserves the right" to use data from the CEMS to determine compliance with the short-term CO emission limits. We believe that this condition is not definite enough to enforce the BACT emission limits using CEMS".*

This "right" that was placed in the draft permit provides a powerful incentive to maintain the equipment such that the lowest emissions are achieved. It is not much different than the use of "any credible evidence" in addition to the already stringent stack test and CEM-based BACT emission limits. With the new weighted annual limit for CO, there is an even bigger incentive to comply with the short-term values.

6. *EPA's letter states, "If it is decided that the CEMS will be used to determine compliance with the BACT emission limits, we recommend that the final PSD permit require use of an averaging time shorter than 24 hours. Since there exist short-term CO national ambient air quality standards (NAAQS) with averaging times below 24 hours (i.e., 1-hour and 8-hour standards), we believe that the averaging times should be more consistent with the applicable NAAQS averaging times".*

The range of emission limits for the various modes is 4 to 14 ppm, while expected emissions are 1 to 2 ppm at the stack exit and prior to dilution and dispersion for all but one case. We actually expect emissions of 5 to 9 ppm for the limited power augmentation case. The 1-hour and 8-hour ground level National Ambient Air Quality Standards for CO are 35 and 9 ppm respectively. Even if all of the allowable emissions in a 24-hour period were compressed into a single hour, the ground level concentration would still not exceed 9 ppm. Thus the 24-hour limit is protective of the 1 and 8-hour CO standards. There are no increments for CO that might otherwise reinforce the need for the shorter averaging periods.

7. *EPA states, "any operating limits which were used in the analyses on a per turbine basis should be included in the draft PSD permit on a per turbine basis. The draft PSD permit does contain per turbine limits on the amount of time the CTs can operate in power augmentation mode and while firing fuel oil. However, condition 8(e) of the draft PSD permit contains one aggregate limit (5,702,400 MMBtu) for all four CTs restricting the*

amount of duct firing that is allowed in a year. In order for the BACT analysis to remain valid, the final PSD permit should contain the appropriate duct firing limit on a per turbine basis (i.e., 1,425,600 MMBtu/year). Alternatively, if the applicant wishes to retain the aggregate limit, a revised BACT analysis should be performed (based on the worst case scenario of one CT operating the duct burners all year long) which demonstrates that the outcome of the BACT analysis would remain unchanged”.

The point is well taken and the following review was conducted to determine if a further BACT review is needed. Referring to 4 above, the Department has added a long-term limit of 6 ppm CO.

The scenario of firing a single duct burner continuously for the year while hardly firing the others is unrealistic but theoretically possible and needs to be explored. The practical consequence of continuous duct firing is that the given unit must still comply with the BACT NO_x limit of 2 ppm. NO_x emissions will actually be controlled to that level or slightly less by the SCR system.

The CO could theoretically be 7.6 ppm of CO. However if they use the duct burners continuously, they are limited by the new 12 month of 6 ppm (corrected to 15% O₂). GE will guarantee CO emissions from its combustion turbines to 5 ppm uncorrected (~ 4.1 ppm corrected). The duct burner manufacturer has its own guarantee regarding what a duct burner *theoretically adds* to the CO from the combustion turbine.

The Department's analysis of *actual* operating data shows that duct burners do not affect CO emissions in a meaningful manner for F-Class installations. Exhaust gas from the combustion turbine is already at a high temperature, turbulent, and contains a lot of oxygen promoting good CO burnout. The guarantees for the different components have not yet been reconciled into a single low CO guarantee without requiring oxidation catalyst.

Based on the Department's analysis of data from installations with GE F-Class combustion turbines operating in conjunction with duct burners, actual emissions will be in the range of 1 to 2 ppm @15% O₂. The data on the duct burners operating in conjunction with the combustion turbines was included in the Technical Evaluation.

The Department believes that it is not cost-effective to install oxidation catalyst to reduce CO emissions for this part-time mode from 6 to say 1 ppm @15% O₂ when the practical reduction will actually be from the 1 – 2 ppm range to 0.2– 0.4 ppm (assuming roughly 80 percent efficiency). The equipment providers have given their best guarantees short of installing unnecessary oxidation catalyst. This FP&L project was the first to obtain such low guarantees.

Basically, the Department has required FP&L to meet a value lower than the combined guarantees of the combustion turbine provider and the duct burner provider. The data from installations in Florida and the underpinning provided in the Technical Evaluation provide further reasonable assurance that the new long term limit can be achieved and that emissions will in fact be substantially less than permitted.

The Department agrees that FP&L will be able to theoretically fire the duct burner all of the time on one unit and none of the time on others. Although this is a very unlikely situation for economic reasons, the Department believes that the outcome of the BACT analysis would remain unchanged based on the information above.

8. *In the NPS letter dated July 2, 2004, NPS states, "Although FDEP acknowledges that the high power operating modes 'can cause greater uncontrolled NO_x emissions' the proposed permit explicitly exempts FP&L from any emission limits while operating in this mode".*

The Department's BACT determination of 2.0 ppm NO_x limit does apply to all modes except for use of back up ultralow sulfur fuel oil. The Department clarified this issue during discussions with NPS experts on November 24, 2004. After jointly studying the table containing the emissions limits for each power mode, we agreed that the proposed permit does not exempt high power modes from the BACT determination.

9. *In the same letter, the NPS states, "FP&L will reduce their NO_x limit from 2.5 ppm to 2.0 ppm when burning natural gas and from 10.0 ppm to 8.0 ppm when burning oil At the lower NO_x emission rates; we anticipate that visibility impacts at Biscayne NP will also be reduced. Therefore, we do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP".*

The Department agrees with this assessment.

10. *The NPS letter included comments related to the averaging time of the 24-hr NO_x emission limit of 2.0 ppmvd @15% O₂ when burning natural gas. It states, "BACT is an emission limit, and emission limits typically consist of a numerical limit in terms of mass of pollutant per unit time, unit volume and/or per unit of heat input. These emission limits are also typically specified over a prescribed averaging period; due to the inherent variability in emissions and the performance of the control technology, the longer the averaging period, the easier it is to meet a given limit.*

"Although it states in the TEPD top-down analysis that 'The Top emission limit is considered by the Department to be 2.0 ppmvd @ 15% O₂ on a 1-hour average,' FDEP goes on to set FP&L's proposed permit limit for natural gas combustion based upon a 24-hour average, with no explanation provided for the longer averaging period. Therefore, FDEP did not choose the 'top' control technology, nor did it justify proposing a less stringent limit.

"We believe that the 24-hour block averaging periods are much too long when compared to similar combustion turbines meeting the same outlet concentration limits for the one-hour or three-hour averages. The effect of the much longer averaging periods is to reduce the stringency of the limits relative to other permits. For example, Clark County, Nevada, has determined that a 2.0 ppm limit (1-hr average) represents BACT for the Diamond Generating, Ivanpah Energy combustion turbine project. The Virginia Department of Environmental Protection has permitted an identical limit for the CPV Warren County combustion turbine project. Turkey Point should show why it cannot meet a 2.0 ppm limit on a one-hour basis, as it is required of other similar projects".

It is important to note that the NSPS standard for combustion turbines is approximately 108 ppm for F-Class units on a 4 hour basis. The proposed BACT is 2 ppm on a 24-hr basis or only 2 percent of the standard. This is virtually zero for this pollutant in terms of emissions and it is very difficult to achieve lower emissions.

In addition, the NO_x ambient standard is on an annual basis. The 24-hour standard for this source is suitable to limit effects on visibility and ozone formation potential. A one-hour value is achievable but runs the risk that small exceedances that do not have any impacts will be categorized as violations. In any case, the facility would have to compensate quickly when the value exceeds 2 ppm even on a 24-hour average. For example, if a unit were to emit even 10 ppm for four hours, it would have to achieve 0.4 ppm during the preceding and subsequent 20 hours to avoid exceeding the 24-hr limit.

While it is difficult to prove that it is not cost-effective to reduce the averaging time to 1 hour, the Department has a great deal of experience balancing emission limits and averaging times with environmental protection and sensible business operation. This case-by-case BACT determination and combination of limit and averaging time will allow this facility to conduct its business, protect the environment, respond smoothly to operational variations, and dispatch power from other system facilities in an orderly fashion.

The considerations in out-of-state non-attainment areas or sources that influence such non-attainment areas may be somewhat different. The Department does not assert that any of the determinations made in the areas described by NPS are erroneous with respect to limits or averaging time.

In the conversations of November 24, the NPS personnel acknowledged that the Department would make the final BACT determination.

11. *NPS states in its letter dated July 2, 2004, "As referenced in our February 24, 2004 letter to FDEP regarding the emission inventories presented in the FP&L permit application, we reiterate that we would like to know how sources were selected for the inventory, and how emissions from those sources were determined."*

FP&L and Golder referred to their letter dated April 19, 2004 that was in response to the NPS letter dated February 24. The relevant parts follow.

"Cumulative Source Modeling- The detailed stack, operating, and emission data for the facilities with SO₂ and PM₁₀ sources presented in Tables 6-3 and 6-4 are provided in Tables D-1 and D-2 of Appendix D to the Air Construction Permit/PSD Application, Appendix 10.1.5.

"These data were based on information provided from FDEP, available from recent PSD permit applications, Title V permits, and supplemented with current and historical information available within Golder. The air modeling data were obtained from several recently submitted and reviewed air permit applications in which PSD Class I increment or significant impact analyses were performed at the Everglades National Park. These applications include the modifications to U.S. Sugar Corporation's Clewiston Mill (proposed Boiler No. 8, March 2003; Boiler No. 4 and Sugar Refinery, October 2000); Palm Beach

Power Corporation's Cogeneration Facility (April 2002); and FPL's Martin Power Plant Expansion Project, Unit No. 8 (February 2002).

"The major source baseline date for Florida is January 6, 1975 for both SO₂ and PM₁₀ (adopted and incorporated by reference in Rule 62-204.800, F.A.C.). The minor source baseline date for SO₂ and PM₁₀ has been set as December 27, 1977 for the entire State of Florida (Rule 62-204.360(1) and (2), F.A.C.).

"Based on these baseline dates, the baseline and PSD-increment consuming sources of SO₂ and PM₁₀ emissions for the sources in the inventory were developed from the available information discussed previously. The baseline and PSD increment consuming sources are identified in Tables D-1 and D-2 of Appendix A to the Air Construction/PSD Application.

"It should be noted that, although the highest 24-hour average SO₂ concentrations were predicted to exceed 24-hour SO₂ PSD Class I increment for 1990 and 1992, there were no predicted violations of the increment based on the highest, second highest values. Rule 62-272.500 F.A.C. and 40 CFR 52.21(c) support the use of the highest, second highest values when determining compliance with the 24-hour SO₂ PSD Class I increment".

12. *During the telephone discussion of November 24, 2004 NPS advised that the inventory and the modeling for SO₂ Class I Increment Consumption described in the Golder/FP&L response did not, but should have, included minor sources, transportation, and changes in major sources on an actual to actual basis since 1977.*

Turkey Pt. Unit 5 will fire the lowest sulfur fuels available. The project will be the first in Florida to commit to ultralow sulfur fuel oil used as backup fuel to natural gas. The backup fuel actually has a lower sulfur specification than natural gas. NPS advised (see 9 above) they do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP. The Department agrees with NPS.

After receiving clarification from NPS on November 24, 2004 the Department reviewed the issues raised by the NPS. The Department agrees that the analysis for Class I SO₂ Increment Consumption does not comport with the method most recently described by the NPS.

The Department conducted a qualitative and semi-quantitative evaluation and determined that additional modeling, if conducted in the manner described by NPS, will most likely show expansion rather than consumption of SO₂ increment by development since the late 1970's and that the proposed project will not appreciably change that trend. The Department responded to the NPS comments by electronic mail on December 8, 2004. The communication contained most of the following analysis:

The Department obtained information from FP&L regarding actual emissions from the existing Turkey Point units circa 1977. In 2002, emissions were 9,135 tons from Turkey Point Units 1 and 2. During the 1974-1978 timeframe, emissions from Turkey Points Units 1 and 2 were always much higher and averaged 16,558 tons per year. Therefore, the biggest sources (Units 1 and 2) likely to interact with the new project (that will emit 193 tons per year) have expanded increment rather than consumed increment. The summary table of emissions from Turkey Point is shown below.

Emissions of SO₂ from Turkey Point Fossil Plant (1974-78, and 2002)

<u>Year</u>	<u>Tons per year</u>
1974	18,043
1975	18,058
1976	18,028
1977	13,519
1978	15,140
1974-1978	16,558 (average)
2002	9,135
Reduction	~ 7,000

Table 16 from the Technical Evaluation distributed with the Department's Draft PSD Permit lists the largest stationary SO₂ sources in Miami-Dade County and their *actual* emissions.

Table 16. Major Sources of SO₂ in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Florida Power & Light	Turkey Pt. Plant (existing boilers)	9,135 (EPA)
Titan Industries	Tarmac Pennsucco Cement	~ 1,000 (est.)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	231
<i>Florida Power & Light</i>	<i>Turkey Pt. Plant (proposed project)</i>	<i>193</i>
Waste Management	Medley Landfill and Recycling	129
Miami-Dade County WASD	MDWASD/Central District WWTP	88

The magnitude of actual large SO₂ emission sources drops off very rapidly after the existing Turkey Point Fossil Plant. Titan/Tarmac Pennsucco Cement will emit closer to 50 TPY (rather than ~1000 TPY) in future years, having modernized their process in 2004. Rinker Cement previously emitted over 1000 TPY of SO₂ and now emits approximately 50 TPY since a modernization project in 2000. General Portland Cement was another significant emitter of SO₂ that closed around 1985.

The 7,000 TPY actual reduction from the collocated Turkey Point Units 1 and 2 and the reductions from reductions in regional cement manufacturing SO₂ emissions would overwhelm any possible effects from the 193 TPY Turkey Point Unit 5.

During the application review phase, FP&L submitted estimates that 2008-2012 SO₂ emissions from Turkey Point Units 1 and 2 will be approximately 5,733 tons per year. The Department does not necessarily agree with or reject these estimates given uncertain fuel prices.

The Department also included in the Technical Evaluation an inventory of the different categories of emissions in Miami-Dade County. The small magnitude of the proposed Turkey Pt. Unit 5 project is obvious.

Table 21. Pollutant Emissions in Miami-Dade County by Source Category (2002)

Source Category	SO ₂	NO _x	CO	PM ₁₀	VOC	NH ₃
Stationary Sources	10,262	12,929	3,891	2,516	1,757	0 (?)
Area Sources	13,266	4,580	78,670	35,438	53,167	2,925
On-Road Mobile	1,989	46,158	492,121	1,230	49,007	1,940
Non-Road Mobile	1,976	19,062	197,091	24,946	15,646	11
Total	27,492	82,729	771,773	64,131	119,578	4,876
<i>Turkey Pt. Unit 5</i>	193	320	450	229	68	~200

Transportation SO₂ emissions are likely lower in recent years than in the baseline years of the late 1970's. Most of the decline is due to the use of 0.05% sulfur fuel oil for transportation versus the previous higher sulfur specifications in gasoline and diesel (e.g. 0.5% sulfur for diesel). Ultralow sulfur fuel oil (0.0015% sulfur) for transportation sources has been mandated so the trend will continue. Any area source/minor source increases would have been very small compared with the reductions at Turkey Point.

The Department issued a permit in 1998 that lead to the actual SO₂ emissions reductions greater than 20,000 TPY from the FP&L Fort Myers Power Plant located 97 km north of the westernmost part of ENP. This expanded increment over the ENP from a generally northwesterly direction. The 1992 natural gas repowering of the FP&L Lauderdale Plant in Dania expanded increment at ENP from a generally northeasterly direction.

Similarly, the FP&L Port Everglades Plant in Broward County and the FP&L Rivera Plant in Palm Beach County use cleaner fuel oil than required and use substantial amounts of natural gas. This probably adds further to any actual to actual analysis of increment expansion.

In conclusion all indications are that SO₂ emissions have been reduced locally and regionally. A modeling effort would likely show improvements rather than degradation related to SO₂ at the ENP since the late 1970's. The Department believes this analysis is sufficient to support issuance of this permit without further detailed analysis.

13. In a letter received July 2, 2004 from FP&L (Barbara Linkiewicz), FPL requested revision of Section III, specific condition 8, b. as follows:

Authorized fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. ~~Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months.~~ The four gas turbines shall fire no more than a cumulative total of 28,028,168 gallons of fuel oil during any calendar year.

Following discussions with the Department and considering EPA's concern regarding the fuel versus hourly limitation for duct burning, FP&L withdrew the request. In this case, the theoretical, but unlikely use of fuel oil for 2000 hours in a single unit and 0 hours in the others might have changed the final BACT.

By electronic communication dated August 15, 2004, FP&L replaced their request in Item 13 with the following:

Authorized Fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months calendar year.

The revised request has no practical effect on emissions or the BACT basis for SO₂. The Department will revise the Authorized Fuels condition per the revised request.

14. In the July 2, 2004 letter, FP&L requests the following change to Section III, Specific Condition 9.f.:

Each SCR system shall be designed and operated for ammonia slip limit of less no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs.

The Department will revise this emission standard adding the proposed language.

15. In the July 2, 2004 letter, FPL states:

"In Section III, pages 14-15, we request the clarifications below. Recognizing that quarterly reports contain all NSPS and State requirements, this clarification combines the quarterly and semi annual reports. The proposed language below also makes Condition 27 consistent with Condition 25a regarding the monitoring period".

Condition 27. ~~Semiannual NSPS Excess Emissions Report. Quarterly Excess Emission Report:~~ In accordance with 40 CFR 60.7 (d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards following the NSPS format provided in Appendix XS of this permit. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_x emission standard identified in Appendix GG; and any daily monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown. An example of the report is provided on Appendix XS. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

~~Condition 28. Quarterly Permit Excess Emissions Report Semiannual NSPS Excess Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7] The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.~~

The Department will adopt these changes with some additional clarification. The reports will include excess emissions related to the BACT determination and any other SIP-based emission limits in addition to the NSPS excess emission reporting requirements.

The other change reflects the recent revision of 40 CFR 60 Subpart GG that defines excess emissions based on CEMS in lieu of water-to-fuel ratio.

16. *On August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. The relevant provision of the rule that stays the effectiveness for units such as proposed at Turkey Point follows:*

40 CFR 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

The Department has updated relevant parts of the permit and summarized in Appendix YYYY of the permit, the applicable requirements of Subparts A and YYYY in 40 CFR 63.

CONCLUSION

The final action of the Department is to issue the permit with the changes noted above.



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

PERMITTEE:

Florida Power & Light
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Scott Stone, Plant General Manager

FP&L Turkey Point Fossil Plant
DEP File No. 0250003-006-AC
Permit No. PSD-FL-338
SIC No. 4911
Expires: December 31, 2008

PROJECT AND LOCATION

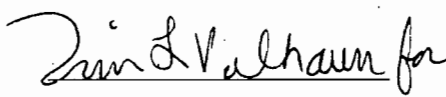
This permit authorizes the construction of Unit 5 at the existing FP&L Turkey Point Fossil Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will include four 170 MW gas turbine-electrical generator sets, four heat recovery steam generators, a single 470 MW steam turbine-electrical generator, and a mechanical draft cooling tower. The existing FP&L Turkey Point Fossil Plant is located east of Homestead and Florida City and next to Biscayne Bay in Miami-Dade County, Florida. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

- Section I. General Information
- Section II. Administrative Requirements
- Section III. Emissions Units Specific Conditions
- Section IV. Appendices

 2/8/05
Michael G. Cooke, Director (Date)
Division of Air Resources Management

"More Protection, Less Process"

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SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The existing Turkey Point Fossil Plant currently consists of two fossil fuel-fired steam electrical generating units and five “Black Start” diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The proposed “4 on 1” combined cycle Unit 5, which will consist of four gas turbines (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. New combined cycle Unit 5 will have a total generating capacity of approximately 1150 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
005	Unit 5A gas turbine (170 MW) with supplementary-fired heat recovery steam generator
006	Unit 5B gas turbine (170 MW) with supplementary-fired heat recovery steam generator
007	Unit 5C gas turbine (170 MW) with supplementary-fired heat recovery steam generator
008	Unit 5D gas turbine (170 MW) with supplementary-fired heat recovery steam generator
009	One distillate fuel oil storage tank for Unit 5 gas turbines
010	Mechanical draft cooling tower for Unit 5

Note: FPL Turkey Point Fossil Plant Unit 5 consists of four gas combustion turbine-electrical generator sets (Units 5A-5D), four supplementary gas-fired heat recovery steam generators (HRSGs), and a single steam turbine-electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY of this permit).

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as “attainment,” “maintenance,” or “unclassifiable” for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a “fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input”, which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

SECTION I. GENERAL INFORMATION

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Miami-Dade County Department of Environmental Resources Management (DERM), Air Quality Management, 33 Southwest 2nd Avenue, Suite 900, Miami, Florida 33130-1540.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix CF. Citation Format and Definitions

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

Appendix YYYY. NESHAP Requirements for Gas Turbines from 40 CFR 63, Subpart YYYY

Appendix XS. Semiannual NSPS Excess Emissions Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on November 14, 2003;
- Department PSD Application Sufficiency comments dated January 2, 2004;
- Environmental Protection Agency Region 4 letter dated January 15, 2004;
- Department of Interior/NPS letter dated February 27, 2004;
- Sufficiency Responses received March 1, 2004;
- Letter dated April 19, 2004 from Golder in response to NPS letter dated February 27, 2004;
- Draft permit package issued on May 28, 2004;
- Letter dated July 1, 2004 from FP&L regarding draft permit;
- Letter dated July 2, 2004 from National Park Service regarding draft permit;
- Letter dated July 8, 2004 from EPA regarding draft permit;
- Final Certification by the Power Plant Siting Board on February 1, 2005; and
- Final Determination on PSD Permit distributed concurrently with Final PSD Permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]
4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]
6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]
7. Title V Permit Revision: The permittee shall submit an application for a revised Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

This section of the permit addresses the following emissions units.

Emissions Units 005, 006, 007, 008

Description: Emissions units 005, 006, 007, and 008 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate supplementary-fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a generating capacity of 470 MW. The total generating capacity of the "4 on 1" combined cycle unit is approximately 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, PM/PM₁₀, SAM, SO₂ and VOC. Dry Low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system further reduces NO_x emissions.

Stack Parameters: Each HRSG has a stack at least 130 feet tall with a nominal diameter of 19 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics:

<u>Fuel</u>	<u>Heat Input Rate (LHV)</u>	<u>Compressor Inlet Temp.</u>	<u>Exhaust Temp., °F</u>	<u>Flow Rate ACFM</u>
Gas	1,608 MMBtu/hour	59° F	202° F	1,023,872
Oil	1,830 MMBtu/hour	59° F	295° F	1,224,407

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. **BACT Determinations:** Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfuric acid mist (SAM), sulfur dioxide (SO₂) and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
2. **NSPS Requirements:** The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]
- 2.a. **NESHAP Requirements:** The combustion turbines are subject to 40 CFR 63, Subpart YYYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYYY until EPA takes final action to require compliance and publishes a document in the Federal Register.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize the “hot nozzle” DLN combustors, which require natural gas to be preheated to 290 °F before combustion to increase overall unit efficiency. This will be accomplished by feedwater heat exchangers. [Application; Design]
4. Gas Turbine NO_x Controls
 - a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer’s recommendations.
 - b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_x emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer’s recommendations.
 - c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH₃) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_x and NH₃ emissions.
 - d. *Ammonia Storage*: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Design; Rule 62-212.400(BACT), F.A.C.]
5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (5A-5D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_x/MMBtu. {*Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.*} [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,608 MMBtu per hour when firing natural gas and 1,830 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]
8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
 - a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
 - b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any calendar year.
 - c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
 - d. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."
 - e. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.
 - f. *High Power Modes (Peaking and Power Augmentation)*: When firing natural gas and only while practicing duct firing, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. When firing natural gas and only while practicing duct firing, steam may be injected into each gas turbine expansion section to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation," the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total hours of power augmentation plus the total hours of peaking shall not exceed 400 hours per gas turbine during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.0, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12-month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- a. Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
- b. Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission-rates are defined as oxides of nitrogen expressed as NO₂. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

- c. The sulfur fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard and Section 24.41.1 of the Miami-Dade County Code shall be demonstrated by conducting tests in accordance with EPA Method 9.
- d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section. Compliance with the SO₂ BACT also insures compliance with Section 24.41.3 of the Miami-Dade County Code.
- e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- f. Each SCR system shall be designed and operated for ammonia slip limit of no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "PK" means peaking, "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

[Rule 62-212.400(BACT), F.A.C.]

- 10. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. This is not considered a separate mode of operation with respect to emission limits. When operating in this manner, each unit shall comply with the respective standards given in Condition 9 for each mode of operation indicated therein. [Application]
- 11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. *{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da}* [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

- 12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]
14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]
15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A “documented malfunction” means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.
 - a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold “startup of the steam turbine system” is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*
 - b. For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.
 - c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. “Cold startup of a gas turbine/HRSG system” is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.
 - d. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]
16. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer’s specifications. A “major tuning session” would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS PERFORMANCE TESTING

17. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "<http://www.epa.gov/ttn/emc/ctm.html>". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

18. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_x, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Stack test data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_x mass rate emissions standards. CO and NO_x emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]
19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_x limits for each method of operation given in Condition 9 above. [Rule 62-212.400 (BACT), F.A.C.]
20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

21. **CEM Systems:** The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_x from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_x standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
- CO Monitors.** The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - NO_x Monitors.** Each NO_x monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NO_x monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - Diluent Monitors.** The oxygen (O₂) or carbon dioxide (CO₂) content of the flue gas shall be monitored at the location where CO and NO_x are monitored to correct the measured emissions rates to 15% oxygen. If a CO₂ monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
 - 1-Hour Block Averages.** Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0%

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_x as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

- e. *24-hour Block Averages:* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_x emissions depending on the use of alternate methods of operation}.* [Rule 62-212.400(BACT), F.A.C.]
- f. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- g. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

- 22. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_x emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_x monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

RECORDS AND REPORTS

23. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
24. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
25. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.
- Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.
 - Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.
- The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]
26. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

27. Quarterly Excess Emission Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards (BACT, SIP, NSPS) following the NSPS format provided in Appendix XS of this permit.

For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NO_x concentration exceeds the NSPS NO_x emission standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown.

Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7, and 60.334(j)(1)]

28. Semiannual NSPS Excess Emissions Report: The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
009	One distillate fuel oil storage tank for Unit 5 gas turbines (approximately 4.2 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.; and Section 24.41.6, Miami-Dade County Code.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 4.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 5 gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. COOLING TOWER (EU 010)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
010	22-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 22-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM₁₀ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM₁₀ per year. Actual emissions are expected be lower than these rates.}* [Rule 62-212.400(BACT), F.A.C.]

SECTION IV. APPENDICES

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Appendix A	NSPS Subpart A, Identification of General Provisions
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix CF	Citation Format and Definitions
Appendix Da	NSPS Subpart Da Requirements for Duct Burners
Appendix GC	General Conditions
Appendix GG	NSPS Subpart GG Requirements for Gas Turbines
Appendix SC	Standard Conditions
Appendix XS	Semiannual NSPS Excess Emissions Report
Appendix YYYY	NESHAP Requirements for Gas Turbines from 40 CFR 63, Subpart YYYY

SECTION IV. APPENDIX A

NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

- § 60.1 Applicability.
- § 60.2 Definitions.
- § 60.3 Units and abbreviations.
- § 60.4 Address.
- § 60.5 Determination of construction or modification.
- § 60.6 Review of plans.
- § 60.7 Notification and Record Keeping.
- § 60.8 Performance Tests.
- § 60.9 Availability of information.
- § 60.10 State Authority.
- § 60.11 Compliance with Standards and Maintenance Requirements.
- § 60.12 Circumvention.
- § 60.13 Monitoring Requirements.
- § 60.14 Modification.
- § 60.15 Reconstruction.
- § 60.16 Priority List.
- § 60.17 Incorporations by Reference.
- § 60.18 General Control Device Requirements.
- § 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

SECTION IV. APPENDIX BD

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12 month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.
- Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂.
- The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
- The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
- Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

SECTION IV. APPENDIX BD
FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

AA Linero 2/1/05

Recommended By:

Approved By:

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Michael G. Cooke

Michael G. Cooke, Director
Division of Air Resources Management

2/8/05
Date

2/8/05
Date

SECTION IV. APPENDIX CF
CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001" identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

- (119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.
- (179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
- (258) Shutdown - The cessation of the operation of an emissions unit for any purpose.
- (275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 5 gas turbine/HRSG systems, which are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

“Duct burner” means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

“Electric utility combined cycle gas turbine” means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Electric utility steam generating unit” means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Fossil fuel” means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

“Gross output” means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

“Potential electrical output capacity” is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

“Steam generating unit” means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM₁₀ emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil ($\leq 0.05\%$ sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO_2 emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NO_x) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})] / (O_{sg} \times h) \quad (\text{Equation 1})$$

Where:

- E = Emission rate of NO_x from the duct burner, ng/J (lb/Mwh) gross output
- C_{sg} = Average hourly concentration of NO_x exiting the steam generating unit, ng/dscm (lb/dscf)
- C_{te} = Average hourly concentration of NO_x in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
- Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
- Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
- O_{sg} = Average hourly gross energy output from steam generating unit, J (Mwh)
- h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_x concentrations (C_{sg} and C_{te}). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Q_{sg} and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1-hour runs) for the initial performance tests. Thereafter, compliance with the NO_x limits established in the PSD permit shall demonstrate compliance with NO_x limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_x standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_x emission rate when demonstrating compliance with the NO_x standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

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GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
 - a. Have access to and copy and records that must be kept under the conditions of the permit;
 - b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
 - c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
 - a. A description of and cause of non-compliance; and
 - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
 - a. Determination of Best Available Control Technology (X);
 - b. Determination of Prevention of Significant Deterioration (X);
 - c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
 - d. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
 - a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - c. Records of monitoring information shall include:
 - 1) The date, exact place, and time of sampling or measurements;
 - 2) The person responsible for performing the sampling or measurements;
 - 3) The dates analyses were performed;
 - 4) The person responsible for performing the analyses;
 - 5) The analytical techniques or methods used; and
 - 6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SECTION IV. APPENDIX GG
NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The Unit 5 gas turbines are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.330 Applicability and Designation of Affected Facility.

Each Unit 5 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

- (a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.
- (b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.
- (d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.
- (g) ISO standard day conditions mean 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.
- (h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.
- (i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.
- (j) Base load means the load level at which a gas turbine is normally operated.
- (q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_x) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

$$\text{STD} = 0.0075 \frac{(14.4)}{Y} + F$$

Where:

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NO_x contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NO_x emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NO_x standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

SECTION IV. APPENDIX GG
NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil ($\leq 0.05\%$ sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_x standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NO_x emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_x) for each run using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) (\text{Pr}/\text{Po})^{0.5} e^{19(\text{Ho}-0.00633)} (288^\circ\text{K}/\text{Ta})^{1.53}$$

Where:

- NO_x = Emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, volume percent
- NO_{x0} = Observed NO_x concentration, ppm by volume
- Pr = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
- Po = Observed combustor inlet absolute pressure at test, mm Hg
- Ho = Observed humidity of ambient air, g H_2O /g air
- e = Transcendental constant, 2.718
- Ta = Ambient temperature, $^\circ\text{K}$

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_x monitor shall be used to demonstrate compliance with the specified NO_x limits. The permittee is allowed to make the initial compliance demonstration for NO_x emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_x monitor. The permittee is not required to have the NO_x monitor continuously correct NO_x emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

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STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

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STANDARD CONDITIONS

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]
12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
 - a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
 - b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
 - c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.[Rule 62-297.310(4), F.A.C.]
14. Determination of Process Variables
 - a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
 - b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.[Rule 62-297.310(5), F.A.C.]
15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.
16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]
17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]
18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

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sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

- 1) The type, location, and designation of the emissions unit tested.
- 2) The facility at which the emissions unit is located.
- 3) The owner or operator of the emissions unit.
- 4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
- 5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
- 6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
- 7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
- 8) The date, starting time and duration of each sampling run.
- 9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
- 10) The number of points sampled and configuration and location of the sampling plane.
- 11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
- 12) The type, manufacturer and configuration of the sampling equipment used.
- 13) Data related to the required calibration of the test equipment.
- 14) Data on the identification, processing and weights of all filters used.
- 15) Data on the types and amounts of any chemical solutions used.
- 16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
- 17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
- 18) All measured and calculated data required to be determined by each applicable test procedure for each run.
- 19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
- 20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
- 21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION IV. APPENDIX XS
SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

**FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING
SYSTEM PERFORMANCE**

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant (*Circle One*): SO₂ NO_x TRS H₂S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ¹: _____

Emission data summary ¹	CMS performance summary ¹
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. Total duration of excess emissions x (100) / [Total source operating time] % ²	1. CMS downtime in reporting period due to: a. Monitor equipment malfunctions b. Non-Monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CMS Downtime 3. [Total CMS Downtime] x (100) / [Total source operating time] % ²

¹ For opacity, record all times in minutes. For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ Date: _____

Title: _____

SECTION IV. APPENDIX YYYY
NESHAP REQUIREMENTS FOR GAS TURBINES

Applicability of NESHAP Subpart YYYY

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O₂). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

According to General Electric, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposed to meet the limit proposed in YYYY of 91 ppbvd based on the performance of the GE 7FA unit. The very low CO and VOC emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_x combustion technology employed by these units ensure that formaldehyde emissions will be at the lowest end of the spectrum.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY at the time this permit was issued (February 2005) were:

§ 63.6145 What notifications must I submit and when?

- (a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.
- (b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.
- (c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.
- (d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).
- (e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).
- (f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

Article Addressed to:

Mr. H.O. Nunez, Plant General Manager
Florida Power and Light Company,
Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

Article Number

(Transfer from service label)

7000 1670 0013 3110 2325

PS Form 3811, August 2001

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A. Signature

[Signature] ☒ Agent
☐ Addressee

B. Received by (Printed Name)

SECURITY

C. Date of Delivery

2/12/5

D. Is delivery address different from item 1? ☒ YesIf YES, enter delivery address below: ☐ No

3. Service Type

- ☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Randall R. LaBauve
Vice President
Environmental Services
Flower Power & Light
700 Universe Blvd.
Juno Beach, Florida 33408

2. Article Number

(Transfer from service label)

PS Form 3811, August 2001

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A. Signature

X *[Signature]* ☒ Agent
☐ Addressee

B. Received by (Printed Name)

G. ADAMS

C. Date of Delivery

2-11-5

D. Is delivery address different from item 1? ☐ YesIf YES, enter delivery address below: ☐ No

3. Service Type

- ☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 2325

Postage	\$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total P	

Postmark
Here

Sent To

Street, A

City, Sta

PS Form 3800, May 2001

Mr. H.O. Nunez, Plant General Manager
Florida Power and Light Company,
Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 2318

Postage	\$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark
Here

Mr. Randall R. LaBauve
Vice President
Environmental Services
Flower Power & Light
700 Universe Blvd.
Juno Beach, Florida 33408

Memorandum

Florida Department of Environmental Protection

TO: Michael G. Cooke, Director DARM
TO: Trina L. Vielhauer, Chief BAR
FROM: A.A. Linero, P.E., Program Administrator, South Permitting Section 
DATE: February 1, 2005
SUBJECT: FPL Turkey Point 1,150 MW Expansion Project
DEP File No. 0250003-006-AC (PSD-FL-338)

Attached is the Final PSD Permit for FPL Turkey Point Power Plant Unit 5. The project consists of a "four on one" gas-fired combined cycle base load unit with a total capacity of 1,150 megawatts. The site is located near the Class I Everglades National Park and is adjacent to the Class II Biscayne National Park.

Each Heat Recovery Steam Generator will be equipped with a large duct burner for supplemental firing to boost steam production.

Nitrogen Oxides (NO_x) emissions will be controlled by SCR to 2.0 parts per million at 15 percent oxygen (ppmvd @15%O₂) on a 24-hr basis when firing natural gas. This is the lowest value yet in the Southeast. Emissions when firing fuel oil will be 8 ppmvd@15% O₂.

Carbon monoxide (CO) will be controlled to 4.1 and 8.0 ppmvd @15% O₂ when burning natural gas and fuel oil respectively. These are the lowest values yet for projects without the use of oxidation catalyst. Working with FP&L we were able to get GE to guarantee these limits for the first time that I am aware of. There are allowances for the duct burners when used, and power augmentation (steam injection) and peaking. Although the 24-hr limit of 8.0 ppm reflects the possibility of operation in high power modes for an entire day, the 12-month limit of 6 ppm more accurately reflects the long term mix of modes.

VOC, SO₂, sulfuric acid mist and particulate matter emissions will be inherently low due to the use of inherently clean fuels. FP&L has committed to use ultra low sulfur (0.0015% S) fuel oil for backup purposes 500 hours per year per unit. We have set an ammonia limit of 5 ppmvd @15% O₂. This not only minimizes particulate formation, but also reduces nitrogen deposition in the Everglades NPS.

There was considerable consultation over the past year with the NPS. They submitted commented on the application. We concluded that the project will not cause or contribute to violations of the ambient air quality standards or the Class I increments and that there will be no adverse impacts on air quality related values (AQRVs) such as visibility. Our qualitative and semi-quantitative analysis suggests that there has been expansion of SO₂ increment since 1977 and that the proposed project will not affect that expansion.

No comments were received from the public. Those received from NPS, EPA, and FP&L were discussed and are addressed in the attached Final Determination to Issue a PSD Permit.

The Siting Board granted certification on February 1. I recommend your approval of the final PSD Permit as soon we receive our copy of the signed Certification Order.

AAL/aal

Attachments



FPL

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

June 16, 2004

Trina L. Vielhauer, Chief
Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED

JUN 17 2004

BUREAU OF AIR REGULATION

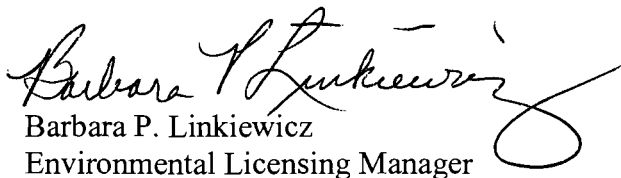
RE: FPL Turkey Point Fossil Plant
DEP File No. 0250003-006-AC (PSD-FL-338)
1150 MW Combined Cycle Unit No. 5

Dear Ms. Vielhauer:

The Public Notice was published in the Thursday, June 10th edition of the Miami Herald. This is a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. The enclosed proof of publication, (i.e., newspaper affidavit) is being provided to the Department's Bureau of Air Regulation office within seven (7) days of publication.

If you have any questions regarding this matter, please feel free to contact me at (561) 691-7518.

Thank you,


Barbara P. Linkiewicz
Environmental Licensing Manager

BPL/sap

Enclosures: Miami Herald affidavit

cc: HGS – Peter Cunningham

FPL – Ed Nunez

FPL – John Gnecco

A. Giner

D. Nelson

J. Little SED

P. Wong, DERM

D. Worley, EPA

G. Bursch, NPS

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www.elherald.com

**PUBLISHED DAILY
MIAMI-DADE-FLORIDA**

STATE OF FLORIDA
COUNTY OF MIAMI-DADE

Before the undersigned authority personally appeared:

JEANNETTE MARTINEZ

who on oath says that he/she is

CUSTODIAN OF RECORDS

of The Miami Herald, a daily newspaper published at Miami in Miami-Dade County, Florida; that the attached copy of advertisement was published in said newspaper in the issues of:

June 10, 2004

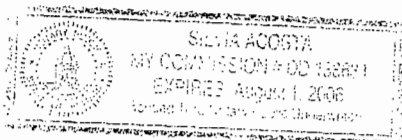
Affiant further says that the said The Miami Herald is a newspaper published at Miami, in the said Miami-Dade County, Florida and that the said newspaper has heretofore been continuously published in said Miami-Dade County, Florida each day and has been entered as second class mail matter at the post office in Miami, in said Miami-Dade County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper(s).

Sworn to and subscribed before me this
15th day of June 2004

My Commission

Expires: August 1, 2006
Silvia Acosta

Notary



PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0250003-006-AC (PSD-FL-338)

FPL Turkey Point Fossil Plant, New Combined Cycle Unit 5
Miami-Dade County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Air Quality to the Florida Power & Light Company. The permit is one of several authorizations needed to construct a nominal 1,150 MW existing Turkey Point Fossil Plant east of Homestead and Florida City, and adjacent to Biscayne Bay in Miami-Dade County. A determination (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO), nitrogen dioxide (NO₂), sulfur dioxide (SO₂), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's corporate address is Florida Power & Light Company, 1700 N.W. 8th Avenue, Suite 1900, Fort Lauderdale, FL 33311. The project location is at 1300 S.W. 1st Avenue, Juno Beach, Florida 33408.

The applicant proposes to construct a new electrical power generating unit (Unit 5). The primary components are: four combustion fired heat recovery steam generators (HRSGs); a single steam-electrical generator; a 22-cell mechanical draft cooling tower; four exhaust storage tank; and other associated support equipment.

Unit 5 will be permitted to operate continuously while firing inherently clean natural gas. Ultra low sulfur (0.0015 percent sulfur) distillate will be allowed as backup fuel for 500 hours per year per combustion turbine. Steam injection (augmentation) and firing of natural gas in the duct burners located within the HRSGs (supplemental firing) will be allowed for limited

A selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with Dry Low-NO_x combustion (gas emissions). The proposed NO_x emission limit of 2.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O₂), most protective standard for any project authorized to date in the Southeastern United States. Sufficient catalyst will be used to minimize proposed NO_x limit while firing ultra low sulfur fuel oil is 8 ppmvd @15% O₂. The proposed CO emission limits of 4.1 and 8.0 ppmv: respectively represent the lowest values guaranteed to-date without requiring oxidation catalyst. Typical CO emissions will actually modes.

Emissions of CO, PM/PM₁₀, SAM, SO₂, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean continuously monitored to demonstrate compliance with the conditions of the permit. The complete set of proposed emission limits Miami-Dade County DERM office and website addresses indicated below.

The applicant's estimate of maximum potential annual emissions from Unit 5 are summarized in the following table.

<u>Pollutant</u>	<u>Maximum Tons Per Year</u>	<u>PSD Significant Emission Rate Tons Per Year</u>
CO	464	100
Pb	0.026	0.6
NO _x	312	40
PM/PM ₁₀	420/229	25/15
SO ₂	193	40
SAM	19	7
VOC	68	40

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than 1% outside of the Everglades National Park (i.e., PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air predicted impacts in the Class I Everglades National Park (ENP) are less than the applicable significant impact levels except for the impacts. Therefore multi-source increment modeling was required for the 3-hour and 24-hour SO₂ and 24-hour PM₁₀ impacts; the maximum predicted 3-hour and 24-hour SO₂ and 24-hour PM₁₀ increment consumption by the new project and by all projects in the

Averaging Time	PM ₁₀ Increment Consumed in ug/m ³ and % at ENP		SO ₂ Increment Cc	
	By Project	All Sources	By Project	All Sources
24-hour	0.5 (10% of Allowable)	2.1 (42% of Allowable)	0.4 (8% of Allowable)	2.1 (42% of Allowable)
3-hour	No Analysis Required	No Analysis Required	2 (8% of Allowable)	2.1 (42% of Allowable)

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly standard or PSD increment. A small impact on air quality related values (visibility) was projected to occur approximately 2 days in fired, instead of natural gas, and the ambient temperature is 35 degrees F. Because fuel oil will be used less than 10 percent of the South Florida coastline, the coincidence of the factors that promote visibility impact is minimal. The probability of such an occi-

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in a different decision is significant change of terms or conditions. The Department will accept written comments and requests to issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32304. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed prior to the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is subject to the Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed, it shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this process.

[illegible]

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) a statement of the agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the agency, and the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of the basis for the agency's determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of the facts alleged to be material facts, if there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the facts alleged to be material facts; (f) A statement of the specific rules or statutes the petitioner contends require the agency to take the action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to mean that the Department's final action may be different from the position taken by it in this notice, persons whose substantiality of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the regulations.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday.

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32309-2400

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, FL 33416-5125

ISHED DAILY
II-DADE-FLORIDA

E OF FLORIDA
NTY OF MIAMI-DADE

the undersigned authority personally
ed:

JEANNETTE MARTINEZ

oath says that he/she is

USTODIAN OF RECORDS

Miami Herald, a daily newspaper published at
in Miami-Dade County, Florida; that the
d copy of advertisement was published in said
per in the issues of:

June 10, 2004

further says that the said The Miami Herald
spaper published at Miami, in the said
Dade County, Florida and that the said
er has heretofore been continuously published
Miami-Dade County, Florida each day and has
tered as second class mail matter at the post
Miami, in said Miami-Dade County, Florida,
iod of one year next preceding the first
ion of the attached copy of advertisement;
nt further says that he has neither paid nor
d any person, firm or corporation any discount,
ommission or refund for the purpose of
this advertisement for publication in the said
ers(s).

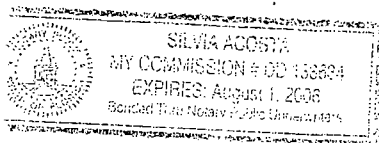
Jeannette Martinez
and subscribed before me this
day of June 2004

mission

August 1, 2006

Silvia Acosta

Silvia Acosta
Notary



PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0250003-006-AC (PSD-FL-338)

FPL Turkey Point Fossil Plant, New Combined Cycle Unit 5
Miami-Dade County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power & Light Company. The permit is one of several authorizations needed to construct a nominal 1,150 MW combined cycle natural gas-fired unit at the existing Turkey Point Fossil Plant east of Homestead and Florida City, and adjacent to Biscayne Bay in Miami-Dade County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfur dioxide (SO2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's corporate address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

The applicant proposes to construct a new electrical power generating unit (Unit 5). The primary components are: four combustion turbine-electrical generators; four supplementary-fired heat recovery steam generators (HRSGs); a single steam-electrical generator; a 22-cell mechanical draft cooling tower; four exhaust stacks; a 4.3 million gallon diesel fuel storage tank; and other associated support equipment.

Unit 5 will be permitted to operate continuously while firing inherently clean natural gas. Ultra low sulfur (0.0015 percent sulfur) distillate fuel oil will be available in Southeast Florida by the time the project starts up. Its use will be allowed as backup fuel for 500 hours per year per combustion turbine. Steam injection into the combustion turbines (power augmentation) and firing of natural gas in the duct burners located within the HRSGs (supplemental firing) will be allowed for limited periods of time to meet peak power demand.

A selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with Dry Low-NOx combustion (gas firing) and wet injection (oil firing) to control NOx emissions. The proposed NOx emission limit of 2.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmv @15% O2) of NOx while firing natural gas represents the most protective standard for any project authorized to date in the Southeastern United States. Sufficient catalyst will be used to minimize emissions of ammonia reagent. The proposed NOx limit while firing ultra low sulfur fuel oil is 8 ppmv @15% O2. The proposed CO emission limits of 4.1 and 8.0 ppmv @15% O2 while burning gas and oil respectively represent the lowest values guaranteed to-date without requiring oxidation catalyst. Typical CO emissions will actually be 2 ppmv or less under most operational modes.

Emissions of CO, PM/PM10, SAM, SO2, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean fuels. Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. The complete set of proposed emission limits is available at the Department offices, the local Miami-Dade County DEPM office and website addresses indicated below.

The applicant's estimate of maximum potential annual emissions from Unit 5 are summarized in the following table.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	464	100	Yes
Pb	0.026	0.6	No
NOx	312	40	Yes
PM/PM10	420/229	25/15	Yes
SO2	193	40	Yes
SAM	19	7	Yes
VOC	68	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards Class II increments. The predicted impacts in the Class I Everglades National Park (ENP) are less than the applicable significant impact levels except for the 3-hour and 24-hour SO2 and 24-hour PM10 impacts. Therefore multi-source increment modeling was required for the 3-hour and 24-hour SO2 and 24-hour PM10 impacts upon the ENP. The following table summarizes the maximum predicted 3-hour and 24-hour SO2 and 24-hour PM10 increment consumption by the new project and by all project in the general area since 1977.

Averaging Time	PM10 Increment Consumed in ug/m ³ and % at ENP		SO2 Increment Consumed in ug/m ³ and % at ENP	
	By Project	All Sources	By Project	All Sources
24-hour	0.5 (10% of Allowable)	2.1 (42% of Allowable)	0.4 (8% of Allowable)	4.1 (82% of Allowable)
3-hour	No Analysis Required	No Analysis Required	2 (8% of Allowable)	18 (72% of Allowable)

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. A small impact on air quality related values (visibility) was projected to occur approximately 2 days in three years if ultra low sulfur fuel oil is continuously fired, instead of natural gas, and the ambient temperature is 35 degrees F. Because fuel oil will be used less than 10 percent of the time and such low temperatures are atypical for the South Florida coastline, the coincidence of the factors that promote visibility impact is minimal. The probability of such an occurrence is less than one every three years.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact, if there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

Miami-Dade Department of
Environmental Resource Management
33 SW 2nd Avenue, Suite 900
Miami, Florida 33130-1540
Telephone: 305/372-6925
Fax: 305/372-6954

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact A. A. Linero or Debbie Nelson of the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. Address e-mail comments to alvaro.linero@dep.state.fl.us. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/air/permitting/construction/turkeypoint.htm.



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

JUL 8 2004

RECEIVED

JUL 14 2004

4APT-APB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

BUREAU OF AIR REGULATION

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for Florida Power & Light (FPL) Turkey Point, dated May 28, 2004. The draft PSD permit is for the proposed construction and operation of four combined cycle combustion turbines (CTs) with a total nominal generating capacity of 1,150 MW to be located near Homstead, FL. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with ultra low sulfur fuel oil (0.0015% S) combusted as backup fuel. As proposed, the CTs will be allowed to operate in the following manner: to fire natural gas up to 8,760 hours per year per CT, to fire fuel oil a maximum of 500 hours per year per CT, to operate in power augmentation mode up to 400 hours per year per CT, and to operate natural gas-fired duct burners up to a total of 5,702,400 MMBtu per year for all four CTs combined. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO₂), particulate matter (PM/PM₁₀), and volatile organic compounds (VOC).

Based on our review of the preliminary determination, draft PSD permit, and FP&L's response to comments document, we have the following comments:

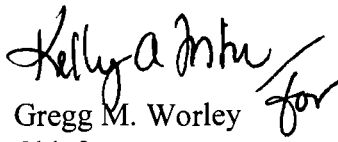
1. Condition 9 of the draft PSD permit contains a table of CO emissions limits that are applicable to various operating modes of the four new CTs. The table contains two columns of emission limits. Compliance with the first column of emission limits shall be demonstrated by 3-run stack testing, while compliance with the second column of emission limits shall be demonstrated using a continuous emissions monitoring system (CEMS) with a 24-hour averaging time. It is our understanding from conversations with the Florida Department of Environmental Protection (FDEP) that the first column of CO emission limits represents the BACT emission limits (i.e., 4.1 ppm in normal mode, 7.6 ppm with duct burning, etc.) and the second column of CO emission limits contains higher limits that have been proposed to simplify the recordkeeping process (i.e., 8.0 ppm for all modes except power augmentation, etc.).

First, we would like to point out that the distinction between the two sets of emission limits described above is not clear in the current draft PSD permit. If the emission limits are left as they are, this relationship should be better described in the table itself or in a permitting note immediately **preceding** the table. Second, we agree with FDEP that initial compliance with the BACT limits can be determined using a stack test; however, continuous compliance with the BACT emission limits should be demonstrated by use of the CEMS. Condition 19 of the draft PSD permit declares that FDEP "reserves the right" to use data from the CEMS to determine compliance with the short-term CO emission limits. We believe that this condition is not definite enough to enforce the BACT emission limits using CEMS. Finally, if it is decided that the CEMS will be used to determine compliance with the BACT emission limits, we recommend that the final PSD permit require use of an averaging time shorter than 24 hours. Since there exist short-term CO national ambient air quality standards (NAAQS) with averaging times below 24 hours (i.e., 1-hour and 8-hour standards), we believe that the averaging times should be more consistent with the applicable NAAQS averaging times.

2. As we mentioned in our comment letter dated January 15, 2004, any operating limits which were used in the analyses on a per turbine basis should be included in the draft PSD permit on a per turbine basis. The draft PSD permit does contain per turbine limits on the amount of time the CTs can operate in power augmentation mode and while firing fuel oil. However, condition 8(e) of the draft PSD permit contains one aggregate limit (5,702,400 MMBtu) for all four CTs restricting the amount of duct firing that is allowed in a year. In order for the BACT analysis to remain valid, the final PSD permit should contain the appropriate duct firing limit on a per turbine basis (i.e., 1,425,600 MMBtu/year). Alternatively, if the applicant wishes to retain the aggregate limit, a revised BACT analysis should be performed (based on the worst case scenario of one CT operating the duct burners all year long) which demonstrates that the outcome of the BACT analysis would remain unchanged.

If you have any questions regarding these comments or need additional information, please contact Katy Forney at 404-562-9130.

Sincerely,


Gregg M. Worley
Chief
Air Permits Section



IN REPLY REFER TO:

United States Department of the Interior

NATIONAL PARK SERVICE

Air Resources Division

P.O. Box 25287

Denver, CO 80225

RECEIVED

JUL 07 2004

BUREAU OF AIR REGULATION

July 2, 2004

N3615 (2350)

A.A. Linero, P.E., Administrator
Department for Environmental Protection
New Source Review Section
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

We have reviewed the Florida Power & Light's (FP&L) Turkey Point Power Plant Prevention of Significant Deterioration (PSD) final draft permit and Florida Department for Environmental Protection's (FDEP) Technical Evaluation and Preliminary Determination (TEPD). FP&L proposes to construct a "4-on-1" combined cycle unit (Unit 5) consisting of four 170 MW gas turbine-electrical generators; four gas-fired heat recovery steam generators; and a single steam turbine with associated electric generator and a cooling tower. The proposed increase in emission levels identified in the TEPD are 312 tons per year (TYP) of nitrogen oxides (NO_x), 320 TPY of particulate matter, 224 TPY of particulate matter less than 10 microns in size (PM_{10}), 193 TPY of sulfur dioxide (SO_2), 68 TPY of volatile organic pollutants, and 19 TPY of sulfuric acid mist. The Turkey Point Power Plant is located 21 kilometers east of Everglades National Park (NP) and adjacent to Biscayne NP. Everglades NP is a Class I air quality area and Biscayne NP is a Class II air quality area, both areas are administered by the National Park Service (NPS).

As shown in the TEPD, FP&L will reduce their NO_x limit from 2.5 ppm (as proposed in their original PSD permit application) to 2.0 ppm when burning natural gas and from 10.0 ppm to 8.0 ppm when burning fuel oil. The TEPD also shows the estimated NO_x emissions will be reduced from 387 TPY (as originally identified in their PSD permit application) to 312 TPY. When fuel oil is used and limited to 500 hours for a 12 month period, results from the FP&L visibility modeling analysis (including the new NO_x limits and lower emissions), show impacts at Everglades NP will be limited to two days slightly over a 5% change in extinction during the three years modeled. There will be no visibility impacts over a 5% change in extinction at Everglades NP when the facility is burning natural gas. At the lower NO_x emission rates, we anticipate that visibility impacts at Biscayne NP will also be reduced. Therefore, we do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will adversely

impact sensitive resources at Everglades NP or Biscayne NP. However, as discussed below, we are concerned that FP&L may not have adequately assessed potential impacts during the High Power Operating Mode. We have the following comments regarding Best Available Control Technology (BACT) for the facility, and the air quality modeling analysis.

BACT Analysis

FP&L proposes to construct and operate four General Electric (GE) 7FA combustion turbines and associated electric generators. FP&L proposes to use Selective Catalytic Reduction (SCR) with a limit of 2.0 ppm NO_x when burning natural gas, and 8.0 ppm NO_x when burning oil. These limits would be enforced over a 24-hour averaging period. While we commend FP&L for reducing its NO_x emission limits from those originally proposed, we believe FDEP should require a shorter averaging period for the NO_x emission limit.

BACT is defined as:

an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant...

It is important to note that BACT is an emission limit, and emission limits typically consist of a numerical limit in terms of mass of pollutant per unit time (e.g., lb/hr), unit volume (e.g. ppmvd) and/or per unit of heat input (e.g., lb/mmBtu). These emission limits are also typically specified over a prescribed averaging period; due to the inherent variability in emissions and the performance of the control technology, the longer the averaging period, the easier it is to meet a given limit.

Although it states in the TEPD top-down analysis that "The 'Top' emission limit is considered by the department to be 2.0 ppmvd @ 15% O₂ on a 1-hour average," FDEP goes on to set FP&L's proposed permit limit for natural gas combustion based upon a 24-hour average, with no explanation provided for the longer averaging period. Therefore, FDEP did not choose the "top" control technology, nor did it justify proposing a less stringent limit.

We believe that the 24-hour block averaging periods are much too long when compared to similar combustion turbines meeting the same outlet concentration limits for one-hour or three-hour averages. The effect of the much longer averaging periods is to reduce the stringency of the limits relative to other permits. For example, Clark County, Nevada, has determined that a 2.0 ppm limit (1-hr average) represents BACT for the Diamond Generating, Ivanpah Energy combustion turbine project. The Virginia Department of Environmental Protection has permitted an identical limit for the CPV Warren County

combustion turbine project. Turkey Point should show why it cannot meet a 2.0 ppm limit on a one-hour basis, as is required of other similar projects.

High Power Modes: Although FDEP acknowledges that the high power operating modes "can cause greater uncontrolled NO_x emissions," the proposed permit explicitly exempts FP&L from any emission limits while operating in this mode. Not only does this fail to meet the requirements of New Source Review to establish appropriate limits on emissions during all operation, it could also render the single-source emissions modeling invalid if this "unlimited" emissions during high power mode was not modeled.

Air Quality Modeling Analysis

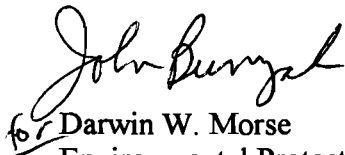
Cumulative Source Modeling: As referenced in our February 24, 2004, letter to FDEP regarding the emission inventories presented in the FP&L permit application, we reiterate that we would like to know how sources were selected for the inventory, and how emissions from those sources were determined.

Conclusions

In conclusion, we request that FDEP require a one-hour averaging period for the proposed NO_x emission limit of 2.0 ppm for natural gas and 8.0 ppm for fuel oil. We also ask that FDEP include an emission limit during the "High Power Modes" and demonstrate that those emissions will not violate applicable National Ambient Air Quality Standards and Class I increments, nor adversely impact Everglades NP. Finally, as stated in our February 24, 2004, letter, we ask that FP&L justify its cumulative increment analysis.

Thank you for involving us in the review of the PSD permit application for the Turkey Point Power Plant. Please do not hesitate to contact me at (303) 969-2817 if you have questions concerning our comments.

Sincerely,



for Darwin W. Morse
Environmental Protection Specialist
Policy, Planning and Permit Review Branch



RECEIVED
JUL 02 2004
BUREAU OF AIR REGULATION

July 1, 2004

A.A. Linero
Program Administrator, South Permitting
Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32399-2400

Re: Florida Power & Light Company
Turkey Point Expansion Project
DEP File No. 0250003-0060AC (PSD-FL-338)

Dear Mr. Linero:

Thank you for taking time to meet with us on Tuesday June 22, 2004. I am writing to respectfully request that you consider the following clarifications to the draft Prevention of Significant Deterioration of Air Quality (PSD) permit issued on May 28, 2004 and public noticed on June 10, 2004. Please note that none of these proposed clarifications have any impact on the air modeling performed to evaluate potential impacts.

In Section III, page 7 of 17, we request the following clarification for operational flexibility:

8. Methods of Operation

b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grams of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. ~~Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months. The four gas turbines shall fire no more than a cumulative total of 28,028,168 gallons of fuel oil during any calendar year.~~

In Section III, page 9 of 17, we request the following clarification to be consistent with the Table in Section IV, Appendix BD, page 1.

9. Emissions Standards

f. Each SCR system shall be designed and operated for ammonia slip limit of less no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

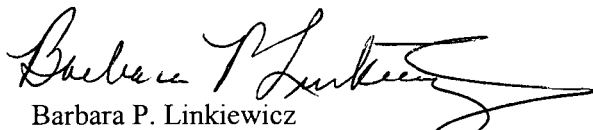
In Section III, pages 14-15 of 17, we request the clarifications below. Recognizing that quarterly reports contain all NSPS and State requirements, this clarification combines the quarterly and semiannual reports. The proposed language below also makes condition 27 consistent with condition 25a regarding the monitoring period.

~~27. Semiannual NSPS Excess Emissions Report. Quarterly Excess Emission Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards w~~ Within 30 days following the end of each calendar-quarter, ~~the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOX emissions in excess of the permit standards following the NSPS format provided in Appendix XS of this permit.~~ For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOX emission standard identified in Appendix GG; and any ~~daily monitoring~~ period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOX or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. ~~An example of the report is provided on Appendix XS. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]~~

28. ~~Quarterly Permit Excess Emissions Report~~ Semiannual NSPS Excess Emissions Report: ~~Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOX emissions in excess of the permit standards. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]~~ The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.

We appreciate your consideration of these proposed clarifications. If you have any questions or require additional information, please contact me at (561) 691-7518.

Sincerely,


Barbara P. Linkiewicz
Environmental Licensing Manager

cc: Stephen Palmer, DEP Siting Coordination Office
Ken Kosky, Golder Associates



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

May 28, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. H. O. Nunez, Plant General Manager
Florida Power & Light Company (FPL)
Turkey Point Fossil Plant
9700 Southwest 344 Street
Homestead, Florida 33035

Re: FPL Turkey Point Fossil Plant
DEP File No. 0250003-006-AC (PSD-FL-338)
1150 MW Combined Cycle Unit No. 5

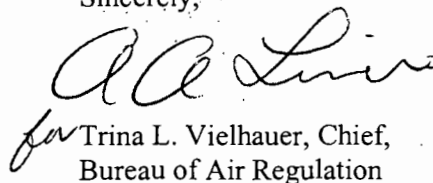
Dear Mr. Nunez:

Enclosed are documents indicating the Department's intent to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to FPL for construction of a 1,150 megawatt combined cycle unit at the Turkey Point Fossil Plant. The documents include: the "Intent to Issue PSD Permit;" the "Public Notice of Intent to Issue PSD Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven (7) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 or Mr. Linero at 850/921-9523.

Sincerely,


for Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/aal

Enclosures

"More Protection, Less Process"

Printed on recycled paper.

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. H. O. Nunez
Plant General Manager
FPL Turkey Point Fossil Plant
9700 Southwest 344 Street
Homestead, FL 33035

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. Date of Delivery

C. Signature

X

☐ Agent☒ AddresseeD. Is delivery address different from item 1? ☐ YesIf YES, enter delivery address below: ☐ No

3. Service Type

☒ Certified Mail☐ Express Mail☐ Registered☐ Return Receipt for Merchandise☐ Insured Mail☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

2. Article Number (Copy from service label)

7099 3220 0003 6189 5273

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

U.S. Postal Service**CERTIFIED MAIL RECEIPT**

(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:

Mr. H. O. Nunez, Plant Manager

Postage

\$

Certified Fee

Return Receipt Fee
(Endorsement Required)Restricted Delivery Fee
(Endorsement Required)

Total Postage & Fees

\$

Postmark
Here

Name (Please Print Clearly) (To be completed by mailer)

FPL Turkey Point Fossil Plant

Street, Apt. No.; or PO Box No.

9700 Southwest 344 Street

City, State, ZIP+4

Homestead, FL 33035

PS Form 3800, July 1999

See Reverse for Instructions

7099 3220 0003 6189 5273

In the Matter of an
Application for Permit by:

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

DEP File No. 0250003-006-AC
Draft Permit No. PSD-FL-338
FPL Turkey Point Fossil Plant
1,150 MW Combined Cycle Unit 5

Authorized Representative:

Mr. H. O. Nunez, Plant General Manager

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, FPL, applied on November 14, 2003 (deemed sufficient on April 7 2004) to the Department for a PSD permit for a 1150 megawatt combined cycle gas turbine project (Unit 5) at the FPL Turkey Point Fossil Plant located east of Homestead and Florida City on Biscayne Bay, Miami-Dade County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit is required.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue PSD Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3).

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

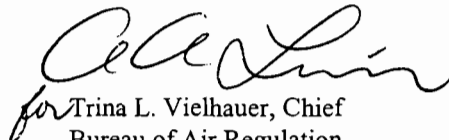
The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each

rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.


for Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

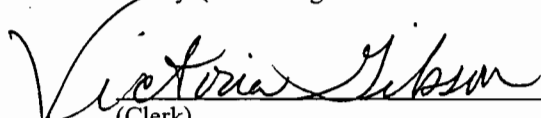
The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/28/04 to the persons listed:

H. O. Nunez, FPL*
Mayor, Miami-Dade County
Mayor, City of Homestead
Mayor, Florida City
John Benjamin, Everglades National Park
Linda Canzanelli, Biscayne National Park
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO

Steven L. Palmer, DEP Siting Office
Tom Tittle, DEP SED
Paul Darst, Department of Community Affairs
Chair, Miami-Dade County EQCB
H. Patrick Wong, Miami-Dade County DERM
Ken Kosky, P.E., Golder
Barbara Linkiewicz, FPL

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.


(Clerk) 5/28/04
(Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0250003-006-AC (PSD-FL-338)

FPL Turkey Point Fossil Plant, New Combined Cycle Unit 5
Miami-Dade County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power & Light Company. The permit is one of several authorizations needed to construct a nominal 1,150 MW combined cycle natural gas-fired unit at the existing Turkey Point Fossil Plant east of Homestead and Florida City, and adjacent to Biscayne Bay in Miami-Dade County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's corporate address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

The applicant proposes to construct a new electrical power generating unit (Unit 5). The primary components are: four combustion turbine-electrical generators; four supplementary-fired heat recovery steam generators (HRSGs); a single steam-electrical generator; a 22-cell mechanical draft cooling tower; four exhaust stacks; a 4.3 million gallon diesel fuel storage tank; and other associated support equipment.

Unit 5 will be permitted to operate continuously while firing inherently clean natural gas. Ultra low sulfur (0.0015 percent sulfur) distillate fuel oil will be available in Southeast Florida by the time the project starts up. Its use will be allowed as backup fuel for 500 hours per year per combustion turbine. Steam injection into the combustion turbines (power augmentation) and firing of natural gas in the duct burners located within the HRSGs (supplemental firing) will be allowed for limited periods of time to meet peak power demand.

A selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with Dry Low-NO_x combustion (gas firing) and wet injection (oil firing) to control NO_x emissions. The proposed NO_x emission limit of 2.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O₂) of NO_x while firing natural gas represents the most protective standard for any project authorized to date in the Southeastern United States. Sufficient catalyst will be used to minimize emissions of ammonia reagent. The proposed NO_x limit while firing ultra low sulfur fuel oil is 8 ppmvd @15% O₂. The proposed CO emission limits of 4.1 and 8.0 ppmvd @15% O₂ while burning gas and oil respectively represent the lowest values guaranteed to-date without requiring oxidation catalyst. Typical CO emissions will actually be 2 ppmvd or less under most operational modes.

Emissions of CO, PM/PM₁₀, SAM, SO₂, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean fuels. Emissions of CO and NO_x will be continuously monitored to demonstrate compliance with the conditions of the permit. The complete set of proposed emission limits is available at the Department offices, the local Miami-Dade County DERM office and website addresses indicated below.

The applicant's estimate of maximum potential annual emissions from Unit 5 are summarized in the following table.

<u>Pollutant</u>	<u>Maximum Tons Per Year</u>	<u>PSD Significant Emission Rate Tons Per Year</u>	<u>PSD Review Required?</u>
CO	464	100	Yes
Pb	0.026	0.6	No
NO _x	312	40	Yes
PM/PM ₁₀	420/229	25/15	Yes
SO ₂	193	40	Yes
SAM	19	7	Yes
VOC	68	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards Class II increments. The predicted impacts in the Class I Everglades National Park (ENP) are less than the applicable significant impact levels except for the 3-hour and 24-hour SO₂ and 24-hour PM₁₀ impacts. Therefore multi-source increment modeling was required for the 3-hour and 24-hour SO₂ and 24-hour PM₁₀ impacts upon the ENP. The following table summarizes the maximum predicted 3-hour and 24-hour SO₂ and 24-hour PM₁₀ increment consumption by the new project and by all project in the general area since 1977.

<u>Averaging Time</u>	<u>PM₁₀ Increment Consumed in ug/m³ and % at ENP</u>		<u>SO₂ Increment Consumed in ug/m³ and % at ENP</u>	
	<u>By Project</u>	<u>All Sources</u>	<u>By Project</u>	<u>All Sources</u>
24-hour	0.5 (10% of Allowable)	2.1 (42% of Allowable)	0.4 (8% of Allowable)	4.1 (82% of Allowable)
3-hour	No Analysis Required	No Analysis Required	2 (8% of Allowable)	18 (72% of Allowable)

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. A small impact on air quality related values (visibility) was projected to occur approximately 2 days in three years if ultra low sulfur fuel oil is continuously fired, instead of natural gas, and the ambient temperature is 35 degrees F. Because fuel oil will be used less than 10 percent of the time and such low temperatures are atypical for the South Florida coastline, the coincidence of the factors that promote visibility impact is minimal. The probability of such an occurrence is less than one every three years.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

Miami-Dade Department of
Environmental Resource Management
33 SW 2nd Avenue, Suite 900
Miami, Florida 33130-1540
Telephone: 305/372-6925
Fax: 305/372-6954

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact A. A. Linero or Debbie Nelson of the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. Address e-mail comments to alvaro.linero@dep.state.fl.us. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/air/permitting/construction/turkeypoint.htm.

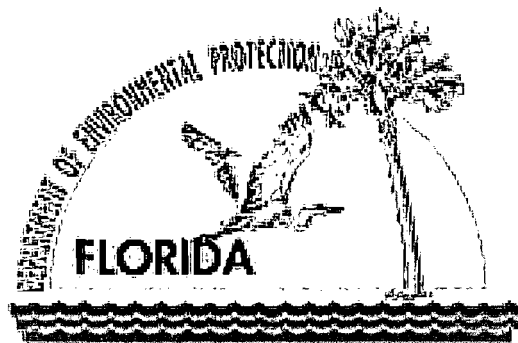
**TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION**

Florida Power and Light Company
FPL Turkey Point Fossil Plant

1,150-Megawatt Combined Cycle Power Project

Miami-Dade County

DEP File No. 025003-006-AC (PSD-FL-338)



Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section

May 28, 2004

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company
9700 Southwest 334th Street
Homestead, Florida 33035
Authorized Representative:
H.O. Nunez, Plant General Manager

Processing Schedule

- Received Site Certification and PSD application on November 14, 2003;
- Additional information requested via Power Plant Siting Office on January 20, 2004;
- Received additional information on March 1, 2004;
- Siting Application Found Sufficient on April 7, 2004;
- Intent to Issue PSD Permit distributed May 28, 2004.

Facility Description and Location

The Florida Power and Light (FPL) Company operates the Turkey Point Fossil Plant, which is located south of Miami, east of Homestead and Florida City and adjacent to Biscayne Bay, in Miami-Dade County. The existing Turkey Point Fossil Plant consists of two fossil fuel-fired steam electrical generating units and five "Black Start" diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The location of the Turkey Point Fossil Plant is shown in Figures 1 and 2.



Figure 1. Location of Turkey Point



Figure 2. Turkey Point Fossil Plant

The Turkey Point Fossil Plant is located generally east of the Class I Everglades National Park and is approximately 20 kilometers northeast of the nearest boundary to the park. Biscayne National Park encompasses the general area to the east of the plant.

Regulatory Categories

Title III: The facility is a “Major Source” of hazardous air pollutants (HAPs). Based on the available information, the project is potentially subject to at least one National Emission Standard for Hazardous Air Pollutants (NESHAP) and the applicable Maximum Achievable Control Technology (MACT).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or “Major Source” of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAPs. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is a Major Facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is a steam electrical generating plant. The project will result in more than 75 MW of steam-generated electrical power and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a “4-on-1” combined cycle unit (Unit 5) consisting of the following equipment and specifications: four 170 MW gas turbine-electrical generator sets; four gas-fired heat recovery steam generators (550 mmBtu/hour); four exhaust stacks between 130 and 150 feet in height; a common steam-electrical generator (470 MW); a 22-cell mechanical draft cooling tower; a 4.3 million gallon diesel fuel storage tank; and other associated support equipment. Gas turbines are also called combustion turbines.

Gas Turbine/HRSG Units: Each gas turbine/HRSG unit consists of a nominal 170 MW General Electric 7FA gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, and a supplementary gas-fired heat recovery steam generator (HRSG). Following are additional project characteristics.

- **Fuels:** Each gas turbine will fire natural gas as the primary fuel and *ultra low sulfur* (0.0015% Sulfur) distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 500 hours per year per gas turbine (or equivalent) for oil firing.
- **Generating Capacity:** Each of the four gas turbines has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Each of the four heat recovery steam generators (HRSGs) provides steam to the single steam turbine electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the “4-on-1” combined cycle unit is 1150 MW.

- **Controls:** CO, PM/PM₁₀, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO₂ will be minimized by firing natural gas and restricting the amounts of ultra low sulfur distillate oil. NO_x emissions will be reduced with dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_x controls, a selective catalytic reduction (SCR) system further reduces NO_x emissions during combined cycle operation.
- **Continuous Monitors:** Each gas turbine is required to continuously monitor NO_x emissions in accordance with the acid rain provisions. The same monitors as well as CO monitors are employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- **Stack Parameters:** Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is at least 130 feet tall with a nominal diameter of 19 feet. The following summarizes the exhaust characteristics:

<u>Fuel</u>	<u>Heat Input Rate (LHV)</u>	<u>Compressor Inlet Temp.</u>	<u>Exhaust Temp., °F</u>	<u>Flow Rate ACFM</u>
Gas	1608 mmBtu/hour	59° F	202° F	1,023,872
Oil	1830 mmBtu/hour	59° F	295° F	1,224,407

Project Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressors of the GE 7FA combustion turbines proposed for this project. The air is compressed by a pressure ratio of about 15 times atmospheric pressure. A portion of the compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the turbine section at temperatures of approximately 2600 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature greater than 1100 °F and high excess oxygen and is available for additional energy recovery.

All units will ultimately operate in combined cycle mode in which the combustion turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator (HRSG). The steam, in-turn, drives a separate steam turbine-electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

Figure 3 is a simplified diagram of combined cycle operation.

How a Combined Cycle Plant works

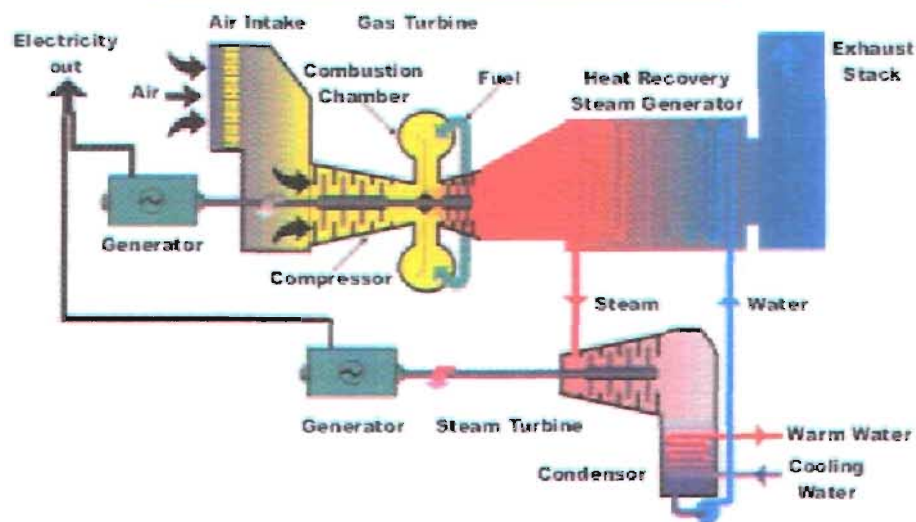


Figure 3. Key Components of a Combined Cycle Unit

The applicant has also requested the following modes of operation within the normal combined cycle operation.

- **Fogging:** Evaporative cooling (also known as “fogging”) is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging will be implemented at ambient temperatures of 60° F or higher.
- **Duct Burning:** Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2880 hours of duct burning per year for each gas unit.
- **High Power Modes (HPM):** These include Power Augmentation (PA) and Peaking (PK). Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine. PK is based on greater fuel use and combustion turbine temperatures resulting in greater power production. PA and PK can cause greater uncontrolled NO_x emissions. PA causes greater uncontrolled CO emissions while PK theoretically causes less CO emissions. The applicant requests 400 hours of HPM for each unit and only when using the Duct Burners.

Further process details are provided in the Draft determination of Best Available Control Technology (BACT) in Section 4.0 below.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, and cooling tower).

Table 1. Applicant's Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	464	100	Yes
Pb	0.026	0.6	No
NO _x	312	40	Yes
PM/PM ₁₀	420/229	15/25	Yes
SO ₂	193	40	Yes
SAM	19	7	Yes
VOC	68	40	Yes

3. RULE APPLICABILITY

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Miami-Dade County Code of Ordinances

Chapter	Description
24 - II	Air Quality
24.41.1	Prohibitions against Air Pollution (Ringleman)
24.41.3	Sulfur Dioxide (Liquid Fuel Sulfur Dioxide Emissions)
24.41.6	Storage and Handling of Petroleum Products (Reid Vapor Pressure)

Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project are required for NO_x, CO, VOC, SO₂, SAM and PM/PM₁₀.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" - An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which

the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

- a. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*
- b. Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

- 3. A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

- 1. Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).*
- 2. All scientific, engineering, and technical material and other information available to the Department.*
- 3. The emission limiting standards or BACT determinations of any other state.*
- 4. The social and economic impact of the application of such technology.*

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.

4.2 NO_x BACT Determination

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_x forms in the high temperature area of the gas turbine combustor. Thermal NO_x increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_x formation. Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_x is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_x control by lean combustion.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_x formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_x formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles.

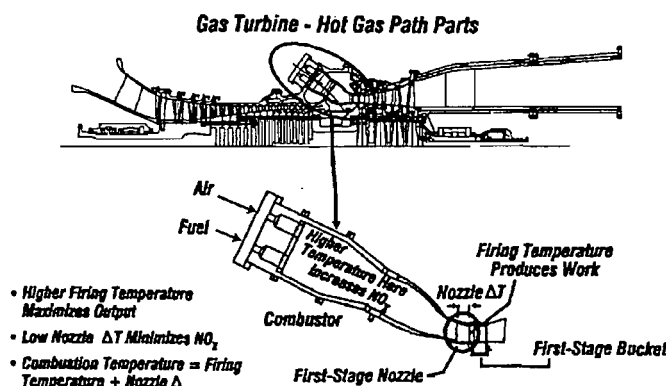


Figure 4 – Relation between Flame Temperature and Firing Temperature

Fuel NO_x is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as this FPL project.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O₂). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O₂ for each turbine of the FPL project. The proposed NO_x controls will reduce these emissions significantly. For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_x emissions from large utility gas turbines such as the GE7FA is approximately 105 ppmvd @15%O₂. This constitutes the legal floor (absolute maximum NO_x value) in a “Top/Down” BACT determination.

Descriptions of Available NO_x Controls

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_x emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below.

Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_x (DLN)

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_x formation. Lean premixing of fuel and air prior to combustion can further reduce NO_x emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 5.

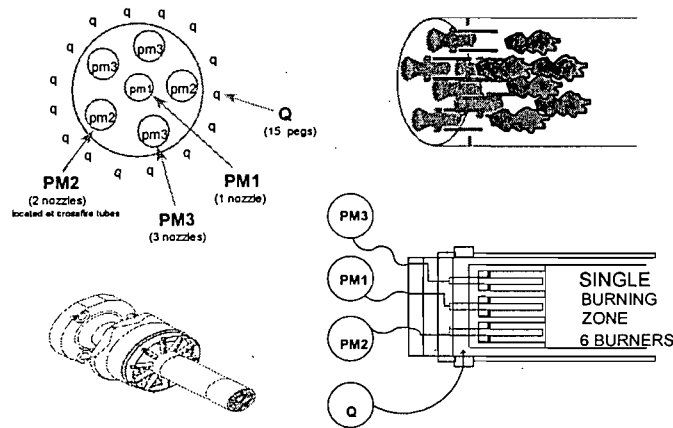


Figure 5 – DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 6 for a unit tuned to meet a 15 ppmvd NO_x limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_x . Actual emissions of CO and VOC are actually much less than suggested by the diagram. However the diagram also suggests the need to minimize operation at low load conditions.

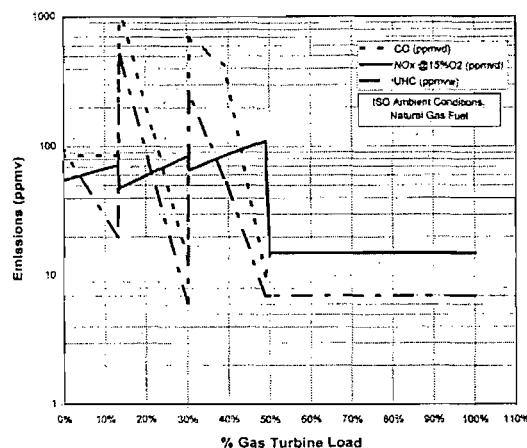


Figure 6 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_x)

The combustor emits NO_x at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the “unburned hydrocarbons” which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.

Table 2. Test Results for GE 7FA Gas Turbine, TECO Polk Power (Simple Cycle)¹

Percent of Full Load	NO _x , ppmvd @15% O ₂	CO, ppmvd	VOC, ppmvd
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1

Following are the results for testing of the GE7FA combined cycle unit at the City of Tallahassee Purdom Plant.

Table 3. Test Results for GE 7FA Gas Turbine, City of Tallahassee’s Purdom Station²

Percent of Full Load	NO _x , ppmvd @15% O ₂	CO, ppmvd
70	7.2	ND
80	6.1	ND
90	6.6	ND
100	8.7	0.85

The test results at the TECO and Tallahassee projects confirm NO_x, CO, and VOC emissions substantially less than typical guarantees as discussed below.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_x by combustion technology. This limitation is seen in Figure 7 from an EPRI report.³ Developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 7.

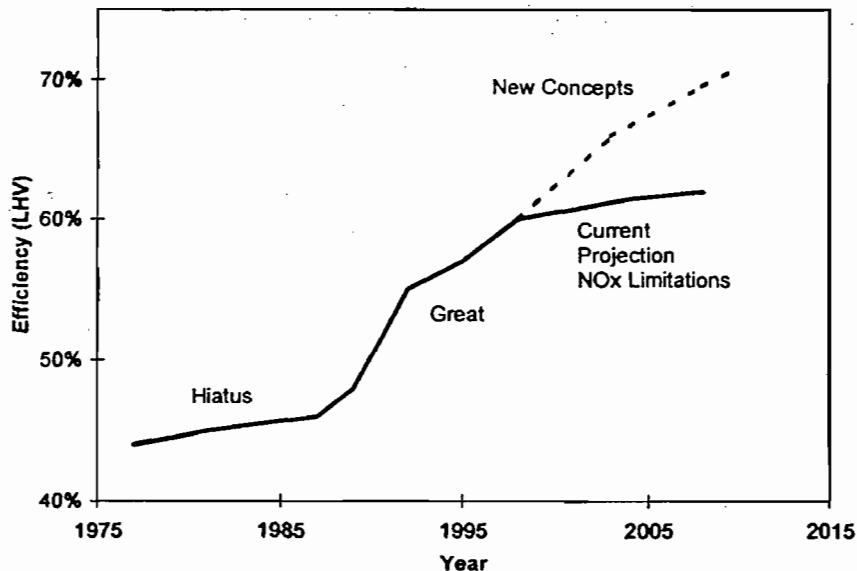


Figure 7 – Efficiency Increases in Combustion Turbines

Further NO_x reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by FPL. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_x emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN technology for NO_x control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95 percent compared with uncontrolled emissions and a reduction greater than 90 percent compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_x emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production).⁴ Low emissions of CO were also achieved. The company is working on versions suitable for the large GE7FA and Siemens Westinghouse products.

DLN is technically possible for fuel oil, but requires a very large and expensive atomization rig and is feasible only where water is virtually unavailable. Therefore, dual fuel combustors employ wet injection to reduce NO_x emissions when firing fuel oil as discussed above.

Catalytic Combustion - XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_x.⁵ In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_x emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system known as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_x production) followed by flameless catalytic combustion to further attenuate NO_x formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.⁶ The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.⁷ By now, five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_x emissions slightly greater than 1 ppm.⁸ Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the FPL Turkey Point project.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an add-on NO_x control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_x emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_x in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts

used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Kissimmee Utilities Authority (KUA) installed an SCR system at the Cane Island Unit 3 project. The KUA project complies with a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued to Competitive Power Ventures (CPV), Calpine, Progress Energy, and Tampa Electric to achieve 3.5 ppmvd. More recently, permits were issued to El Paso Merchant Energy Company for facilities in Broward, Manatee and Palm Beach counties and to CPV for its Pierce facility with a limit each of 2.5 ppmvd @15% O₂ by SCR. Similarly permits were issued in 2003 to FPL for projects in Manatee and Martin County each with a limit of 2.5 ppmvd @15%O₂ by SCR.

Figure 8 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 9 is a photograph of the Progress Energy Hines Power Block I. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

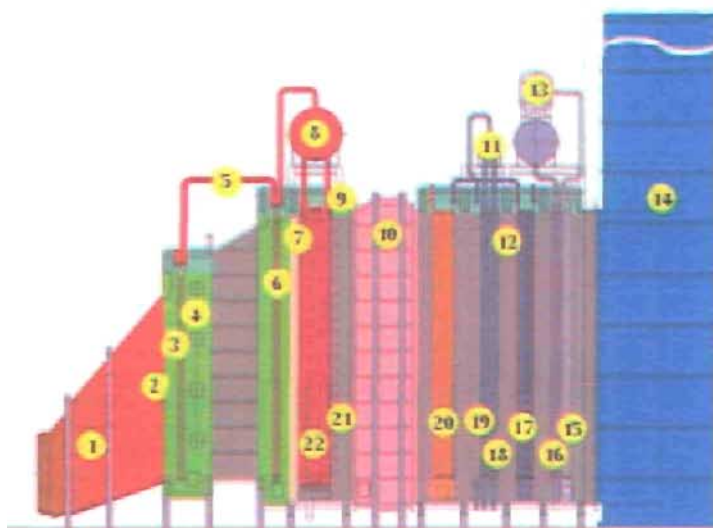


Figure 8 – Key HRSG Components (10 is SCR)

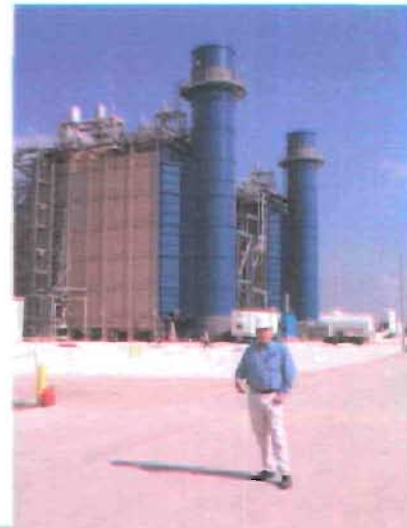


Figure 9 – PGN Hines Block I

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Obviously this is not a problem with natural gas or ultra low sulfur distillate fuel oil. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Following are test results from one project that is cited by EPA Region 9 to show that NO_x emissions less than 2.0 ppmvd @15% O₂ (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR.⁹ The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 4. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA¹⁰

% Full Load	NO _x , ppmvd @15% O ₂	CO, ppmvd	VOC, ppmvd	NH ₃ ppmvd
50	1.4 – 1.7	0.5 – 0.8	0.2 – 0.4	0.08 – 0.2
75	1.5 – 1.6	< 0.1	0.2 - 0.4	0.02 – 0.06
87	1.4 – 1.7	~ 0 – 0.3	0.1	0.05 – 0.1

It is noteworthy as well that the low NO_x emissions were achieved with minimal ammonia (NH₃) emissions. It would be reasonable to expect the ammonia emissions to increase over time to the guaranteed value of 2.0 ppmvd. The project employed Englehard oxidation catalyst for CO and VOC control. In the previous examples, it is noted that the GE 7FA achieved similarly low values throughout the same load range without oxidation catalyst.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_x emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_x reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order 95 to 99%.

SCONO_xTM

This technology is an NO_x and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_x emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

SCONO_xTM systems were installed at seven sites ranging in capacity from 5 to 43 MW.¹¹ Alstom Power was not successful in marketing the product at large facilities.

SCONO_xTM technology (at 2.0 ppmvd) was been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONO_xTM has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONO_xTM systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO_xTM can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from natural gas reforming unit.

Table 5 contains averaged cost values for SCONOXTM and SCR developed by the California Air Resources Board for their Legislature.¹² The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 5. Cost Comparison between SCR and SCONOX for a 500-MW Unit

Capital Cost (\$)		Annual O&M Cost (\$)	
SCR/CO	SCONOX TM	SCR/CO	SCONOX TM
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with SCONOXTM multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the SCONOXTM system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Estimates provided by FPL for the proposed 1,150 MW project claim even greater cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that SCONOXTM is not cost-effective for the present project.

Applicant's NO_x BACT Proposal

The applicant originally proposed a BACT NO_x limit of 2.5 ppmvd @15% O₂. FPL proposed to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. FPL proposed a BACT NO_x emission limit of 10 ppmvd @15% O₂ while burning backup ultra low sulfur fuel oil by a combination of wet injection and SCR.

Since that time, FPL agreed to lower limits as follows:

- a. Gas Firing: 2.0 ppmvd @ 15% O₂, 24-hour average
- b. Oil Firing: 8.0 ppmvd @ 15% O₂, 24-hour average

Department's Draft NO_x BACT Determinations

Table 6 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O₂ on a 1-hour average.

The Department agrees that FPL's proposal of 2.0 ppmvd @15% O₂ on a 24-hour basis and minimization of fuel oil use represents BACT for this project. The limits of 2.0 and 8.0 ppmvd @15% O₂ represent reductions of 98% and 92% for the gas and oil cases respectively when compared with the applicable New Source Performance Standard at 40 CFR 60, Subpart GG.

Table 6. Recent NO_x Standards for “F-Class” Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_x Limit ppmvd @ 15% O₂ and Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2x170 MW GE 7FA
Sithe Mystic, MA	775	2.0 – NG (1-hr)	2x250 MW WH 501G & DBs
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3x175 MW GE 7FA & DBs
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4x180 MW GE 7FA & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2x180 MW ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 – NG(3-hr)	4x160 MW GE 7FA & DBs
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 - FO	4x170 MW GE 7FA & DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2x180 MW ABB GT-24
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2x182 MW WH 501F
Cogen Tech, NJ	181	2.5 (1-hr)	181 MW GE 7FA
FPL Manatee, FL	1,150	2.5 – NG (24-hr)	4x170 MW GE 7FA & DBs
FPL Martin, FL	1,150	2.5 – NG (24-hr) 12 - FO	4x170 MW GE 7FA & DBs
PGN Hines III, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW WH501F
El Paso Manatee, FL	250	2.5 – NG (24-hr)	175 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs
Enron/Ft. Pierce, FL	~250	3.5 – NG (3-hr) 10 - FO	170 MW MHI 501F

Notes:
FO = Fuel Oil

NG = Natural Gas
GE = General Electric

DB = Duct Burner
WH = Westinghouse

PA = Power Augmentation
ABB = Asea Brown Bovari

4.3 CO and VOC BACT Determination

CO and VOC Formation and Control Options

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are typically reported for very large combustion turbines (at least at full load operation) without use of oxidation catalyst.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Based on testing discussed in the NO_x technology section above, GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Similarly, VOC emissions less than 1 ppm have consistently been measured at new GE7FA units throughout the state. Again the results are roughly equal to those at ANP Blackstone.

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE7FA. Performance guarantees are only now “catching up” with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.¹³ The following statement was taken from the report:

“GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation - thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas.”

The following figure from GE’s article is consistent with the data collected by the Department and supports the Department’s analysis of this technical issue.

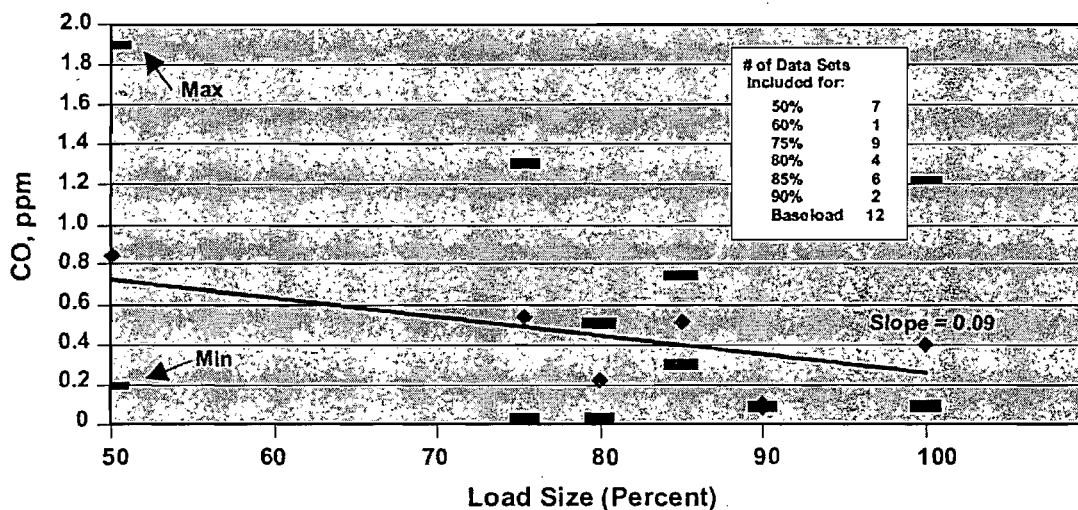


Figure 10. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Duct Burner, HPM, Low Load and Fuel Oil Considerations

The presence of a duct burner (refer to Figure 8, Component 4) and possibility of other high power modes (HPM) including power augmentation (PA) and peaking (PK) complicate the evaluation somewhat.

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (1,100 to 1,200 °F) and high excess air (> 12% O₂). In the design shown in Figure 8, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6).

Figures 11 and 12 are of an individual burner and an array comprising a duct burner. The hot TEG serves as combustion air for gas introduced into the burner array.

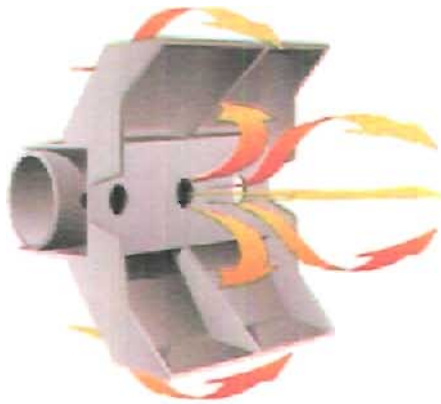


Figure 11 – Individual Burner (Coen)

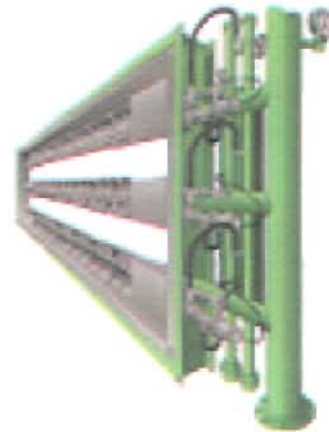


Figure 12 – Burner Array (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG.

Certain configurations (NovelEdge™) are marketed to take advantage of these possibilities and to make it unnecessary to install oxidation catalyst for VOC and CO control because of destruction by the duct burner.¹⁴ Basically, the claim is that a “3 on 1” configuration (3 CT’s & 1 HRSG) producing 750 MW can be replaced with a “2 on 1” configuration by adding very large Coen “Power Plus” DBs in a Nooter Eriksen HRSG and still produce 750 MW. Basically the capital investments are much lower, overall efficiency is higher and the DBs destroy VOC and CO to the point that oxidation catalyst can be avoided.

Following is a table with the results of CO and VOC testing recently completed at the Gulf Power Lansing Smith Plant.¹⁵ The units tested were GE7FA combustion turbines (CT) of the same type that FP&L will install at the Manatee Power Plant. Tests were conducted on each combustion turbine while using duct burners (DB).

Table 7. CO and VOC Emissions - Gulf Power Plant Smith GE 7FA Units (ppmvd@15% O₂)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CT & DB)	1.21	0.15
Gulf Smith Unit 5 (CT & DB)	1.26	0.31
Gulf Smith Unit 4 (CT & PA)	5.18	0.61
Gulf Smith Unit 5 (CT & PA)	8.61	0.38

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

As seen from Table 7, emissions of CO and VOC are very low when the DBs are used and without PA. The values under the DB mode are roughly the same as those for the normal operation mode (no DB or PA) in Tables 2 and 3 above.

The Gulf Smith units also provide an example of power augmentation (PA) with the duct burners (DB) off. Emissions when employing PA are clearly greater than the base case in Tables 2 and 3 and greater than the DB case.

Following is a table with results of CO and VOC emissions from GE 7FA units at Alabama Power's Plant Barry when operating simultaneously in DB and PA modes.¹⁶

Table 8. CO and VOC Emissions - Alabama Power Plant Barry GE 7FA Units (lb/mmBtu)

Unit (Modes)	CO	VOC
Barry Unit 7A (CT & DB & PA)	0.018 (< 9 ppmvd@15% O ₂)	0.000 (< 1 ppmvd@15% O ₂)
Barry Unit 7B (CT & DB & PA)	0.008 (< 4 ppmvd@15% O ₂)	0.000 (< 1 ppmvd@15% O ₂)

Comparison of the results from the Gulf Power and Alabama Power units suggests that the PA mode increases CO emissions whether or not the duct burners are used, while VOC emissions remain low.

Recently, the Department received additional information regarding tests conducted at the recently commissioned Southern/KUA/OUC/FMPA project located at the OUC Stanton Facility. The two units are equipped with ducts burners and practice power augmentation. Following are the results of those tests.¹⁷

Table 9. Emissions from Stanton A Combined Cycle GE 7FA Units (ppmvd@15% O₂)

Unit (Modes)	NO _x	CO	VOC	NH ₃
Unit 25 (CT)	2.5	0.5	0.04	0.2
Unit 25 (CT & DB)	2.5	1.6	0.2	0.4
Unit 25 (CT & PA)	3.1	8.3	1.7	0.9
Unit 26 (CT)	3.1	0.5	0.49	0.1
Unit 26 (CT & DB)	3.2	1.6	0.26	0.5
Unit 26 (CT & PA)	2.7	6.7	0.8	0.9

The results from Stanton A add further credence to the hypotheses that CO and VOC emissions are low when using duct burners and are greatest when practicing power augmentation.

According to information from General Electric, CO emissions during PK will actually be less than during normal operation while NO_x emissions will increase. This is because of higher flame temperature in the combustors during PK compared with normal operation.¹⁸ The projections regarding NO_x were confirmed recently at an FPL facility.¹⁹ Baseline NO_x emissions (DLN control only) increased from 7 to 9.6 ppmvd @ 15% O₂, while power production from the CT-electrical generator increased by 3 or 4 MW. No tests were reviewed by DEP to confirm the CO emissions reduction effect of PK.

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in the Table below. No appreciable differences are noted for large combustion turbines when they are operated on fuel oil versus natural gas. This conclusion is noteworthy because wet injection for basic NO_x control is practiced on all such units when firing fuel oil.

Table 10. CO, VOC Test Results. GE 7FA Gas Turbines firing Fuel Oil. (ppmvd @15% O₂)

<u>Facility/Unit (load %)</u>	<u>CO</u>	<u>VOC</u>
Martin Unit 8A (100%) ²⁰	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
Purdom Unit 8 (~50%) ²¹	1.2	
Purdom Unit 8 (100%)	1.3	
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%) ²²	2.1	1.1
Stanton A – Unit 25 (100%)	1.0	1.1
Stanton A – Unit 26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%) ²³	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

The Department did not compare the manner in which water or steam is introduced into the CT during wet injection versus power (steam) augmentation to explain why the CO results from the two modes are different. The Department concludes that the low CO and VOC emissions while burning fuel oil constitute an empirical observation just as the high CO emissions during the PA mode also constitute an empirical observation.

One final observation is that CO and VOC emissions were low during a recent test of a GE 7FA combined cycle unit while firing fuel oil and using a gas-fired duct burner. The results are given in the following table.

Table 11. Emissions from GE 7FA CT - Fuel Oil & Gas-Fired Duct Burner (ppmvd @15% O₂)

<u>KUA 3/Mode²⁴</u>	<u>NO_x</u>	<u>CO</u>	<u>VOC</u>	<u>NH₃</u>
CT & DB & FO	15	1.4	0.1	1.5

FP&L does not propose fuel oil firing while using gas-fired duct burners, but the results are instructive because even this unusual case yields low CO, VOC, and even NH₃ emissions.

The Department provided the information from the research summarized above to GE and FP&L. As a result, FP&L was able to obtain a guarantee for the FO case of 8 ppmvd @15% O₂.

El Paso was required to install oxidation catalyst at permitted but deferred (or cancelled) combined cycle projects using GE7FA CTs in Broward, Palm Beach, and Manatee Counties. The purpose of the catalyst for those projects is to limit CO emissions during continuous PA as opposed to the infrequent power augmentation (< 400 for sum of PA and PK) planned by FPL for the Turkey Point Unit 5 project.

Another consideration is "low load" operation. Several operators in Florida installed, will install, or are considering installing oxidation catalyst because: the supplier could not guarantee low CO emissions at medium loads (50 to 70 percent); the units actually exhibited high emissions at such loads; or the units required very long warm-up periods under low load (< 50% and very high CO) conditions.

These include Lakeland McIntosh Unit 3, Seminole Payne Creek, Enron Fort Pierce (deferred), and Progress Energy Hines Power Block II. This is in contrast to the GE 7FA units that exhibit low CO emissions at 50 percent.

Determinations CO, VOC, and PM/PM₁₀ Emission Limit Determination

The following table is a list of recent CO and VOC (and PM) determinations for project throughout the country. FPL's proposal is included for comparison.

Table 12. CO, VOC, and PM Standards for "F-Class" Combined Cycle Units

Project Location	CO - ppmvd (@15% O₂)	VOC - ppmv (@15% O₂)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	1.0	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	1.0 (DB off) 1.7 (DB on))	0.008 (NH ₃ = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	1.0 (DB off) 2.0 (DB on))	0.01
Duke Morro, CA	2.0 (Ox-Cat)	1.15 (DB off) 2.0 (DB on)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	1.4	0.002 (NH ₃ = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	1.0 (DB off) 1.64 (DB on))	0.0048 (NH ₃ = 5 ppmvd) 0.0005 Cool Tower Drift
FPL Turkey Pt., FL (applicant proposal)	4.1 – NG (DB off) 7.6 – NG (DB on) 14.1 – NG (DB+PA) 8.0 – FO	1.3 – NG (DB off) 1.9 – NG (DB on) 2.2 – NG (DB+PA) 2.8 – (FO)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	3 – 7.5 lb/hr	0.011
Calpine OEC, PA	10 (1-hr)	1.8	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	1.2	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH ₃ = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH ₃ = 5
PGN Hines III, FL	10 - NG (3.5 if Ox-Cat) 20 – FO (7 if Ox-Cat)	2 – NG 10 – FO	10% Opacity NH ₃ = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	1.1 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/mmBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity

Notes:
FO = Fuel Oil

NG = Natural Gas
GE = General Electric

DB = Duct Burner
WH = Westinghouse

PA = Power Augmentation
ABB = Asea Brown Bovari

Applicant's CO and VOC BACT Proposal

In response to comments by EPA and data provided by the Department, FPL obtained CO emission guarantees of 4.1 and 8.0 ppmvd @15% O₂ when firing natural gas and fuel oil respectively. These values represent the lowest guarantees yet without the need for oxidation catalyst. The applicant's revised BACT proposal is as follows:

Table 13. FPL Proposed BACT Emissions Limits for CO and VOC (@ 59 °F)

<u>Modes</u>	<u>Hours</u> (Max)	<u>CO</u> (ppmvd @15% O ₂)	<u>VOC</u> (ppmvd @15% O ₂)
Gas Firing	8,760	4.1	1.3
Gas & DB	2,880	7.6	1.9
Gas & DB & HPM (PA/PK)	400	14.1/11	2.2
Fuel Oil Firing	500	8.0	2.8

Department's CO and VOC BACT Proposal

Based on the data available to the Department, FP&L's respective proposed CO emission limits for normal operation and fuel oil firing of 4.1 and 8.0 ppmvd @ 15% O₂ are acceptable. A detailed cost assessment would reveal that the cost to achieve lower CO emissions by installation of oxidation catalyst is not warranted. This cost has been estimated by General Electric at approximately \$8,000 per ton. While the Department does not necessarily accept the GE estimate, oxidation catalyst would not be cost-effective.

There will be considerable use of duct burners (DB). Although the Department believes CO emissions under DB in terms of ppmvd @15% O₂ will be approximately equal to emissions under the normal mode, the requested value of 7.6 ppmvd @15% O₂ is acceptable. This provides for a margin of uncertainty because the manufacturer of the DB assumes that the burner does create some CO and adds to that generated in the CT. Requirement of oxidation catalyst could reduce that uncertainty, but would not be cost effective given the tonnage removed for the cost and the empirical observation that emissions will actually be low (~ 2 ppmvd @15% O₂).

The High Power Modes (HPM) of Power augmentation (PA) and peaking (PK) are low probability scenarios that will occur for only 400 hours per CT and only in conjunction with use of the duct burners. The requested values of 11 and 14.1 ppmvd @ 15% O₂ are acceptable for PK and PA respectively in conjunction with DB.

The Department will set a continuous 24-hr CO limit of 8.0 ppmvd to be comprised of all firing modes and durations with the exception of simultaneous DB & PA, which will be subject to a separate limit of 14.1 ppmvd @15% O₂. Stack testing will still be required to demonstrate compliance with the guaranteed values for the key normal, fuel oil and duct burner modes.

Similarly, the Department accepts FP&L's proposals for VOC emission limits. It is noted that total VOC emissions will be only 68 TPY combined from the four combustion turbines. The test data reviewed by the Department indicate that actual emissions are likely to be less than the PSD significant emission rate of 40 TPY. The BACT values provide a small margin of safety that assures compliance.

4.4 Sulfur Dioxide (SO₂) and Sulfuric Acid Mist (SAM) BACT Determination

SO₂ control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO₂.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed as BACT the use of ultra low sulfur fuel oil (0.0015 percent sulfur) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas (≤ 2 gr/100 SCF). This will be the first project in the state required to use the cleanest fuel oil scheduled to be available by the time the new unit begins operation. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8% by weight.

The applicant estimated total emissions for the project at 193 tons per year of SO₂ and 19 tons per year of sulfuric acid mist. The Department accepts FP&L's BACT proposal for SO₂ and SAM.

4.5 Particulate Matter (PM/PM₁₀) BACT Determination and Ammonia (NH₃) Control

PM/PM₁₀ Formation and Control Options

PM and PM₁₀ are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ultra low sulfur distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The ultra low sulfur fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 500 hours per year making any conceivable add-on control technique for PM/PM₁₀ either unnecessary or impractical.

The following table is a summary of PM₁₀ emissions provided by General Electric to FP&L from GE 7FA units operating on natural gas or fuel oil.^{25, 26}

Table 14. PM₁₀ Emissions from GE 7FA Units (pounds per hour)

<u>Fuel</u>	<u>Range</u>	<u>Average</u>	<u>Std. Deviation</u>
Natural Gas - Front-half (filterable)	0 - 17	4.8	
Natural Gas - Back-half (condensable)	0 - 15	14	
Natural Gas Total	1 - 29	7.5	
Fuel Oil - Front-half (filterable)	1 - 20	10	4
Fuel Oil Back-half (condensable)	3 - 21	14	6
Fuel Oil Total	4 - 37	24	9

Recent PM/PM₁₀ emission limits are included in Table 12. Comparison is not simple because some of the limits represent filterable particulate matter while some of the limits represent the sum of filterable and condensable matter.

As previously discussed, there will be emissions of NO_x, SO₂ and SAM. These pollutants are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. The NO_x control technology of SCR can increase PM/PM₁₀ emissions from the stack due to formation of ammonium sulfates prior to exiting.

Formation of ammonium species emitted from the stacks can be minimized by limiting the emissions of ammonia (known as slip). Elevated levels of ammonia slip may indicate a degrading catalyst. Almost all jurisdictions include a slip limit in conjunction with NO_x control technologies that rely on ammonia injection. A few permit limits are given in Table 12. Very low values (≤ 0.2 ppmvd) were achieved at the ANP Blackstone project as described in Table 4.

It is noted that NH₃ emissions from the Stanton projected cited in Table 9 above ranged from 0.1 to 0.9 ppmvd @15% O₂ while firing natural gas. NH₃ and NO_x emissions while burning fuel oil were approximately 3 and 8 ppmvd respectively. Results from tests at KUA Unit 3 indicate that NH₃ emissions were 1.5 ppmvd @15% O₂ when firing fuel oil. The Department proposes an ammonia limit of 5 ppmvd @15% O₂.

Cooling Tower PM Emissions

The applicant's preliminary design includes a 22-cell mechanical draft cooling tower with the following specifications: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators with a drift rate of no more than 0.001 percent.

Cooling towers may emit particulate matter based on the loading in the recirculating water.

FPL estimates annual emissions of 201 tons of PM due to drift losses assuming total dissolved solids (TDS) of 30,000 mg/L. PM₁₀ emissions were projected to be 10 TPY based on TDS of 4,000 mg/L.

For reference, PM emissions estimated from the Martin Unit 8 project were estimated to be substantially less than from the Turkey Point project because the cooling water contains less TDS. It is possible for FPL to reduce the drift rate to further minimize PM emissions. For

example, FPL Energy agreed to a drift rate limit of 0.0005% in conjunction with a TDS limit of 6,000 mg/L for the Tesla Project in Alameda County California.

The Department determines the draft BACT to be a design drift rate of no more than 0.0005% of the circulating water flow rate. At this level, maximum potential PM emissions from the cooling tower are expected to be on the order of 100 tons per year.

Applicant's PM/PM₁₀ Proposal

FP&L proposes PM/PM₁₀ BACT equal to 14.9 pounds per hour (lb/hr, front-half) when firing natural gas under all loads and modes of operation (DB, PK, PA). They propose a limit of 17.6 lb/hr (front-half) when firing fuel oil. They also propose an opacity limit of 10%. FPL proposes PM control from the cooling tower to be accomplished by a 0.001% drift rate design limitation.

Department's Draft PM/PM₁₀ BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbines may fire distillate oil as a restricted alternate fuel (≤ 500 hours per year), which shall contain no more than 0.0015% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- Ammonia emissions (slip) shall not exceed 5 ppmvd.
- The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

4.6 Summary of Department Draft BACT Determination

Emissions from each gas turbine shall not exceed the values given in the following table.

Table 15. Draft BACT Determination – FPL Turkey Pt. Unit 5

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- Continuous compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.
- Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂.
- The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
- The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
- Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

5 NEW SOURCE PERFORMANCE STANDARDS

5.1 Combustion Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_x (gas) ≤ 110 ppmvd @ 15% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NO_x (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

5.2 Duct Burners

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 495 MMBtu per hour (LHV). This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- $\text{NO}_x \leq 1.6$ lb/MW-hr (gross)
- $\text{SO}_2 \leq 0.20$ lb/MMBtu
- $\text{PM} \leq 0.03$ lb/MMBtu

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.06 lb/MW-hr for NO_x . The specifications for the ultra low sulfur fuel oil and natural gas insure that the NSPS PM and SO_2 emission limits for the duct burners will easily be met. For example, if emissions from a duct burner alone exceeded its NSPS standards, then emissions from the duct burner and associated combustion turbine combined would exceed the BACT limits. An Appendix to the permit will summarize applicable federal requirements.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NSHAP Subpart YYYYY, which became final on March 5, 2004.²⁷ According to the final rule, each unit would be considered a “new lean premix gas-fired stationary combustion turbine”. Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.²⁸ EPA has stayed the applicability of YYYY to units such as those proposed for the Turkey Point project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

Based on the same GE technical cited in the Section 4.3 above, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposes to meet the limit proposed in YYYY of 91 ppmvd.

The very low VOC and CO emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_x technology employed by these units insure that formaldehyde emissions will be at the lowest end of the spectrum.

The draft permit will reflect the present status of the rule. The final permit will reflect Subpart YYYY to the extent that it is applicable on the date the Department issues its final decision on the present application.

7. PERIODS OF EXCESS EMISSIONS

7.1 Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_x emissions.

7.2 Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.
- For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.
- Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup, up to three hours of excess emissions are allowed. “Warm startup” is defined as a startup following a shutdown lasting at least 24 hours.
- For cold startup to combined cycle operation, up to four hours of excess emissions are allowed. “Cold startup” is defined as a startup following a shutdown lasting at least 48 hours.
- For shutdown, up to three hours of excess emissions are allowed.
- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer’s specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

While NO_x emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

Combined Cycle Operation with Dump Condenser: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

8. DEPARTMENT’S ESTIMATED ANNUAL EMISSIONS

The following table shows the Department’s estimated annual emissions from the completed combined cycle unit, including the cooling tower based on the draft permit conditions.

Pollutant	CO	Pb	NO _x	PM	PM ₁₀	SO ₂	SAM	VOC
Emissions (TPY)	464	0.026	312	320	224	193	19	68

The following ambient impact analyses were conducted using the higher values for PM and CO based on the applicant’s original proposed BACT or subsequent revisions.

9. AIR QUALITY IMPACT ANALYSIS

9.1 Introduction

The proposed project will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM₁₀, CO, NO_x, SO₂, VOC and SAM. PM₁₀, SO₂ and NO_x are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM and VOC. However, VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

9.2 Major Stationary Sources in Miami-Dade County

The current largest stationary sources of air pollution in Miami-Dade County are listed below. The information is from annual operating reports submitted to the Department except as noted.

Table 16. Major Sources of SO₂ in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Florida Power & Light	Turkey Pt. Plant (existing boilers)	9,135 (EPA)
Titan Industries	Tarmac Pennsucco Cement	~ 1,000 (est.)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	231
<i>Florida Power & Light</i>	<i>Turkey Pt. Plant (proposed project)</i>	<i>193</i>
Waste Management	Medley Landfill and Recycling	129
Miami-Dade County WASD	MDWASD/Central District WWTP	88

Table 17. Major Sources of NO_x in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Florida Power & Light	Turkey Pt. Plant (existing boilers)	6,263 (EPA)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	5,010
Titan Industries	Tarmac Pennsucco Cement	2,469
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	1,316
Homestead City Utilities	G.W. Ivey Power Plant	655
Florida Power & Light	Cutler Power Plant	547
<i>Florida Power & Light</i>	<i>Turkey Pt. Plant (proposed project)</i>	<i>312</i>

Table 18. Major Sources of CO in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	3,106
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	995
Florida Power & Light	Turkey Pt. Power Plant (existing)	865
<i>Florida Power & Light</i>	<i>Turkey Point Plant (proposed project)</i>	<i>464</i>

Table 19. Major Sources of PM in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Florida Power & Light	Turkey Point Power Plant (existing)	734
<i>Florida Power & Light</i>	<i>Turkey Point Plant (proposed project)</i>	<i>419</i>
Titan Industries	Tarmac Pennsucco Cement	~ 325 (est.)
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	157

Table 20. Major Sources of VOC in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Nailite International	Nailite International	147
Fine Art Lamps	Fine Art Lamps	88
Waste Management	Medley Landfill and Recycling	80
Contender Boats Inc.	Contender Boats Site #1	78
DM Industries, Ltd.	DM Industries	76
GP Plastics Corp.	GP Plastics Corp. Miami Plant	76
<i>Florida Power & Light</i>	<i>Turkey Point Plant (proposed project)</i>	<i>68</i>
Florida Power & Light	Turkey Point Power Plant (existing)	64
Avanti Press, Inc.	Avanti Press, Inc.	64

Emissions from the proposed project are relatively low considering the high capacity (1,150 megawatts). For example the existing units emit 20 to 50 times as much SO₂ and NO_x despite their smaller capacity (total 880 MW).

For reference, an ongoing modernization project at Titan Industries, Tarmac Pennsucco Cement Plant will greatly reduce SO₂ emissions. A similar project at the CSR Rinker Miami Cement Plant already reduced SO₂ emissions by approximately 2,000 tons per year.

9.3 Pollutant Emissions in Miami-Dade County

Emission inventories have been prepared for each county in Florida for evaluation of regional haze. The following table is a listing of pollutant estimates from all kinds of sources in Miami-Dade County during 2002.²⁹ These include stationary sources, area sources, and on-road and non-road mobile sources. The category of area sources also includes fires.

Emissions from the proposed Turkey Point Unit 5 project are included. Emissions of ozone precursors (NO_x and VOC) from the proposed project will be minimal compared to total existing pollutant load. Thus the contribution to regional ozone formation will be very low.

Table 21. Pollutant Emissions in Miami-Dade County by Source Category (2002)

Source Category	SO ₂	NO _x	CO	PM ₁₀	VOC	NH ₃
Stationary Sources	10,262	12,929	3,891	2,516	1,757	0
Area Sources	13,266	4,580	78,670	35,438	53,167	2,925
On-Road Mobile	1,989	46,158	492,121	1,230	49,007	1,940
Non-Road Mobile	1,976	19,062	197,091	24,946	15,646	11
Total	27,492	82,729	771,773	64,131	119,578	4,876
<i>Turkey Pt. Unit 5</i>	193	320	450	229	68	~200

The contributions to regional particulate matter emissions will also be very low even if all SO₂, NO_x, and NH₃ are ultimately converted to PM.

9.4 Air Quality and Monitoring in the Miami-Dade County

The Miami-Dade County Department of Environmental Resource Management (DERM) operates fifteen monitors at eleven sites measuring PM₁₀, PM_{2.5}, ozone, CO, SO₂ and NO₂. The 2002 monitoring network is shown in the figure below.



Figure 13. Miami-Dade DERM Ambient Air Monitoring Network

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Measured ambient air quality information is summarized in the following table.

Table 22. Ambient Air Quality in Miami-Dade County Nearest to Project Site (2002)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM ₁₀	Homestead	24-hour	38	31		150 ^a	ug/m ³
		Annual			19	50 ^b	ug/m ³
SO ₂	US 27, SR 821	3-hour	5	5		500 ^a	ppb
		24-hour	4	4		100 ^a	ppb
		Annual			2	20 ^b	ppb
NO ₂	Rosenstiel, V. Key	Annual			6	53 ^b	ppb
CO	S. Dixie Highway	1-hour	3	3		35 ^a	ppm
		8-hour	2	2		9 ^a	ppm
Ozone	Perdue Medical	1-hour	0.091	0.086		0.12 ^c	ppm
		8-hour	0.070	0.064		0.08 ^c	ppm

a - Not to be exceeded more than once per year

b - Arithmetic mean

c - Not to be exceeded on more than an average of one day per year over a three-year period

The data are reasonably representative of air quality near Turkey Point with the exception of SO₂. Since the existing Turkey Point fossil units constitute the largest source of SO₂, it is doubtful that the Station on US 27 and SR 821 adequately represents the Homestead area. However, measurements at sites throughout the state that are in the vicinity of larger SO₂ sources than the existing Turkey Point units are also in attainment with the respect to the SO₂ NAAQS. Therefore it is reasonable to conclude that SO₂ concentrations off of the Turkey Point site are also in attainment of the SO₂ NAAQS.

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels. The exception is ozone because it is formed from precursors that are clearly available (NO_x and VOC). The precursors are more available during drought years. The tendency to form ozone is accentuated by hot ambient temperature, high pressure, and relatively low wind speed.

9.5 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM₁₀, CO, NO_x and SO₂. A significant impact analysis is performed on each of these pollutants to determine if a project can even cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class I Everglades National Park (ENP) and the PSD Class II Areas (everywhere except the ENP).

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all facilities or projects (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM₁₀, CO, NO_x, and SO₂ air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except ENP). These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 23. Maximum Projected Air Quality Impacts from FP&L Turkey Point Unit 5 for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m ³)	Significant Impact Level (ug/m ³)	Baseline Concentrations (ug/m ³)	Ambient Air Standards (ug/m ³)	Significant Impact?
SO ₂	Annual	0.1	1	~5	60	NO
	24-Hour	2	5	~10	260	NO
	3-Hour	8	25	~13	1300	NO
PM ₁₀	Annual	0.2	1	~20	50	NO
	24-Hour	3.7	5	~40	150	NO
CO	8-Hour	30	500	~2300	10,000	NO
	1-Hour	73	2000	~3450	40,000	NO
NO ₂	Annual	0.3	1	~11	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Everglades National Park (ENP) located about 21 km to the west of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM₁₀, NO_x and SO₂ air quality impact analyses for this project indicated that maximum predicted impacts from annual SO₂, annual PM₁₀, and NO₂ are less than the applicable SILs for the Class I area. Therefore no further detailed modeling efforts are required for these pollutants.

Maximum predicted impacts from 24-Hour and 3-Hour SO₂, and 24-Hour PM₁₀ are greater than the applicable SILs for the Class I area. Although the values are miniscule compared with the ambient air quality standards given in the previous table, additional modeling was required as discussed below.

Table 24. Maximum Air Quality Impacts from the FP&L Turkey Point Unit 5 Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m ³)	Class I Significant Impact Level (ug/m ³)	Significant Impact?
PM ₁₀	Annual	0.04	0.2	NO
	24-hour	0.5	0.3	YES
NO ₂	Annual	0.073	0.1	NO
SO ₂	Annual	0.04	0.1	NO
	24-hour	0.4	0.2	YES
	3-hour	1.8	1	YES

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

Table 25. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m ³)	De Minimis Level (ug/m ³)	Baseline Concentrations (ug/m ³)	Impact Greater Than De Minimis?
PM ₁₀	24-hour	4	10	~40	NO
NO ₂	Annual	0.3	14	~11	NO
SO ₂	24-hour	2	13	~10	NO
CO	8-hour	30	575	~2300	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant

estimated annual potential VOC emissions from the project to be 68 tons per year. Therefore, preconstruction monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for 24-Hour and 3-Hour SO₂, and 24-Hour PM₁₀ in the ENP Class I area;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Miami International Airport. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in *NRDC v. Thomas*, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP beyond 50 km from the proposed project. Meteorological MM4 and MM5 data used in this model was from 1990, 1992 and 1996. Meteorological surface data used were from Tampa, Daytona Beach, Vero Beach, Fort Myers, Key West, Miami, West Palm Beach and Orlando. Meteorological upper air data used were from Ruskin, Key West and West Palm Beach. Hourly precipitation data were obtained from 23 stations around the central and southern part of the state.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

Within 50 km of the source, the EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. Characteristics, parameters and data used in this model are detailed above.

For Visibility within 50 km, the EPA-approved VISCREEN model was used. VISCREEN calculates the potential impact of a plume of specified emissions for specific transport and dispersion conditions. Surface meteorological data used in this model was obtained from the National Weather Service station in Miami from 1987 to 1991.

Multi-source PSD Class I Increment Analysis

The maximum predicted 3 and 24-hour SO₂ and 24-hour PM₁₀ PSD Class I area impacts from this project and all other increment-consuming sources in the vicinity of the ENP are shown in the following table.

Table 26. PSD Class I Increment Analysis – ENP

Pollutant	Averaging Time	2 nd -Highest-High Unit 5 Max Predicted Impact (µg/m ³)	2 nd Highest-High All Sources Max Predicted Impact (µg/m ³)	Allowable Increment (µg/m ³)	Impact Greater Than Allowable Increment?
SO ₂	24-hour	0.4	4.1	5	NO
SO ₂	3-hour	1.8	17.5	25	NO
PM ₁₀	24-hour	0.5	2.1	5	NO

The existing Turkey Point Units have much greater ground level effects than predicted for the proposed project. This is obvious because emissions from the existing units are approximately 9,000 tons of SO₂ per year, whereas Unit 5 will emit less than 200 tons per year. However these effects are not included because the sources were in operation before the PSD Program and the baseline date for increment consumption.

It is possible to “expand” increment by reducing emissions from existing sources. Examples of SO₂ increment expansion projects are the Rinker Cement Plant modernization that reduced SO₂ emissions by approximately 2,000 tons per year and the on-going Tarmac Cement modernization that will result in a similar reduction.

9.6 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from the natural gas and distillate oil fired gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM₁₀, CO, NO_x, and SO₂ as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS.

Since the project impacts are either less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife will be minimal or insignificant. The following example is instructive.

According to the applicant, lichens are a plant species in the area of the project that are sensitive to air pollutants. SO₂ levels of 200-400 µg/m³ for a 6 hour period in the course of a week for 10 weeks can lead to adverse impacts. SO₂ impacts from the Turkey Point Expansion will be much less than these levels and therefore, will not contribute to adverse impacts on vegetation such as lichens.

Air pollutants can also adversely impact wildlife. According to the application, deer mice numbers will decline when exposed to levels of 13-157 µg SO₂/m³ continuously for 5 months. Annual and 24-hour SO₂ levels predicted from the Turkey Point Expansion will be well below these levels and therefore, will not contribute to adverse impacts on wildlife, such as deer mice.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are slightly greater than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

According to the applicant, the predicted deposition rates of sulfur and nitrogen of 0.014 and 0.024 kg/ha/yr respectively, impacts are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

The low NO_x limit coupled with the use of ultra low sulfur fuel oil and inherently clean natural gas will minimize any possible effects due to sulfur and nitrogen deposition. Additionally the fuels are extremely low in mercury content. The very low sulfur deposition rate from the proposed project will also minimize activation of mercury in the soils by sulfur reducing bacteria.

Impact on Visibility and Regional Haze:

Consultation with the National Park Service Air Quality experts resulted in commitments by the applicant to use ultra low sulfur fuel oil that is not yet available in the Southeast Florida market. Additionally, that consultation also resulted in a commitment to lower NO_x emissions to 2 ppmvd @15% O₂.

The applicant submitted a regional haze analysis for the ENP. The analysis included modeling from the CALPUFF model and VISCREEN model.

Despite the measures proposed, through the application of BACT, to minimize SO₂, NO_x, and PM, the CALPUFF model predicts modeled impacts above the 5% visibility impairment based on criteria from the NPS. If the facility continuously operates on fuel oil, impairment can occur during 2 days in three years under atypical meteorological conditions for coastal Southeast Florida (temperature less than 35 degrees). Because of the limitation in fuel oil use, the probability that these two factors will coincide is low and the most probable expectation is that there will be no days of visibility impairment over a period of three years.

The coherent plume modeling with VISCREEN performed by the NPS showed no adverse impacts on the ENP.

The NPS also did an analysis to determine impacts at Biscayne National Park (a Class II area). The NPS determined that there may be plume impacts when firing oil if winds are from the south. This was determined with a 2.5 ppm NO_x limit for BACT. The 2.0 limit should slightly decrease these impacts. As stated above, fuel-oil firing will be limited to 500 hours per year, thus further reducing the probability of visibility impairment.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. According to the applicant, about 250 additional workers will be needed over the 24-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area.

The project is a response to state-wide electrical growth and the legal requirement that certain investor owned utilities in Florida maintain a 20 percent electrical reserve. This project is one of several projects identified by FP&L in its annual 10 year plans submitted to the Public Service Commission.

Overall the project will not cause additional growth in the given area, but is a response to projected state-wide electrical power demand growth. Although the project could have been located elsewhere in Southeast Florida, the exact location is the result of economic optimization and transmission constraints.

Effects on Gas Supply and on Emissions from other Power Plants in Southeast Florida:

The existing FP&L Turkey Point Fossil Units 1 and 2 are basically residual oil fired units with natural gas co-firing capability. There are similar units at Port Everglades and Riviera Beach. Emissions, particularly of PM, SO₂, and SAM, are much greater for the residual fuel oil portion of the fuel used at the three plants than the natural gas portion.

Because the Turkey Point plant is "at the end of the pipeline," there is some concern regarding the gas supply and the possibility that natural gas usage by Turkey Point Unit 5 can decrease the availability of natural gas by the older units at Turkey Point, Port Everglades, and Riviera Beach.

According to the Annual Operating Reports received by the Department, the three plants used approximately 33 trillion BTUs of natural gas in 2002. The new Turkey Point Unit 5 will consume more than 60 trillion BTUs of natural gas.

For reference, in 1998, the natural gas transmission capacity to the state of Florida was approximately 1 billion standard cubic feet per day (bscfd). There have since been several expansions by Florida Gas Transmission Company. The Gulfstream Pipeline across the Gulf of Mexico was completed in 2002 and the estimated total transmission capacity to Florida is now closer to 3.5 bscfd.³⁰

In response to a Department inquiry on gas availability to the three plants, FP&L responded that the Gulfstream Pipeline (cutting across the state) will supply all of the needs of the Martin Power Plant located further north. This will theoretically free up transportation capacity along the existing FGT network allowing for maintenance of present supplies and the additional future needs of Turkey Point Unit 5.

There are even more important developments that lend credence to the conclusion by FP&L that the Turkey Point project will not reduce gas availability for the existing units. At the present time, there are three proposed projects to construct liquefied natural gas (LNG) receiving and processing plants that will supply natural gas via pipelines to Southeast Florida. For example, on April 13, 2004 the Governor and Cabinet approved easements for two of the projects to cross state lands.^{31, 32}

The two projects are the Tractebel Calypso and AES Ocean Express. These will enter South Florida at points in Broward County. The projects will supply natural gas (often associated with crude oil production) that is presently flared, reinjected, or left in place at distant sources in Africa, the middle east, Trinidad Tobago, etc.³³ Following is a diagram showing the expected path of one of the projects.

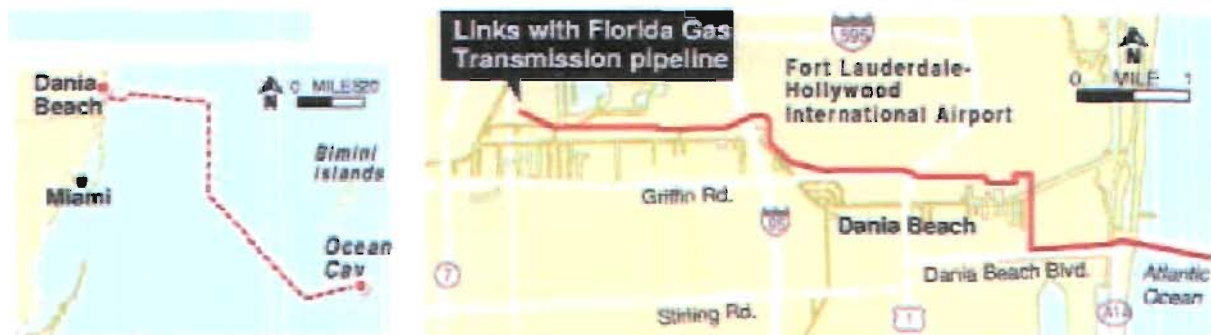


Figure 14. Projected Path of the AES Ocean Express Pipeline (Source: Sun-Sentinel)

El Paso and FPL recently announced agreements for participation of an FPL subsidiary (FPL Group Resources) in the third Bahamas LNG project and pipeline called Seafarer. El Paso and FPL Group Resources announced an agreement for 800 dekatherms per day of capacity on this project.^{34, 35} This project will enter Florida in the area of Riviera Beach.

The total capacity of the three projects will be approximately 2.5 bscfd. The gas need at Turkey Point Unit 5 will be less than 0.2 bscfd. The supply from just one (let alone three) projects is sufficient to overwhelm the needs of the any foreseeable projects in Southeast Florida without impacting usage by the existing units.

In conclusion, the Department accepts that natural gas use at FP&L Turkey Point Unit 5 will not cause increased emissions from the existing residual fuel oil and gas co-fired-fired units in Southeast Florida.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, Residential growth in the area of the proposed project, Miami-Dade County, has increased 47% from 1977 to 2000. The number of vehicle miles traveled has also increased in the county, 58% from 1977 to 2001. During this time period, the number of those employed in the county grew about 71%.

The applicant addressed industrial growth in Miami-Dade County as well. The manufacturing industry has seen a 184% employee increase from 1977-2000 but the agricultural industry saw about a 19% drop in employees (1977-1999). Existing Utility Facilities in Miami-Dade County include the existing FPL Turkey Point Facility, FPL Cutler and the City of Homestead Utility. Currently, other than the expansion at Turkey Point, there are no permits for additional utility growth in the county.

Although, the population and miles traveled in Miami-Dade has increased since 1977, according to the application, air emissions from mobile sources have decreased. Carbon Monoxide has decreased by 61%, VOC has decreased by 65% and Nitrogen Oxides has decreased by 29%. Improvements to automobiles and fuels have more than counteracted any increase in mobile sources in Miami-Dade County.

Despite the growth in Southeast Florida, air quality has improved as evidenced by the redesignation of the Tri-County (Broward, Miami-Dade, and Palm Beach) area to attainment status with respect to the ozone standard.

Endangered Species Considerations

The purpose of the ESA is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species.³⁶ Under the law, species may be listed as either "endangered" or "threatened".

Endangered means a species is in danger of extinction throughout all or a significant portion of its range. Threatened means a species is likely to become endangered within the foreseeable future. All species of plants and animals, except pest insects, are eligible for listing as endangered or threatened.

While state PSD permits are not generally reviewed for adherence with the Endangered Species Act, the State of Florida's Power Plant Certification process requires an assessment of existing ecology and determination of project impacts. Chapter 2 of the Site Certification Application includes a characterization of the existing environment including vegetation, land use and ecology. Chapters 4 and 5 address the effects of construction and operation on ecological systems aquatic and terrestrial ecology. These sections are available at State and local environmental program offices.

According to the U. S. Fish and Wildlife Service (F&WS) website at there were 111 threatened or endangered species (per the federal list) in Florida on May 18, 2004. The reader is referred to the following website: http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=FL

For reference, the F&WS recently noticed the availability of an implementation schedule for the South Florida Multi-Species Recovery Plan designed to restore endangered or threatened animals and plants to the point where they are again secure, self sustaining components of their ecosystems.³⁷

One endangered species of common interest is the American crocodile, the population of which numbers only about 1000 individuals. It lives within and near FP&L's property including the extensive cooling water canals visible in the following aerial photograph.



Figure 15. Cooling Canals at Turkey Pt.



Fig. 16. Crocodile - Everglades National Park

According to FP&L's application, the precise project site is not part of the zone delineating the crocodile habitat, although parts of it can be used by the species. FP&L runs a crocodile management program and stated that it has increased the population of this species. FPL also stated in the application that any loss of potential habitat associated with the project will not jeopardize the continuing existence of the American crocodile or impact the designated habitat.

According to the application, other federally listed endangered species known to occur in Miami-Dade County including several kinds of turtles, the peregrine falcon, the Florida Panther, the manatee, and various plants such as spurge. There is also a State listing that is more extensive than the federal one.

Additional information is given in the separate Department Staff Report prepared in support of the preliminary Siting decision and available from the Department's Siting Office.

10. Preliminary Determination

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the project engineer responsible for preparing the draft BACT determination and the permit as well as evaluating projecting the impacts on fuel supply. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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PERMITTEE:

Florida Power & Light
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:

H. O. Nunez, Plant General Manager

FP&L Turkey Point Fossil Plant
DEP File No. 0250003-006-AC
Permit No. PSD-FL-338
SIC No. 4911
Expires: December 31, 2008

PROJECT AND LOCATION

This permit authorizes the construction of Unit 5 at the existing FP&L Turkey Point Fossil Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will include four 170 MW gas turbine-electrical generator sets, four heat recovery steam generators, a single 470 MW steam turbine-electrical generator, and a mechanical draft cooling tower. The existing FP&L Turkey Point Fossil Plant is located east of Homestead and Florida City and next to Biscayne Bay in Miami-Dade County, Florida. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

- Section I. General Information
- Section II. Administrative Requirements
- Section III. Emissions Units Specific Conditions
- Section IV. Appendices

Michael G. Cooke, Director (Date)
Division of Air Resources Management

SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The existing Turkey Point Fossil Plant currently consists of two fossil fuel-fired steam electrical generating units and five “Black Start” diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The proposed “4 on 1” combined cycle Unit 5, which will consist of four gas turbines (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. New combined cycle Unit 5 will have a total generating capacity of approximately 1150 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
005	Unit 5A gas turbine (170 MW) with supplementary-fired heat recovery steam generator
006	Unit 5B gas turbine (170 MW) with supplementary-fired heat recovery steam generator
007	Unit 5C gas turbine (170 MW) with supplementary-fired heat recovery steam generator
008	Unit 5D gas turbine (170 MW) with supplementary-fired heat recovery steam generator
009	One distillate fuel oil storage tank for Unit 5 gas turbines
010	Mechanical draft cooling tower for Unit 5

Note: FPL Turkey Point Fossil Plant Unit 5 consists of four gas combustion turbine-electrical generator sets (Units 5A-5D), four supplementary gas-fired heat recovery steam generators (HRSGs), and a single steam turbine-electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is potentially subject to 40 CFR 63, Subpart YYYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. (Note: See Appendix YYYYY of this draft permit)

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as “attainment,” “maintenance,” or “unclassifiable” for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a “fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input”, which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

SECTION I. GENERAL INFORMATION

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Miami-Dade County Department of Environmental Resources Management (DERM), Air Quality Management, 33 Southwest 2nd Avenue, Suite 900, Miami, Florida 33130-1540.

APPENDICES

The following Appendices are attached as part of this permit.

- Appendix A. NSPS Subpart A, Identification of General Provisions
- Appendix BD. Final BACT Determinations and Emissions Standards
- Appendix CF. Citation Format and Definitions
- Appendix Da. NSPS Subpart Da Requirements for Duct Burners
- Appendix GC. General Conditions
- Appendix GG. NSPS Subpart GG Requirements for Gas Turbines
- Appendix SC. Standard Conditions
- Appendix YYYY. NESHAP Subpart YYYY Requirements for Gas Turbines
- Appendix XS. Semiannual NSPS Excess Emissions Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on November 14, 2003;
- Department PSD Application Sufficiency comments dated January 2, 2004;
- Environmental Protection Agency Region 4 letter dated January 15, 2004;
- Department of Interior/NPS letter dated February 27, 2004;
- Sufficiency Responses received March 1, 2004;
- Draft permit package issued on May 28, 2004;
- Comments received regarding draft permit;
- Draft permit revised due to comments; and
- Final order issued by the Siting Board.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]
4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]
6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]
7. Title V Permit Revision: The permittee shall submit an application for a revised Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

This section of the permit addresses the following emissions units.

Emissions Units 005, 006, 007, 008

Description: Emissions units 005, 006, 007, and 008 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate supplementary-fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a generating capacity of 470 MW. The total generating capacity of the "4 on 1" combined cycle unit is approximately 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, PM/PM₁₀, SAM, SO₂ and VOC. Dry Low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system further reduces NO_x emissions.

Stack Parameters: Each HRSG has a stack at least 130 feet tall with a nominal diameter of 19 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics:

<u>Fuel</u>	<u>Heat Input Rate (LHV)</u>	<u>Compressor Inlet Temp.</u>	<u>Exhaust Temp., °F</u>	<u>Flow Rate ACFM</u>
Gas	1,608 MMBtu/hour	59° F	202° F	1,023,872
Oil	1,830 MMBtu/hour	59° F	295° F	1,224,407

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. **BACT Determinations:** Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfuric acid mist (SAM), sulfur dioxide (SO₂) and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
2. **NSPS Requirements:** The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to 290 °F before combustion to increase overall unit efficiency. This will be accomplished by feedwater heat exchangers. [Application; Design]
4. Gas Turbine NO_x Controls
 - a. *DLN Combustion*: The permittee shall operate and maintain the General Electric-DLN 2.6 combustion system (or better) to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_x emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH₃) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_x and NH₃ emissions.
 - d. *Ammonia Storage*: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Design; Rule 62-212.400(BACT), F.A.C.]
5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (5A-5D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_x/MMBtu. {Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.} [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,608 MMBtu per hour when firing natural gas and 1,830 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]
8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
 - a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
 - b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months.
 - c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
 - d. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."
 - e. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.
 - f. *High Power Modes (Peaking and Power Augmentation)*: When firing natural gas and only while practicing duct firing, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. When firing natural gas and only while practicing duct firing, steam may be injected into each gas turbine expansion section to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation," the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total hours of power augmentation plus the total hours of peaking shall not exceed 400 hours per gas turbine during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- a. Continuous compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
- b. Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

- c. The sulfur fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard and Section 24.41.1 of the Miami-Dade County Code shall be demonstrated by conducting tests in accordance with EPA Method 9.
- d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section. Compliance with the SO₂ BACT also insures compliance with Section 24.41.3 of the Miami-Dade County Code.
- e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- f. Each SCR system shall be designed and operated for ammonia slip limit of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "PK" means peaking, "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

[Rule 62-212.400(BACT), F.A.C.]

- 10. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. This is not considered a separate mode of operation with respect to emission limits. When operating in this manner, each unit shall comply with the respective standards given in Condition 9 for each mode of operation indicated therein. [Application]
- 11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. *{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da}* [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

- 12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]
14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]
15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.
- a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*
 - b. For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.
 - c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.
 - d. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

16. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS PERFORMANCE TESTING

17. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "<http://www.epa.gov/ttn/emc/ctm.html>". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

18. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_x, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Stack test data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_x mass rate emissions standards. CO and NO_x emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]
19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_x limits for each method of operation given in Condition 9 above. [Rule 62-212.400 (BACT), F.A.C.]
20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

21. **CEM Systems:** The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_x from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_x standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
- CO Monitors.** The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - NO_x Monitors.** Each NO_x monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NO_x monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - Diluent Monitors.** The oxygen (O₂) or carbon dioxide (CO₂) content of the flue gas shall be monitored at the location where CO and NO_x are monitored to correct the measured emissions rates to 15% oxygen. If a CO₂ monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
 - 1-Hour Block Averages.** Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0%

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_x as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

- e. *24-hour Block Averages:* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_x emissions depending on the use of alternate methods of operation}.* [Rule 62-212.400(BACT), F.A.C.]
- f. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- g. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

- 22. *Ammonia Monitoring Requirements:* In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_x emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_x monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

RECORDS AND REPORTS

23. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
24. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
25. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.
- Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.
 - Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.
- The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]
26. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]
27. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_x emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown. An example of the report is provided on Appendix XS. [40 CFR 60.7]

28. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards. Such information shall also be summarized for startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

Draft

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
009	One distillate fuel oil storage tank for Unit 5 gas turbines (approximately 4.2 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.; and Section 24.41.6, Miami-Dade County Code.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 4.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 5 gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. COOLING TOWER (EU 010)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
010	22-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 22-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM₁₀ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM₁₀ per year. Actual emissions are expected be lower than these rates.}* [Rule 62-212.400(BACT), F.A.C.]

SECTION IV. APPENDICES

CONTENTS

Appendix A	NSPS Subpart A, Identification of General Provisions
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix CF	Citation Format and Definitions
Appendix Da	NSPS Subpart Da Requirements for Duct Burners
Appendix GC	General Conditions
Appendix GG	NSPS Subpart GG Requirements for Gas Turbines
Appendix SC	Standard Conditions
Appendix XS	Semiannual NSPS Excess Emissions Report
Appendix YYYY	Reserved for NESHAP Subparts A and YYYY

Draft

SECTION IV. APPENDIX A

NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

- § 60.1 Applicability.
- § 60.2 Definitions.
- § 60.3 Units and abbreviations.
- § 60.4 Address.
- § 60.5 Determination of construction or modification.
- § 60.6 Review of plans.
- § 60.7 Notification and Record Keeping.
- § 60.8 Performance Tests.
- § 60.9 Availability of information.
- § 60.10 State Authority.
- § 60.11 Compliance with Standards and Maintenance Requirements.
- § 60.12 Circumvention.
- § 60.13 Monitoring Requirements.
- § 60.14 Modification.
- § 60.15 Reconstruction.
- § 60.16 Priority List.
- § 60.17 Incorporations by Reference.
- § 60.18 General Control Device Requirements.
- § 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

SECTION IV. APPENDIX BD

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT document issued with initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- Continuous compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.
- Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂.
- The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
- The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
- Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

SECTION IV. APPENDIX BD
FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator _____
New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Date

Approved By:

Michael G. Cooke, Director
Division of Air Resources Management

Date

SECTION IV. APPENDIX CF

CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001" identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

- (119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.
- (179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
- (258) Shutdown - The cessation of the operation of an emissions unit for any purpose.
- (275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 5 gas turbine/HRSG systems, which are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

"Duct burner" means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Gross output" means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM₁₀ emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

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NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil ($\leq 0.05\%$ sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO_2 emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62.297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NO_x) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})] / (O_{sg} \times h) \quad (\text{Equation 1})$$

Where:

- E = Emission rate of NO_x from the duct burner, ng/J (lb/Mwh) gross output
- C_{sg} = Average hourly concentration of NO_x exiting the steam generating unit, ng/dscm (lb/dscf)
- C_{te} = Average hourly concentration of NO_x in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
- Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
- Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
- O_{sg} = Average hourly gross energy output from steam generating unit, J (Mwh)
- h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_x concentrations (C_{sg} and C_{te}). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Q_{sg} and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1-hour runs) for the initial performance tests. Thereafter, compliance with the NO_x limits established in the PSD permit shall demonstrate compliance with NO_x limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

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NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_x standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_x emission rate when demonstrating compliance with the NO_x standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

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GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
 - a. Have access to and copy and records that must be kept under the conditions of the permit;
 - b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
 - c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
 - a. A description of and cause of non-compliance; and
 - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
 - a. Determination of Best Available Control Technology (X);
 - b. Determination of Prevention of Significant Deterioration (X);
 - c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
 - d. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
 - a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - c. Records of monitoring information shall include:
 - 1) The date, exact place, and time of sampling or measurements;
 - 2) The person responsible for performing the sampling or measurements;
 - 3) The dates analyses were performed;
 - 4) The person responsible for performing the analyses;
 - 5) The analytical techniques or methods used; and
 - 6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The Unit 5 gas turbines are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.330 Applicability and Designation of Affected Facility.

Each Unit 5 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

- (a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.
- (b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.
- (d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.
- (g) ISO standard day conditions mean 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.
- (h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.
- (i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.
- (j) Base load means the load level at which a gas turbine is normally operated.
- (q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_x) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

$$\text{STD} = 0.0075 \frac{(14.4)}{Y} + F$$

Where:

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NO_x contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NO_x emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NO_x standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

natural gas) and distillate oil ($\leq 0.05\%$ sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_x standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NO_x emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_x) for each run using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) (\text{Pr}/\text{Po})^{0.5} e^{19(\text{Ho}-0.00633)} (288^\circ\text{K}/\text{Ta})^{1.53}$$

Where:

- NO_x = Emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, volume percent
- NO_{x0} = Observed NO_x concentration, ppm by volume
- Pr = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
- Po = Observed combustor inlet absolute pressure at test, mm Hg
- Ho = Observed humidity of ambient air, g H_2O /g air
- e = Transcendental constant, 2.718
- Ta = Ambient temperature, $^\circ\text{K}$

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_x monitor shall be used to demonstrate compliance with the specified NO_x limits. The permittee is allowed to make the initial compliance demonstration for NO_x emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_x monitor. The permittee is not required to have the NO_x monitor continuously correct NO_x emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

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STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

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11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]
12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
 - a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
 - b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
 - c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.[Rule 62-297.310(4), F.A.C.]
14. Determination of Process Variables
 - a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
 - b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.[Rule 62-297.310(5), F.A.C.]
15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.
16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]
17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]
18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

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sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

- 1) The type, location, and designation of the emissions unit tested.
- 2) The facility at which the emissions unit is located.
- 3) The owner or operator of the emissions unit.
- 4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
- 5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
- 6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
- 7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
- 8) The date, starting time and duration of each sampling run.
- 9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
- 10) The number of points sampled and configuration and location of the sampling plane.
- 11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
- 12) The type, manufacturer and configuration of the sampling equipment used.
- 13) Data related to the required calibration of the test equipment.
- 14) Data on the identification, processing and weights of all filters used.
- 15) Data on the types and amounts of any chemical solutions used.
- 16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
- 17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
- 18) All measured and calculated data required to be determined by each applicable test procedure for each run.
- 19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
- 20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
- 21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION IV. APPENDIX YYYY
NESHAP REQUIREMENTS FOR GAS TURBINES

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant (*Circle One*): SO₂ NO_x TRS H₂S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ¹: _____

Emission data summary ¹	CMS performance summary ¹
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes	1. CMS downtime in reporting period due to: a. Monitor equipment malfunctions b. Non-Monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes
2. Total duration of excess emissions	2. Total CMS Downtime
3. Total duration of excess emissions x (100) / [Total source operating time] % ²	3. [Total CMS Downtime] x (100) / [Total source operating time] % ²

¹ For opacity, record all times in minutes. For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ Date: _____

Title: _____

SECTION IV. APPENDIX YYYY
NESHAP REQUIREMENTS FOR GAS TURBINES

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NSHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O₂). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY. EPA has stayed the applicability of YYYY to units such as those proposed for the Turkey Point project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

According to General Electric, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposes to meet the limit proposed in YYYY of 91 ppmvd.

The very low VOC and CO emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_x technology employed by these units insure that formaldehyde emissions will be at the lowest end of the spectrum.

Any applicable provisions will be included in this section at the time that the Department takes final action on the PSD permit application.

Draft

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

FP&L Turkey Point Fossil Plant
DEP File No. 0250003-006-AC
Permit No. PSD-FL-338

PROJECT DESCRIPTION

The applicant proposes to construct a "4-on-1" 1150 MW combined cycle Unit 8 consisting of the following equipment and specifications: four 170 MW gas turbine-electrical generator sets; four supplementary gas-fired heat recovery steam generators (495 MMBtu/hour, LHV); a common steam-electrical generator (470 MW); a mechanical draft cooling tower; and other associated support equipment. Each gas turbine will fire natural gas as the primary fuel and ultra low sulfur distillate oil as a restricted alternate fuel (≤ 500 hours/year). Additional equipment includes four 131-foot stacks, an aqueous ammonia storage tank, and a distillate fuel oil storage tank.

CO, PM/PM₁₀, and VOC will be minimized by the efficient, high-temperature combustion of natural gas and distillate oil. Emissions of SAM and SO₂ will be minimized by firing natural gas and use of ultra low sulfur ($<0.0015\%$ sulfur) distillate fuel oil. NO_x emissions will be reduced with dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_x controls, a selective catalytic reduction (SCR) system further reduces NO_x emissions. These controls are determined to represent the Best Available Control Technology (BACT). The following limited alternate methods of operation are allowed: duct burning (DB, 2880 hours per year); power augmentation or peaking (≤ 400 hours/year). The draft permit includes the following standards for emissions of CO, NO_x, VOC, and ammonia.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr	ppmvd @ 15% O ₂
CO	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
NO _x	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia	Oil/Gas	CT, All Modes	5	NA	NA

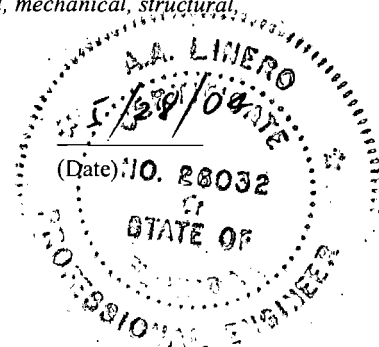
I HEREBY CERTIFY that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).



Alvaro A. Linero, P.E.

Registration Number: 26032

Florida Department of Environmental Protection
Division of Air Resources Management, Bureau of Air Regulation
2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400



Memorandum

Florida Department of Environmental Protection

TO: Trina L. Vielhauer
FROM: A.A. Linero *A.A. Linero 5/25*
DATE: May 25, 2004
SUBJECT: FPL Turkey Point 1,150 MW Expansion Project
DEP File No. 025003-006-AC (PSD-FL-338)

Attached is the draft permit package for FPL Turkey Point Power Plant Unit 5. The project consists of a "four on one" gas-fired combined cycle base load unit with a total capacity of 1,150 megawatts. The site is located near the Class I Everglades National Park and is adjacent to the Class II Biscayne National Park.

Each Heat Recovery Steam Generator will be equipped with a large duct burner for supplemental firing to boost steam production.

Nitrogen Oxides (NO_x) emissions will be controlled by SCR to 2.0 parts per million at 15 percent oxygen (ppmvd @15%O₂) on a 24-hr basis when firing natural gas. This is the lowest value yet in the Southeast. Emissions when firing fuel oil will be 8 ppmvd@15% O₂.

Carbon monoxide (CO) will be controlled to 4.1 and 8.0 ppmvd @15% O₂ when burning natural gas and fuel oil respectively. These are the lowest values yet for projects without the use of oxidation catalyst. Working with FP&L we were able to get GE to guarantee these limits for the first time that I am aware of. There are allowances for the duct burners when used, and power augmentation (steam injection) and peaking.

VOC, SO₂, sulfuric acid mist and particulate matter emissions will be inherently low due to the use of inherently clean fuels. FP&L has committed to use ultra low sulfur (0.0015% S) fuel oil for backup purposes 500 hours per year per unit.

We have set an ammonia limit of 5 ppmvd @15% O₂. This not only minimizes particulate formation, but also reduces nitrogen deposition in the Everglades NPS.

There has been considerable consultation over the past year with the NPS. They submitted comments on the application. Their comments and concerns influenced the draft NO_x BACT determination as well as the use of ultra low sulfur fuel oil. We expect further comments between now and when the Site Certification Hearing is held.

We concluded that the project will not cause or contribute to violations of the ambient air quality standards or the Class I increments. I am also comfortable that there will be no adverse impacts on air quality related values (AQRVs) such as visibility. However, we will need to assess any future opinions submitted by the NPS as conclusions regarding AQRVs fall within their purview.

I recommend your approval of the attached package for public distribution.

AAL/aal

Attachments

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603



April 21, 2004

033-7600-0205

Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED

APR 26 2004

BUREAU OF AIR REGULATION

Attention: Mr. A. A. Linero, P.E., Program Administrator

RE: FPL TURKEY POINT FOSSIL PLANT-1150MW COMBINED CYCLE UNIT NO. 5
DEP FILE NO. 0250003-006-AC (PSD-FL-338)
NATIONAL PARK SERVICE COMMENTS

Dear Al:

This correspondence is submitted on behalf of FPL to address the technical aspects of the comments provided to the Department on Turkey Point Unit No. 5, which were dated February 26, 2004 by the National Park Service (NPS), Policy, Planning and Permit Review Branch located in Denver, Colorado. The technical information is presented according to those technical areas where comments were provided.

Best Available Control Technology (BACT) Analysis

NO_x-As discussed in the Sufficiency Responses, responses to 4FDEP Comment 5 and Comment 6, the proposed BACT for NO_x emission limits in the Air Construction/PSD Application for the Project of 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas and 10 ppmvd corrected to 15 percent oxygen when firing distillate fuel oil, 24-hour block averages, are considered appropriate for the project. These limits have been established as BACT on very recent projects and are of the lowest in EPA Region IV. It is recognized that lower NO_x emission limits have been established, but as discussed in the sufficiency responses, the majority of these limits have been established as LAER, a more stringent standard. However, recognizing the close proximity of the Project to the Everglades National Park (ENP) PSD Class I Area, as well as the Biscayne National Park (BNP), FPL proposed at the April 5, 2004 meeting with the Department revised NO_x emission limits of 2.0 ppmvd corrected to 15 percent oxygen when firing natural gas and 8 ppmvd corrected to 15 percent oxygen when firing distillate fuel oil, 24-hour block averages. The consequences of these lower limits are discussed in the technical information provided in response to the NPS comments on the AQRV analysis section, below.

Air Quality Related Values (AQRV) Analysis

Distillate Oil Firing-The emissions and speciation used to determine impacts to AQRVs in the ENP PSD Class I Area of the Project when firing distillate oil are discussed in the text to Appendix A to the Air Construction/PSD Permit Application. For light oil firing, the filterable particulate from the CT was based on the manufacturer guarantee with the "elemental carbon" component being the average emission rates from tests and the "soil" component being the remainder. We feel that this is supported by information from the CT manufacturer, GE which stated that PM emissions are essentially zero from the combustion process and that any PM is a result of other factors. GE's letter was included in the appendix. We feel this is also supported from a combustion standpoint since combustion temperatures are 2,600°F and the combustion temperature of carbon is about 1,200°F. Filterable particulate was also added from the SCR system. This filterable particulate was assumed to be soil. These assumptions are clearly conservative. The condensable emissions from the CT and duct burners are based on the average emission tests from GE and subtracting out

components associated with fuel sulfur. In the GE letter the average condensable emissions are 14 lb/hr with a contribution of 10 lb/hr from fuel sulfur content (0.05 percent). Unit 5 will use ultra low sulfur content light oil (i.e., 0.0015 percent) that will contribute virtually no sulfur components to condensable particulate. The sulfuric acid mist was based on the maximum amount of sulfur in the light oil. It should be noted that emissions of sulfur dioxide, SCR filterable particulate and sulfuric acid mist were determined independently and not adjusted for the total amount of sulfur in the fuel. Therefore, these emissions are overstated and conservative for the analysis. In addition, the ultra low sulfur content light oil will be comparable in quality to natural gas. For example, the maximum SO₂ emissions from burning natural gas at 2 grains/100 scf is about 9 lb/hr per CT, while the SO₂ emissions firing light oil with a sulfur content of 0.0015 percent is about 3 lb/hr. It is likely that the assumed amount of filterable particulate is high since this guarantee is based on 0.05-percent sulfur fuel currently available. This is also supported by tests conducted on four GE Frame 7FA turbines at FPL facilities using 0.05 percent sulfur distillate oil. The median value for 11 test runs was 3.6 lb filterable particulate with an average of 6.5 lb/hr. The 4.8 lb/hr assumed as elemental carbon is conservative for ultra low sulfur content light oil. Moreover, the organic component of the PM emissions was based on the GE information for condensable PM emissions and is much higher than the GE guarantee of organic emissions. Based on the tests performed for Martin Units 8A and 8B, there are virtually no organic emissions when firing distillate oil in a GE Frame 7FA turbine. The organic emissions were only 0.1 ppmvw compared to a guarantee of 3.5 ppmvw and would produce emissions of about 0.02 lb/hr. The organic condensable PM emission rate used in the modeling was 4 lb/hr. Taking together the conservative assumptions of filterable and condensable PM emissions when firing ultra clean distillate oil, we believe the AQRV analysis was very conservative and based on the latest information.

Natural Gas Firing- Regional haze modeling was performed for power augmentation with duct firing at 360 MMBtu/hr and a turbine inlet of 80°F. This mode of operation, although limited to 400 hours per year, produces the highest combination of particulate matter, sulfur dioxide and nitrogen oxide emissions that will result from operation on natural gas. This information was presented in Tables A-19 and A-20 of Appendix A to the Air Construction/PSD Application. Operating conditions and emissions in Tables A-1 and A-2 of Appendix A to the Air Construction/PSD Application are based on base load operation including duct firing at 550 MMBtu/hr. While a single combustion turbine/heat recovery steam generator (CT/HRSG) train could operate under this condition, all 4 CT/HRSG trains cannot. This is because the 550 MMBtu duct firing reflects the operation of the Project with one CT/HRSG train inoperable. Operating in this condition with only 3 CT/HRSG trains will have lower overall emissions than 4 CT/HRSG trains operating under power augmentation and duct firing at 360 MMBtu/hr.

PM₁₀ Emissions- The speciation of particulate matter used in the Regional Haze modeling is shown in Tables A-19 and A-20 of Appendix A to the Air Construction/PSD Application for natural gas and light oil firing and we believe it reflects the best technical information related to the GE Frame 7FA CT in combined cycle mode and is conservative. For natural gas firing, the filterable particulate from the CT was based on "soil". This is supported by information from the CT manufacturer, General Electric (GE) which stated that PM emissions are essentially zero from the combustion process and that any PM is a result of other factors. GE's letter was included in Appendix A to the Air Construction/PSD Application. From a combustion standpoint the DLN combustion process pre-mixes the natural gas and air. The pre-mixing of the fuel and air, along with combustion temperatures of 2,600°F, suggests that combustion components such as "elemental carbon" would not occur. Indeed, the combustion temperature of carbon is about 1,200°F. For emissions from the duct burner, it was assumed that all filterable particulate was elemental carbon. Filterable particulate was also added from the SCR system. This filterable particulate was assumed to be soil. The condensable emissions from the CT and duct burners are based on manufacturer

guarantees. The sulfuric acid mist was based on the maximum amount of sulfur in the natural gas. It should be noted that emissions of sulfur dioxide, SCR filterable particulate and sulfuric acid mist were determined independently and not adjusted for the total amount of sulfur in the fuel. Therefore, these emissions are overstated and conservative for the analysis. In addition, the organic component of the PM emissions was based on the GE guarantee for condensable PM emissions, which we believe is very conservative. Based on the tests performed for Martin Units 8A and 8B, there are virtually no organic emissions when firing natural gas in a GE Frame 7FA turbine. The organic emissions were below the detection limit of the method (0.1 ppmvw) and would produce emissions of less than 0.01 lb/hr. The organic condensable PM emission rate used in the modeling was 2.38 lb/hr. Taking together the conservative assumptions of filterable and condensable PM emissions when firing natural gas, we believe the AQRV analysis was very conservative and based on the latest information. Technical information was provided above for distillate oil firing.

Natural Gas Firing Peak Load-See information related to natural gas firing.

Cumulative Source Modeling- The detailed stack, operating, and emission data for the facilities with SO₂ and PM₁₀ sources presented in Tables 6-3 and 6-4 are provided in Tables D-1 and D-2 of Appendix D to the Air Construction Permit/PSD Application, Appendix 10.1.5. These data were based on information provided from FDEP, available from recent PSD permit applications, Title V permits, and supplemented with current and historical information available within Golder. The air modeling data were obtained from several recently submitted and reviewed air permit applications in which PSD Class I increment or significant impact analyses were performed at the Everglades National Park. These applications include the modifications to U.S. Sugar Corporation's Clewiston Mill (proposed Boiler No. 8, March 2003; Boiler No. 4 and Sugar Refinery, October 2000); Palm Beach Power Corporation's Cogeneration Facility (April 2002); and FPL's Martin Power Plant Expansion Project, Unit No. 8 (February 2002).

The major source baseline date for Florida is January 6, 1975 for both SO₂ and PM₁₀ (adopted and incorporated by reference in Rule 62-204.800, F.A.C.). The minor source baseline date for SO₂ and PM₁₀ has been set as December 27, 1977 for the entire State of Florida (Rule 62-204.360(1) and (2), F.A.C.).

Based on these baseline dates, the baseline and PSD-increment consuming sources of SO₂ and PM₁₀ emissions for the sources in the inventory were developed from the available information discussed previously. The baseline and PSD increment consuming sources are identified in Tables D-1 and D-2 of Appendix A to the Air Construction/PSD Application.

It should be noted that, although the highest 24-hour average SO₂ concentrations were predicted to exceed 24-hour SO₂ PSD Class I increment for 1990 and 1992, there were no predicted violations of the increment based on the highest, second highest values. Rule 62-272.500 F.A.C. and 40 CFR 52.21(c) support the use of the highest, second highest values when determining compliance with the 24-hour SO₂ PSD Class I increment.

Haze and Coherent Modeling-As discussed above, FPL proposed to the Department NO_x emission limits of 2.0 ppmvd corrected to 15 percent oxygen when firing natural gas and 8 ppmvd corrected to 15 percent oxygen when firing distillate fuel oil, 24-hour block averages. A revised regional haze analysis was performed based on these NO_x emission limits. The basis for the revised analysis is presented in the attached Tables A-19a, 19b and 20a. Please note that an additional scenario was performed for natural gas to reflect the Project under conditions closer to normal operation (i.e., base load with 210 MMBtu/hr duct firing). The results of the revised regional haze analysis are presented in the attached Table ENP-1. Table ENP-1 also presents the previous regional haze

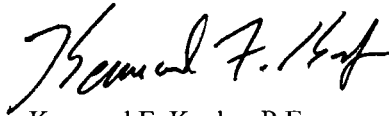
results. As shown in this table, the maximum predicted visibility impacts for the Project were reduced from those previously provided to the Department in the Air Construction/PSD Application. In addition, lowering the NOx emissions for light oil firing has resulted in only one valid value in the three year period that was above 5 percent (i.e., 5.46). The other value, 6.01 percent, was the same period producing the highest regional haze impact in the original analysis. As discussed in the response to 4FDEP Comment 18 in Sufficiency Responses, the value for this period was an artifact of determining relative humidity using Fort Myers and Miami meteorological data. This produced a discontinuity in the northwest corner of the ENP, resulting in the predicted regional haze impacts. Given the updated regional haze impacts and the statistical probability of using light oil during the same periods associated with predicted high regional haze impacts (see response to 4FDEP Comment 18 in Sufficiency Responses); we believe that no significant impacts will occur in the ENP due to the Project.

We believe that the use of VISCREEN for determining plume impacts in the BNP is inappropriate for use at these distances and type of source. VISCREEN is a screening technique that only takes into account emissions of a source, such as PM and NOx, and not other factors that can affect near-field visibility, such as the exhaust gas volume flow from a source. The emissions from the Project will not only be extremely low in quantity but, due to the high volume flow, the emissions will be very dispersed in the high volume exhaust gases. These combined factors result in virtually no visible plume when firing distillate oil. This has been verified through numerous visible emission tests at similar facilities. Moreover, the use of ultra low sulfur light oil, with fuel quality similar to natural gas, would be expected to have even a lower potential for visible emissions. In addition, light oil will only be used as a backup fuel in the event that natural gas is not available for a limited period resulting in an even lower potential for any plume visibility impacts in the BNP.

The opportunity to provide this information is appreciated. We have transmitted the modeling results by e-mail to Ms. Deborah Nelson of your staff including a FTP link to the modeling files. Please call if there are any questions on this technical information.

Sincerely,

GOLDER ASSOCIATES INC.



Kennard F. Kosky, P.E.
Principal

KFK/

Enclosures

cc: Barbara Linkiewicz, FPL
John Gnecco, FPL
H. O. Nunez, Turkey Point Plant

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Table 19a. GAS FIRING - COMBINED CYCLE (Emissions are per CT; 4-CT/HRSG in Project)
CALPUFF Emissions 80 °F Inlet Fogged Power Augmentation (360 MMBtu/hr)

PM	Source	Rate (lb/hr)	Soil	Elemental Carbon (EC)	H ₂ SO ₄	Organic
Filterable	CT	9	9	0		
	DB	1.8	0	1.8		
	SCR	2.03	2.03			
Condensible	CT	3.5			1.01	2.49
	DB	1.8			0.20	1.60
Total PM ₁₀		18.13	11.03	1.8	1.21	4.09
		100.00%	60.83%	9.93%	6.68%	22.56%
Extinction Factor			1.00	10.00	6.00	4.00
Total Relative Extinction Factor		52.65	11.03	18.00	7.26	16.36
		100.00%	20.94%	34.19%	13.79%	31.08%

Notes: DB emissions based on 0.005 lb/MMBtu for both filterable and condensible.
CT filterable is soil based on GE data and information; GE stated that no PM from combustion process (i.e., no EC).
DB filterable assumed to be EC.
H₂SO₄ based on direct calculation and apportioned based on heat input.
GE emission estimates:

			Average Rate (lb/hr)
	Filterable (Front Half)		4.8
	Condensible (Back Half)		2.8
	Total (Front and Back Half)		7.6
	Rate (lb/hr)		
Other Pollutants Modeled	1 CT	4 CTs	
SO ₂ :	12.1	48.4	
NO _x :	19.3	77.2	
Stack Parameters for Modeling			
Temperature	°F	188	
Velocity	ft/s	56.8	
Diameter	ft	19	
Height	ft	131	

Particle Size Distribution (NPS Nov. 2002)

Species Name	Geometric Mass (microns)	Cumulative Size Distribution (%)	Distribution by Category (%)	Emission Rate (lb/hr)	
				1 CT	4 CTs
PM (Total PM ₁₀ - H ₂ SO ₄)			100	16.9	67.7
PM0005	0.05	15	15	2.54	10.15
PM0010	0.10	40	25	4.23	16.92
PM0015	0.15	63	23	3.89	15.56
PM0020	0.20	78	15	2.54	10.15
PM0025	0.25	89	11	1.86	7.44
PM0100	1.00	100	11	1.86	7.44

Table 19b. GAS FIRING - COMBINED CYCLE (Emissions are per CT; 4-CT/HRSG in Project)
CALPUFF Emissions Base Load 59 °F with Duct Firing 210 MMBtu/hr

PM	Source	Rate (lb/hr)	Soil	Elemental Carbon (EC)	H ₂ SO ₄	Organic
Filterable	CT	9	9	0		
	DB	1.8	0	1.8		
	SCR	1.84	1.84			
Condensible	CT	3.5			0.92	2.58
	DB	1.8			0.18	1.62
Total PM ₁₀		17.94	10.84	1.8	1.1	4.2
		100.00%	60.43%	10.03%	6.13%	23.41%
Extinction Factor			1.00	10.00	6.00	4.00
Total Relative Extinction Factor		52.24	10.84	18.00	6.60	16.80
		100.00%	20.75%	34.45%	12.63%	32.16%

Notes: DB emissions based on 0.005 lb/MMBtu for both filterable and condensible.
CT filterable is soil based on GE data and information; GE stated that no PM from combustion process (i.e., no EC).
DB filterable assumed to be EC.
H₂SO₄ based on direct calculation and apportioned based on heat input.
GE emission estimates:

			Average Rate (lb/hr)
	Filterable (Front Half)		4.8
	Condensible (Back Half)		2.8
	Total (Front and Back Half)		7.6
	Rate (lb/hr)		
Other Pollutants Modeled	1 CT	4 CTs	
	SO ₂ :	11.0	44.0
	NO _x :	15.9	63.6
Stack Parameters for Modeling			
Temperature	°F	188	
Velocity	ft/s	59.2	
Diameter	ft	19	
Height	ft	131	

Particle Size Distribution (NPS Nov. 2002)

Species Name	Geometric Mass (microns)	Cumulative Size Distribution (%)	Distribution by Category (%)	Emission Rate (lb/hr)	
				1 CT	4 CTs
PM (Total PM ₁₀ - H ₂ SO ₄)			100	16.8	67.4
PM0005	0.05	15	15	2.53	10.11
PM0010	0.10	40	25	4.21	16.84
PM0015	0.15	63	23	3.87	15.50
PM0020	0.20	78	15	2.53	10.11
PM0025	0.25	89	11	1.85	7.41
PM0100	1.00	100	11	1.85	7.41

Table 20a. OIL FIRING - COMBINED CYCLE (Emissions are per CT; 4 CT/HRSG in Project)
CALPUFF Emissions 35 °F Inlet Baseload

PM	Source	Rate (lb/hr)	Soil	Elemental Carbon (EC)	H ₂ SO ₄	Organic
Filterable	CT	17	12.2	4.8		
	DB	0	0	0		
	SCR	0.63	0.63			
Condensible	CT	4.62			0.62	4.00
	DB	0				0.00
Total PM ₁₀		22.25	12.83	4.8	0.62	4
		100.00%	57.66%	21.57%	2.79%	17.98%
Extinction Factor			1.00	10.00	6.00	4.00
Total Relative Extinction Factor		80.55	12.83	48.00	3.72	16.00
		100.00%	15.93%	59.59%	4.62%	19.86%

Notes: CT filterable is soil based on GE data and information; 4.8 lb/hr is 50% of average front-half test data.

Condensable based on GE average rate and subtracting the effect of 0.05% sulfur fuel.

H₂SO₄ based on direct calculation and apportioned based on heat input.

GE emission estimates:

			Average Rate (lb/hr)	
	Filterable (Front Half)		9.5	
	Condensible (Back Half)		4	14 lb/hr minus sulfate of 10 lb/hr
	Total (Front and Back Half)		13.5	
	Rate (lb/hr)			
Other Pollutants Modeled	1 CT	4 CTs		
SO ₂ :	3.1	12.4		
NO _x :	64.6	258.4		
Stack Parameters for Modeling				
Temperature	°F	297		
Velocity	ft/s	75.5		
Diameter	ft	19		
Height	ft	131		

Particle Size Distribution

Species Name	Geometric Mass (microns)	Cumulative Size Distribution (%)	Distribution by Category (%)	Emission Rate (lb/hr)	
				1 CT	4 CTs
PM (Total PM ₁₀ - H ₂ SO ₄)			100	21.63	86.5
PM0005	0.05	16	16	3.46	13.84
PM0010	0.10	48	32	6.92	27.69
PM0015	0.15	72	24	5.19	20.76
PM0020	0.20	85	13	2.81	11.25
PM0025	0.25	93	8	1.73	6.92
PM0100	1.00	100	7	1.51	6.06

Table ENP-1. Maximum Predicted 24-Hour Visibility Impairment^a at the Everglades National Park
for FPL Turkey Point Emission Scenarios (04/04)

Emission Case	Duct Firing (MMBtu/Hr)	Visibility Impairment (percent) for Year			Visibility Criteria (percent)
		1990	1992	1996	
<u>Natural Gas Firing</u>					
Power Augmentation 80 °F	360	3.32 (3.75)	3.74 (4.02)	3.85 (3.88)	5
Base Load, 59 °F	210	3.26	3.53	3.51	5
<u>Fuel Oil Firing</u>					
Base Load, 35 °F	none	4.42 (5.01)	4.81 (5.26)	6.01 ^b (7.1)	5

^a Predicted with Calpuff Model and south Florida CALMET Domain for 1990, 1992, and 1996.
Based on NO_x emissions of 2 ppmvd corrected to 15% oxygen when firing natural gas and
8 ppmvd corrected to 15% oxygen when firing light oil.

^b Next highest value was 5.64.

Notes: Value within () indicates previous results in PSD analysis submitted 11/03.



United States Department of the Interior

NATIONAL PARK SERVICE

Air Resources Division

P.O. Box 25287

Denver, CO 80225

IN REPLY REFER TO:

February 27, 2004

N3615 (2350)

A.A. Linero, P.E., Administrator
Department for Environmental Protection
New Source Review Section
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
MAR 04 2004
BUREAU OF AIR REGULATION

Dear Mr. Linero:

We have reviewed the Florida Power & Light's (FP&L) Turkey Point Power Plant Prevention of Significant Deterioration (PSD) permit application. FP&L proposes to construct and operate a 1,150 MW combined cycle unit at the existing Turkey Point Power Plant located 21 kilometers east of Everglades National Park (NP) and adjacent to Biscayne NP. Everglades NP is a Class I air quality area and Biscayne NP is a Class II air quality area, both areas are administered by the National Park Service (NPS). The combined cycle unit (called Unit 5) will consist of four General Electric (GE) 7FA combustion turbines and associated electric generators, four heat recovery steam generators and a single steam turbine with associated electric generator and a cooling tower. Emissions from the proposed facility will be 387 tons per year (TPY) of nitrogen oxides (NO_x), 419 TPY of particulate matter (PM), 218 TPY of particulate matter less than 10 microns in size (PM₁₀), 191 TPY of sulfur dioxide (SO₂), 57 TPY of volatile organic compounds, and 19 TPY of sulfuric acid mist.

Based on our review of the permit application, we find that the proposed emissions from the Turkey Point facility may significantly impact visibility at Everglades NP and Biscayne NP. FP&L conducted a haze analysis for areas in Everglades NP greater than 50 kilometers (km) from the proposed facility and a coherent plume analysis for distances less than 50 km. Generally for Class I areas, NPS considers haze impacts from a proposed source as significant if the impacts exceed a 5% change in extinction. If a proposed source has significant haze impacts (i.e., greater than 5% change) on a Class I area, the NPS then determines whether or not those impacts are adverse, based on the frequency, magnitude, and duration of the impacts. The FP&L modeling results provided in its application show, when using fuel oil, there will be four days over three years with impacts over 5% change in extinction, with a maximum impact of 7.1% change in extinction, at Everglades NP. There will be no days over the haze threshold at the park when the facility burns natural gas. The coherent plume analysis did not show any

significant impacts at Everglades NP. FP&L did not conduct a coherent plume analysis for Biscayne NP because it is a Class II area, however our analysis shows there will be plume impacts at Biscayne NP when the proposed facility is burning fuel oil. Because there are impacts above our significant haze impact threshold at Everglades NP and plume impacts at Biscayne NP, we ask that FP&L look at mitigating measures to reduce emissions. In this regard, we have the following comments regarding the Best Available Control Technology (BACT) analysis and air quality related value (AQRV) analysis conducted by FP&L.

BACT Analysis

We continue to support the concept of generating electricity using clean and efficient combined cycle gas turbine technology as proposed by FP&L. Nonetheless, the proximity of the project to Everglades NP and Biscayne NP and potential significant impacts at these parks dictates a rigorous approach to minimizing emissions.

NO_x: FP&L proposes to use Selective Catalytic Reduction with a limit of 2.5 ppm NO_x when burning natural gas, and 10.0 ppm NO_x when burning fuel oil. We would appreciate having the proposed averaging times explicitly defined. While we applaud FP&L for proposing such relatively low limits, we are aware that other similar combustion turbines have proposed, or been permitted at lower limits. For example, the enclosed Table 1 shows seventeen combustion turbines with NO_x limits at 2.0 ppm or less while burning natural gas, while Table 2 shows seven combustion turbines with less than 10.0 ppm NO_x when burning fuel oil. We are also aware of actual test results showing NO_x emissions of less than 1.0 ppm when firing natural gas in a combustion turbine.¹ FPL should demonstrate why it cannot meet the same lower limits as its competitors.

SO₂: We are pleased that FP&L proposes to burn gas and ultra-low sulfur oil (0.015%) and consider this BACT for SO₂.

AQRV Analysis

FP&L did not explain how the single-source stack parameters were developed. Based on what we reviewed, it appears that Case 28, Distillate Oil, Base Load at 35° F produces the greatest emissions of PM₁₀, SO₂, NO_x, and sulfates (SO₄) when burning fuel oil. However, the method used by FP&L to speciate particulate does not follow the guidance we have posted on our website and is not adequately explained. Our best estimate of emissions from oil firing is contained in the enclosed Table 3.

Natural Gas Firing--Base Load: It appears that Case 7, Natural Gas, Base Load at 35° F produces the greatest emissions of PM₁₀, SO₂, NO_x, and SO₄ when operating in a base load mode, and was the basis for the emission entries on the application forms for normal

¹ "Test Report, Compliance Emissions Testing, Lake Road Generating Company, L.P.," Killingly, CT, by TRC Environmental Corporation February 2002.

operation. However, the emission rates presented for this case in FP&L's Tables A-1 and A-18 do not match, and it is not clear if this case was modeled.

PM₁₀ Emissions: With regard to the PM₁₀ emissions, FP&L presents a June 17, 2003, letter from GE. In the letter the turbine vendor argues that "PM₁₀ emissions from its 7FA natural gas-fired units are essentially zero (no emissions from the combustion process itself). Therefore it is impractical to speciate PM₁₀ emissions from the combustion process." GE goes on to suggest that airborne PM₁₀, inert solids in natural gas, construction debris, rust, and measurement artifacts are all sources of the turbine PM₁₀ filterable emissions. Sources of condensable PM₁₀ consist of formation of ammonia sulfates from the SCR system, sulfates, unburned hydrocarbons, and other undefined condensibles. GE's argument could be true if these turbines could achieve complete combustion, and the resulting emission products were carbon dioxide and water. However, the GE letter appears internally inconsistent because, while arguing that its turbines have zero PM₁₀ emissions from the combustion process, it cites "unburned hydrocarbons" as a source of condensable emissions. Furthermore, the Turkey Point facility will emit substantial amounts of carbon monoxide, volatile organic compounds, and formaldehyde, all of which are products of incomplete combustion. Finally, FP&L's assumption that most filterable PM₁₀ is due to airborne soils would require airborne dust concentration in excess of the National Ambient Air Quality Standards (NAAQS). For example, if the ambient PM₁₀ levels are just at the 24-hour NAAQS, at the flow rate given for these turbines, PM₁₀ emissions due to airborne PM₁₀ would be less than 0.5 lb/hr. While it is likely that much of the condensable PM₁₀ attributed to gas-fired turbines is an artifact of the measurement process, the same would not hold for the filterable component. For these reasons, we suggest that FP&L model the emissions shown in Table 3.b. for this operating scenario.

Natural Gas Firing Peak Load: With regard to natural gas firing during peak load or during power augmentation or high power mode, FP&L presents one or more operating scenarios described as:

- Power Augmentation in Tables A-1 and A-2 (titled "Base Load"), and A-19;
- described as Peak in Tables A-7, A-8 (both titled "Peak Load"), and in Table A-18 (also titled "Base Load"); and
- described as "High Power Mode" (HPM) on the application form page pertaining to NO_x.

However, the emission rates in Tables A-2 and A-19 do not match, nor do the emission rates in Tables A-7 and A-8 match those in A-18. The only match was a pairing of SO₂ and NO_x emission rates in Tables A-18 Peak and A-19 Power Augmentation. Table A-19 appears to be an attempt at speciating the PM₁₀ emissions during power augmentation, but has the same problems as noted above. Since the high peak mode may have NO_x emission of over 105 lb/hr, FP&L should explain how these emissions were modeled.

Case 28 represents the maximum emissions from oil firing and the high power mode represents the maximum emissions from gas firing, both of these cases should be modeled. However, it appears from the application (p. 6-7) that only the scenarios contained in Tables 2-1 and 2-2 were modeled. While this would capture emissions from

Cases 7 and 28 it does not include emissions from the High Power Mode and underestimates from those impacts. Furthermore, the errors in particle speciation may also be significant.

Cumulative Source Modeling: Regarding the cumulative-source modeling parameters, FP&L provides no description of how the emission inventories presented in Tables 6-3 and 6-4 were prepared, nor are any emission rates given. FP&L should provide all applicable baseline dates for Everglades NP, a description of its methodology for compiling the inventory, and the emission rates used in its analyses. Without this information, we cannot draw any conclusions regarding the completeness of the cumulative source analyses. However based on what we reviewed in the FP&L application, we are concerned with the results from the cumulative 24-hour SO₂ Class I increment analysis. Both the 1990 and 1992 cumulative analyses indicate the 24-hour Class I increment was exceeded with values greater than 5.0 µg/m³, and the 1996 analysis highest impact was 4.8 µg/m³. Therefore, we ask FP&L to provide more information regarding their SO₂ Class I inventory.

Haze and Coherent Plume Modeling: The haze analysis indicates that the Turkey Point project will impact Everglades NP with impacts of greater than a 5% change once each year using the 1990 and 1992 meteorological data and twice using the 1996 meteorological data. Based on the frequency and magnitude of the haze impacts, we do not request that a cumulative haze analysis be performed.

The coherent plume analysis was conducted with the Environmental Protection Agency VISCREEN model at Level 2. We do not believe that the oil firing scenario was modeled correctly with respect to the speciation of the PM emissions and lack of a "soot" component. The NPS re-modeled the oil fired scenario for impacts to Everglades NP with a corrected PM emission rate and included the "soot" particulate. This analysis indicates that the Turkey Point project will not have a coherent plume impact under the same "worst case" 1% meteorological condition of "D" atmospheric stability and a wind speed of 4.4 meters per second (m/sec). With regard to Biscayne NP, which is adjacent to the proposed Turkey Point facility, we performed a VISCREEN analysis for the oil fired scenario and the corrected PM speciation. This analysis indicates visible plume impacts to Biscayne NP beyond the "worst case" 1% meteorological conditions used in the Everglades analysis. Based on these calculations, there could be plume impacts at Biscayne NP when winds are from the south and the FP&L facility is burning fuel oil.

Conclusions

In conclusion, we request that FP&L show why it cannot meet a 2.0ppm NO_x limit on a one-hour average basis as is required in the Ivanpah permit. Averaging times for the proposed emission limits should also be specified. FP&L should clarify the nature of the operating scenarios modeled and rationalize the inconsistencies noted above. They should either provide a better justification of their approach to particle speciation or use the default approach provided by NPS. We also ask that FP&L describe the High Power Mode and justify its exclusion from the modeling analysis. Finally, because FP&L's

cumulative SO₂ impact analysis shows Class I increment exceedences, FP&L should provide all applicable baseline dates for Everglades NP, a description of its methodology for compiling the cumulative emissions inventories, and the emission rates used in its analyses. We also ask FP&L to send us all of the CALMET input files used in its modeling analysis.

Given the proximity of the Turkey Point facility to Everglades NP and Biscayne NP, we ask that FP&L look at mitigating measures to reduce emissions and the corresponding impacts in these parks. Thank you for involving us in the review of the PSD permit application for the Turkey Point facility. Please do not hesitate to contact me at (303) 969-2817 if you have questions concerning our comments.

Sincerely,

A handwritten signature in black ink, appearing to read "Darwin W. Morse". The signature is fluid and cursive, with a long horizontal line extending from the end.

Darwin W. Morse
Environmental Protection Specialist
Policy, Planning and Permit Review Branch

Enclosures

Table 1. Combined Cycle Turbines <2.5ppm on

<i>State</i>	<i>Facility Name</i>	<i>Type</i>	<i>Total MW</i>	<i>Gas (ppm)</i>	<i>NOx Control</i>
AZ	Toltec Power Station	GE Frame 7 FA	1200	2	SCR
CA	Sunlaw Cogen	GE LM2500-M-2	28	2	Dry Low NOx
CA	Calpine-Inland Empire Energy	GE Frame 7 FB	670	2	SCR
CA	Mountain View Power	GE Frame 7 FA	1991	2	SCR
CA	Nueva Azalea		550	1	SCONOx
CA	Intergen-Ocotillo	GE Frame 7 FA		2	SCR
CA	Magnolia Power	GE Frame 7 FA	250	2	SCR
CA	Magnolia Power	Westinghouse 501F	250	2	SCR
CT	Lake Road Generating			2	SCR
EPA	Teayawa		600	2	SCR
MA	ANP Blackstone	ABB GT-24		2	SCR
NV	Diamond Gen-Ivanpah	Westinghouse 501FD	500	2	SCR
NV	Las Vegas Cogen	GE LM 6000 Aero PC	240	2	SCR
VA	Tractebel--Loudoun Energy Center	SW 501G	1400	2	SCR
VA	CPV-Warren Co.	GE Frame 7 FA	520	2	SCR
WA	Goldendale Energy		249	2	SCR
WA	Sumas	Siemens-Westinghouse	669	2	SCR

Table 2. Combined Cycle Turbines <10ppm on Oil

<i>Facility Name/Location</i>	<i>State</i>	<i>Simple/Combined Cycle</i>	<i>Total MW</i>	<i>NOx Control</i>	<i>Type</i>	<i>Oil (ppm)</i>
ANP Blackstone	MA	Combined Cycle		SCR	ABB GT-24	6
Duke Energy-Fayette	PA	Combined Cycle	620	SCR	Ge Frame 7 FA	9
James City Energy	VA	Combined Cycle	580	SCR	GE Frame 7 FA	9
Lake Road Generating	CT	Combined Cycle		SCR		5.9
Santa Rosa Energy LLC	FL	Combined Cycle	241	Dry Low NOx	GE Frame 7 FA	9.8
Sumas	WA	Combined Cycle	669	SCR	Siemens-Westin ghouse	6
Tenaska-Buckingham Co.	VA	Combined Cycle	900	SCR	GE Frame 7 FA	6

Table 3

Table 3.a. Each Turbine

	Combined Cycle			Oil Firing			Steady-State Emissions								
	Filterable PM (NPS Estimate)			Condensible PM (NPS Estimate)			SO2 (Applicant)			SO4 (Applicant)			NOx (Applicant)		
	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)
Soils		3.78	0.48					3.1	0.39094		0.62	0.078189		79.5	10.02583
EC		3.15	0.40												
OC					10.71	1.35									
		6.92	0.87		10.71	1.35									

Turbine Stack Parameters

Unit	Mode	Fuel	Height		Diameter		Temperature		Flow		Velocity	
			ft	m	ft	m	F	K	ft3/min	m3/min	ft/sec	m/sec
#1 - #4	CC	#2	131	39.9	19.0	5.8	295	419	#####	33,832	70.2	21.4

Table 3.b. Each Turbine

	Combined Cycle			Gas Firing			Steady-State Emissions								
	Filterable PM (NPS Estimate)			Condensible PM (NPS Estimate)			SO2 (Applicant)			SO4 (Applicant)			NOx (Applicant)		
	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)
Soils								13.30	1.68		1.33	0.17		24.20	3.05
EC		3.60	0.45												
OC					10.80	1.36									
		3.60	0.45		10.80	1.36									

Turbine Stack Parameters

Unit	Mode	Fuel	Height		Diameter		Temperature		Flow		Velocity	
			ft	m	ft	m	F	K	ft3/min	m3/min	ft/sec	m/sec
#1 - #4	CC	NG	131	39.9	19.0	5.8	202	367	#####	28,456	59.0	18.0

Table 3.c. Each Turbine

	Combined Cycle			Gas Firing			Steady-State Emissions								
	Filterable PM (NPS Estimate)			Condensible PM (NPS Estimate)			SO2 (Applicant)			SO4 (Applicant)			NOx (Applicant)		
	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)	(lb/mmBtu)	(lb/hr)	(gm/sec)
Soils								13.30	1.68		1.33	0.17		105.10	13.25
EC		3.60	0.45												
OC					10.80	1.36									
		3.60	0.45		10.80	1.36									

Turbine Stack Parameters

Unit	Mode	Fuel	Height		Diameter		Temperature		Flow		Velocity	
			ft	m	ft	m	F	K	ft3/min	m3/min	ft/sec	m/sec
#1 - #4	CC	NG	131	39.9	19.0	5.8	205	369	#####	28,757	59.7	18.2

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603



TRANSMITTAL LETTER

**To: Mr. Al Linero
FDEP**

**Date: February 27, 2004
Project No.: 0337600-0105**

Sent by: nav

☐ Mail
☐ Air Freight
☐ Hand Carried

☐ UPS
☒ Federal Express

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MAR 01 2004

BUREAU OF AIR REGULATION

Per: Ken Kosky

Quantity	Item	Description
2	Final Bound Copies	FPL Turkey Point Expansion Project SCA Sufficiency Responses

Remarks:

Please find enclosed 2 copies of the Sufficiency Responses for FPL Turkey Point Expansion Project (Unit 5). The Sufficiency Responses address questions and comments from several offices within the Florida Department of Environmental protection, the Florida fish and Wildlife Conservation Commissions, the South Florida Regional Planning Council, and the South Florida Water Management District. Contact Mr. Steven Palmer of the FDEP Siting Office [(850) 245-8002] for further information or questions.



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

JAN 15 2004

4APT-APB

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JAN 20 2004

BUREAU OF AIR REGULATION

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Thank you for sending the prevention of significant deterioration (PSD) permit application for Florida Power & Light (FPL) Turkey Point, dated November 19, 2003. The PSD permit application is for the proposed construction and operation of four combined cycle combustion turbines (CTs) with a total nominal generating capacity of 1,150 MW to be located near Homstead, FL. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with ultra low sulfur fuel oil (0.0015% S) combusted as backup fuel. As proposed, the CTs will be allowed to fire natural gas up to 8,760 hours per year and fire fuel oil a maximum of 500 hours per year. The CTs will be allowed to operate natural gas-fired duct burners for a maximum of 2,880 hours/year. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO₂), particulate matter (PM/PM₁₀), and volatile organic compounds (VOC).

Based on our review of the PSD permit application we have the following comments:

1. The applicant proposed the use of good combustion practices as best available control technology (BACT) for CO and requested the following CO limits (page 4-2): 9 ppmvd while burning natural gas, 17 ppmvd while burning natural gas and duct firing, 22.6 ppmvd while burning natural gas and in high power mode with duct firing, and 20 ppmvd when burning fuel oil. However, Table 4-1 (page 4-16) of the application references the following CO limits: 7.3 ppmvd while burning natural gas, 10.2 ppmvd while burning natural gas and duct firing, 14.7 ppmvd while burning natural gas and in high power mode with duct firing, and 20 ppmvd when burning fuel oil. According to the vendor test data in Appendix B, the latter set of emission limits seem to be the correct ones.

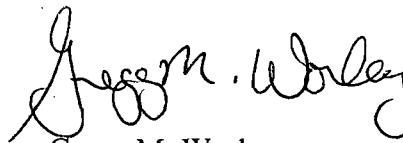
Regardless of which set of emission limits are the correct ones, these CO limits are much higher than those recently seen as a result of BACT analyses throughout the country, including here in Region 4. For instance, we are seeing CO limits for both natural gas and fuel oil combustion in the low single digits (i.e., 2.0 ppmvd) in several recent permits in Georgia. According to the application, the CO emissions test data range from 0.0 ppmvd to 1.01 ppmvd when firing natural gas during load ranges from 50 to 100

percent. Irrespective of the exact control technology used, we would expect to see BACT CO limits near 2 ppmvd in the draft PSD permit for FPL Turkey Point.

2. Table 2-4 is a summary of the maximum potential annual emissions. In several of the scenarios, including the scenario generating maximum CO emissions, it is assumed that there will be a maximum of 400 hours/year of operation with power augmentation. In order for the BACT analysis to remain valid, this limit on power augmentation should be included as an enforceable requirement of the draft PSD permit. Additionally, any other underlying assumptions used in the BACT or air quality analyses, such as the 2,880 hours/year limit on duct burning, should also be included in the draft PSD permit. Finally, any operating limits (including the ones mentioned above) which were used in the analyses on a per CT basis should be included in the draft PSD permit on a per CT basis.
3. The applicant rejected catalytic oxidation as an economically infeasible control technology for reducing CO emissions from the CTs. According to the application, the resulting cost effectiveness was found to be \$4,240/ton of CO removed. The annual operating costs included \$214,193 for a heat rate penalty (0.2 percent of the megawatt (MW) output.) It is unclear if this value is based on a set dollar per kW of lost sales or based on the cost of additional natural gas to make up for the 0.2 percent loss in MW output. The applicant should provide a better explanation of how this number was calculated. Please note that we do not consider it appropriate to calculate a heat rate penalty based on lost sales. It should be calculated based on the cost of enough natural gas to make up for any loss in MW output. The annual heat rate penalty contributes \$1,462/ton of CO removed to the total cost effectiveness. Consequently, any reduction in the heat rate penalty will make a significant difference in the cost effectiveness of catalytic oxidation. Finally, it should be noted that catalytic oxidation has the added advantage of controlling VOC emissions, including volatile organic hazardous air pollutants.

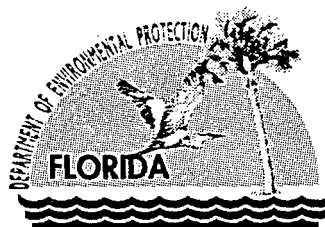
If you have any questions regarding these comments or need additional information, please contact Katy Forney at 404-562-9130.

Sincerely,



Gregg M. Worley,
Chief
Air Permits Section

cc: D. Nelson
J. Little, SED
P. Hong, DERM
B. O'Neil, DEP
Dr. Bunnell, NPS
K. Kordy, Boulder



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

November 19, 2003

Mr. John Bunyak, Chief
Air Quality Division
U.S. National Park Service
Post Office Box 25287
Denver, Colorado 80225

Re: FPL Turkey Point Plant
1150 MW Combined Cycle Project
PSD-FL-338

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the Florida Power & Light (FPL) Turkey Point Unit 5 Project. The site is near the extreme southeast of the peninsula near Florida City, Miami-Dade County. The nearest boundary of the Everglades National Park is approximately 21 kilometers west of the plant. This project will be comprised of four dual fuel GE 7FA combustion turbines with supplementary-fired heat recovery steam generators and a single steam electrical generator. The project will have a nominal generating capacity of 1,150 megawatts (MW net).

Dry Low NO_x (DLN) combustion, Selective Catalytic Reduction (SCR) and use of inherently clean natural gas are the main pollution control measures. Water injection, SCR and use of the new *ultra low* sulfur (0.0015% sulfur) are the main measures when using backup fuel oil.

The applicant proposes NO_x emissions of 2.5 ppmvd while burning natural gas delivered by the interstate pipeline network. For reference the New Source Performance Standard is approximately 108 ppmvd of NO_x. They propose 10 ppmvd of NO_x while burning the new diesel fuel for 500 hours or less per year.

The applicant's estimates of annual emissions of pollutants subject to PSD review are listed in the following table:

Pollutant	Proposed Project Emissions (tons per year)
NO _x	387
SO ₂	191
CO	681
H ₂ SO ₄ Mist	19
PM/PM ₁₀	23
VOC	7

Emissions of the key pollutants with respect to Air Quality Related Values are expected to be approximately 625 tons per year. The pollutant loading will be much less than the some of the new, but smaller, projects near Class I areas in other states that have been reported to be of concern to the Park Service and EPA. The applicant's conclusion is that the project is "unlikely to cause adverse visibility impairment in the Everglades National Park." Their finding is premised on the very low probability of occurrence of the meteorological factors that give rise to any meaningful effects, coupled with the low probability of using the backup *ultra low* sulfur fuel oil at the same time those factors would occur.

"More Protection, Less Process"

Printed on recycled paper.

We have already had two teleconferences with FPL and the Park Service air experts about the project and discussed some of the scenarios and preliminary findings. We look forward to continuing those discussions now that a specific scenario has been proposed in an application. Please let us know of any information requests as soon as possible and we will quickly pass them on to the applicant.

I will be the general contact as well as the contact on air pollution control. Our other contacts are Cleve Holladay (850/921-8986) on matters related to visibility and Debbie Nelson (850/921-9537) on matters related to the ambient standards and increments. If you have any questions, please call me at 850/921-9523.

Sincerely,

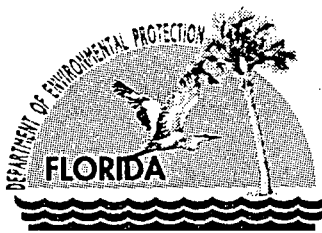


A. A. Linero, P.E. Administrator
New Source Review Section

AAL/al

Enclosure

Cc: Maureen Finnerty, Everglades Superintendent w/o Enclosure



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
November 19, 2003

David B. Struhs
Secretary

Mr. Gregg Worley, Chief
Air Permitting Section
U.S. EPA Region 4
61 Forsyth Street
Atlanta, Georgia 30303

Re: FPL Turkey Point Plant
1150 MW Combined Cycle Project
PSD-FL-338

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the Florida Power & Light (FPL) Turkey Point Unit 5 Project. The site is near the extreme southeast of the peninsula near Florida City, Miami-Dade County. The nearest boundary of the Everglades National Park is approximately 21 kilometers west of the plant. This project will be comprised of four dual fuel GE 7FA combustion turbines with supplementary-fired heat recovery steam generators and a single steam electrical generator. The project will have a total nominal generating capacity of 1,150 megawatts (MW net).

Dry Low NO_x (DLN) combustion, Selective Catalytic Reduction (SCR) and use of inherently clean natural gas are the main pollution control measures. Water injection, SCR and use of *ultra low* sulfur (0.0015% sulfur) are the main measures when using backup fuel oil.

The applicant proposes NO_x emissions of 2.5 ppmvd while burning natural gas delivered by the interstate pipeline network. For reference the New Source Performance Standard is 108 ppmvd of NO_x. They propose 10 ppmvd of NO_x while burning the new diesel fuel for 500 hours or less per year.

The applicant's estimates of annual emissions of pollutants subject to PSD review are listed in the following table:

Pollutant	Proposed Project Emissions (tons per year)
NO _x	387
SO ₂	191
CO	681
H ₂ SO ₄ Mist	19
PM/PM ₁₀	23
VOC	7

Emissions of the key pollutants with respect to Air Quality Related Values are expected to be approximately 625 tons per year. The pollutant loading will be much lower than some of the recent new, but smaller, projects near Class I areas that have been reported to be of concern to the Park Service and EPA. Please send your comments to my attention at the letterhead address (fax: 850/922-6979). If you have any questions, please call me at 850/921-9523.

Sincerely,


A. A. Linero, P.E. Administrator
New Source Review Section

AAL/al
Enclosure

"More Protection, Less Process"

Printed on recycled paper.



FPL

November 14, 2003

Hamilton S. Oven, P.E., Administrator
Office of Siting Coordination
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Turkey Point Expansion Project
Application for Site Certification

Dear Mr. Oven:

Florida Power & Light Company (FPL) is pleased to submit to the Department its Application for Site Certification (SCA) for the Turkey Point Expansion Project, pursuant to the Florida Electrical Power Plant Siting Act and Florida Administrative Code Rule 62-17.051(1)(d). Also enclosed is FPL Check No. 0660495 made payable to the Department in the amount of \$125,000.00 and provided as the application fee pursuant to Florida Administrative Code 62-17.051(2). At this time, we are providing 14 copies of the Application, with 4 of those copies being sent by copy of this letter to the Department's Southeast District Office in West Palm Beach. Upon the Department's determination that the Application is complete, FPL will distribute the Application to the other required recipients.

The SCA addresses the environmental and socioeconomic aspects of the Turkey Point Expansion Project by presenting information in accordance with the Department's "Instruction Guide for Certification Application", DEP Form 62-1.211(1).

FPL looks forward to working with the Department and other interested agencies in the certification process. If you should have any questions regarding our Application, please do not hesitate to call me at 561-691-2216.

Sincerely,

Barbara P. Linkiewicz
Environmental Licensing Manager

cc: Mr. Timothy Gray, FDEP Southeast District Office (4 copies)

SITING COORDINATION

NOV 14 2003

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

APPENDIX 10.1.5

AIR CONSTRUCTION PERMIT AND PSD APPLICATION

**AIR PERMIT APPLICATION AND PREVENTION OF
SIGNIFICANT DETERIORATION ANALYSIS FOR
FPL TURKEY POINT EXPANSION PROJECT
MIAMI-DADE COUNTY, FLORIDA**

**Prepared For:
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408**

**Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500**

**November 2003
0337600**

APPLICATION FOR PERMIT



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: Florida Power and Light Company	
2. Site Name: Turkey Point Power Plant	
3. Facility Identification Number: 0230003	
4. Facility Location...: Street Address or Other Locator: 9.5 miles east of Homestead on SW 344th Street City: Homestead County: Miami-Dade Zip Code: 33035	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: Barbara Linkiewicz, Environmental Licensing Manager, New Generation Projects	
2. Application Contact Mailing Address... Organization/Firm: Florida Power & Light Company Street Address: 700 Universe Blvd. City: Juno Beach State: FL Zip Code: 33408	
3. Application Contact Telephone Numbers... Telephone: (561)691-7518 ext. Fax: (561)691-7049	
4. Application Contact Email Address:	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	11-14-03
2. Project Number(s):	025 0003-006-AC
3. PSD Number (if applicable):	PSD-FL-338
4. Siting Number (if applicable):	PA03-45

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

See PSD Report. Application fee not applicable since review is Site Certification review, which has an application fee.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
5A	GE Frame 7FA Cumbustion Turbine/HRSG	AC1A	
5B	GE Frame 7FA Cumbustion Turbine/HRSG	AC1A	
5C	GE Frame 7FA Cumbustion Turbine/HRSG	AC1A	
5D	GE Frame 7FA Cumbustion Turbine/HRSG	AC1A	
	Cooling Tower	AC1A	

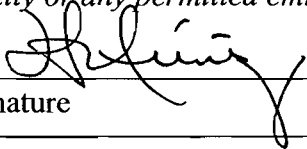
Application Processing Fee

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 : H.O. Nunez - Plant General Manager
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Florida Power & Light, Turkey Point Fossil Plant Street Address: 9700 SW 344th Street City: Homestead State: FL Zip Code: 33035
3. Owner/Authorized Representative Telephone Numbers... Telephone: (305) 242-3822 ext. Fax: (305) 242-3821
4. Owner/Authorized Representative Email Address:
5. Owner/Authorized Representative Statement: <i>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.</i>  _____ Signature <u>11 / 10 / 03</u> _____ Date

APPLICATION INFORMATION

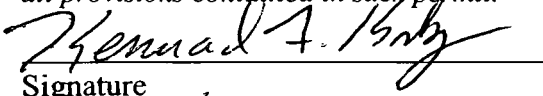
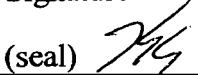
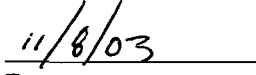
Application Responsible Official Certification

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:		
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: Street Address: City: State: Zip Code:		
4. Application Responsible Official Telephone Numbers... Telephone: () - ext. Fax: () -		
5. Application Responsible Official Email Address:		
6. Application Responsible Official Certification: <i>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.</i> Signature _____ Date _____		

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Kennard F. Kosky Registration Number: 14996
2. Professional Engineer Mailing Address... Organization/Firm: Golder Associates Inc.** Street Address: 6241 NW 23rd Street, Suite 500 City: Gainesville State: FL Zip Code: 32653-1500
3. Professional Engineer Telephone Numbers... Telephone: (352) 336-5600 ext. 516 Fax: (352) 336-6603
4. Professional Engineer Email Address: kkosky@golder.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> (1) <i>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</i> (2) <i>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.</i> (3) <i>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.</i> (4) <i>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.</i> (5) <i>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.</i>  Signature  (seal)  Date

* Attach any exception to certification statement.

** Board of Professional Engineers Certificate of Authorization #00001670

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) North (km)		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment : Project consists of four 170-MW dual fuel, GE Frame 7FA CT/HRSGs that will use dry low-nitrogen oxide combustion technology when firing natural gas and water injection when firing distillate fuel oil, along with selective catalytic reduction (SCR). Each CT/HRSG will operate up to 8,760 hr/yr. Current facility Title V Permit No. 0250003-001-AV.			

Facility Contact

1. Facility Contact Name: Gary Andersen, Environmental Specialist		
2. Facility Contact Mailing Address... Organization/Firm: Florida Power & Light Company, Turkey Point Fossil Plant Street Address: 9700 SW 344th Street City: Homestead State: FL Zip Code: 33035		
3. Facility Contact Telephone Numbers: Telephone: (305) 242-3826 ext. Fax: (305) 242-3821		
4. Facility Contact Email Address:		

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: CT and HRSGs are subject to NSPS Subpart GG and Da, respectively. CT may be subject to NESHAPS Subpart YYYY.	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	N
PM ₁₀	A	N
VOC	A	N
SO ₂	A	N
NO _x	A	N
CO	A	N

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

[illegible]

FACILITY INFORMATION

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: PSD Report ☐ 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: PSD Report ☐ 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: PSD Report ☐ Previously Submitted, Date: _____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: PSD Report ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: ☒ Attached, Document ID: PSD Report
3. Rule Applicability Analysis: ☐ Attached, Document ID: _____
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: PSD Report ☐ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: PSD Report ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☒ Attached, Document ID: PSD Report ☐ 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: PSD Report ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

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 [2]
Units 5A-5D

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:

Four identical GE Frame 7FA CT/HRSGs. Designated as Units 5A, 5B, 5C, 5D.

3. Emissions Unit Identification Number: **5A, 5B, 5C, 5D**

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: **GE**

Model Number: **7FA**

10. Generator Nameplate Rating: **172 MW**

11. Emissions Unit Comment:

This emission unit is a GE Frame 7FA CT/HRSG operating in combined cycle mode – 4 identical units (see PSD Report). Generator nameplate rating based on ISO turbine inlet conditions.

EMISSIONS UNIT INFORMATION

Section [1] of [2]

Units 5A-5D

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Natural Gas

- Combined cycle – SCR

Distillate Fuel Oil

- Water injection
- Combined cycle - SCR

2. Control Device or Method Code(s): **25, 28, 65**

**Section [1] of [2]
Units 5A-5D**

(Optional for unregulated emissions units.)

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate:	1,674 million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 7 weeks/year	52 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:	Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,728 MMBtu/hr and 190.3 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]

Units 5A-5D

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: See PSD Report		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Exhausts through the HRSG stack.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code: V		6. Stack Height: HRSG- 131 ft	
7. Exit Diameter: 19 feet			
8. Exit Temperature: 202 °F		9. Actual Volumetric Flow Rate: 1,004,150 acfm	
10. Water Vapor: 8.4%			
11. Maximum Dry Standard Flow Rate: 800,000 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: Stack parameters for ISO operating conditions firing natural gas above; for oil – 295°F and 1,193,854 ACFM; HPM 205°F and 1,014,759. Note: Stack height may be up to 150 ft. See PSD Report for all stack parameters.			

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 2

1. Segment Description (Process/Fuel Type): Distillate (No. 2) Fuel Oil		
2. Source Classification Code (SCC): 20100101		3. SCC Units: 1,000 Gallons Used
4. Maximum Hourly Rate: 14	5. Maximum Annual Rate: 7,000	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 130
10. Segment Comment: Million Btu per SCC unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV = 18,300 Btu/lb ISO conditions, 500 hr/yr operation.		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Natural Gas		
2. Source Classification Code (SCC): 20100201		3. SCC Units: Million cubic feet
4. Maximum Hourly Rate: 1.68	5. Maximum Annual Rate: 14,754	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 950
10. Segment Comment: Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hr/yr operation.		

**Section [1] of [2]
Units 5A-5D**

List of Pollutants Emitted by Emissions Unit

[illegible]

EMISSIONS UNIT INFORMATIONSection [1] of [2]
Units 5A-5D**POLLUTANT DETAIL INFORMATION**Page [1] of [7]
Particulate Matter - Total**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: 17.6 lb/hour 54.6 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2000; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: See PSD Report, Section 2.0 and Appendix A.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: lb/hr based on oil firing all loads. TPY see PSD Report Section 2.0.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

POLLUTANT DETAIL INFORMATION

Page [1] of [7]
Particulate Matter - Total

**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: 17.6 lb/hr	4. Equivalent Allowable Emissions: 17.6 lb/hour 54.1 tons/year
5. Method of Compliance: Annual stack test: EPA Method 5 or 17; if > 400 hrs.	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions during oil firing - all loads: 500 hr/yr. TPY see PSD Report Section 2.0 and Appendix A.	

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: 14.4 lb/hr	4. Equivalent Allowable Emissions: 14.4 lb/hour 54.6 tons/year
5. Method of Compliance: VE Test < 10% opacity.	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions during gas firing – all loads: 8,760 hr/yr. See PSD Report Section 2.0 and Appendix A.	

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):	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

POLLUTANT DETAIL INFORMATION

Page [2] of [7]
Particulate Matter – PM₁₀

**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: 17.6 lb/hour 54.6 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2000; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: See PSD Report, Section 2.0 and Appendix A.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: lb/hr based on oil firing, 100% load. TPY see PSD Report Section 2.0.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

POLLUTANT DETAIL INFORMATION

Page [2] of [7]
Particulate Matter – PM₁₀

**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: 17.6 lb/hr	4. Equivalent Allowable Emissions: 17.6 lb/hour 54.6 tons/year
5. Method of Compliance: Annual stack test: EPA Method 5 or 17; if > 400 hrs.	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions during oil firing - all loads: 500 hr/yr. TPY see PSD Report Section 2.0 and Appendix A.	

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: 14.4 lb/hr	4. Equivalent Allowable Emissions: 14.4 lb/hour 54.6 tons/year
5. Method of Compliance: VE Test < 10% opacity.	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions during gas firing – all loads: 8,760 hr/yr. See PSD Report Section 2.0 and Appendix A.	

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):	

EMISSIONS UNIT INFORMATIONSection [1] of [2]
Units 5A-5D**POLLUTANT DETAIL INFORMATION**Page [3] of [7]
Sulfur Dioxide**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: 13.3 lb/hour 47.8 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference: GE, 2000; Golder, 2003.		7. Emissions Method Code: 2	
8. Calculation of Emissions: See PSD Report, Section 2.0 and Appendix A.			
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Emission factor: 2 grains S per 100 CF gas; 0.0015% S oil; lb/hr based on natural gas firing at 100% load. TPY see PSD Report Section 2.0 and Appendix A.			

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

POLLUTANT DETAIL INFORMATION

Page [3] of [7]
Sulfur DioxideF2. 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: 0.0015% Sulfur (S) oil	4. Equivalent Allowable Emissions: 3.1 lb/hour 47.8 tons/year
5. Method of Compliance: Fuel sampling.	
6. Allowable Emissions Comment (Description of Operating Method): Based on oil firing at 100% load: 35°F. TPY see PSD Report Section 2.0 and Appendix A.	

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: See Comment	4. Equivalent Allowable Emissions: 13.3 lb/hour 47.8 tons/year
5. Method of Compliance: Fuel sampling.	
6. Allowable Emissions Comment (Description of Operating Method): Requested allowable emissions and units: Pipeline Natural Gas. Natural gas firing CT with duct firing. TPY see PSD Report Section 2.0 and Appendix A.	

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):	

EMISSIONS UNIT INFORMATIONSection [1] of [2]
Units 5A-5D**POLLUTANT DETAIL INFORMATION**Page [4] of [7]
Nitrogen Oxides**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: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: 79.5 lb/hour 96.8 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2000; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: See PSD Report, Section 2.0 and Appendix A.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: lb/hr based on oil firing at 100% load; 35°F. TPY see PSD Report Section 2.0 and Appendix A.	

EMISSIONS UNIT INFORMATIONSection [1] of [2]
Units 5A-5D**POLLUTANT DETAIL INFORMATION**Page [4] of [7]
Nitrogen Oxides**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 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: SC – 42 ppmvd; CC – 10 ppmvd	4. Equivalent Allowable Emissions: 79.5 lb/hour 96.8 tons/year
5. Method of Compliance: CEM – 24-hr block average.	
6. Allowable Emissions Comment (Description of Operating Method): Requested allowable emissions and units at 15% O₂ - 100% load. Oil firing; maximum at 35°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.5 ppmvd	4. Equivalent Allowable Emissions: 24.2 lb/hour 96.8 tons/year
5. Method of Compliance: CEM – 24-hr block average.	
6. Allowable Emissions Comment (Description of Operating Method): Requested allowable emissions and units at 15% O₂ - 100% load. Gas firing; maximum at 35°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

Allowable Emissions Allowable Emissions 3 of 3

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: 105.1 lb/hour 169.5 tons/year
5. Method of Compliance: CEM – 24-hr block average.	
6. Allowable Emissions Comment (Description of Operating Method): Requested allowable emissions at 15% O₂ - 100% load; HPM firing. TPY see PSD Report Section 2.0 and Appendix A.	

EMISSIONS UNIT INFORMATIONSection [1] of [2]
Units 5A-5D**POLLUTANT DETAIL INFORMATION**Page [5] of [7]
Carbon Monoxide**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: 68.2 lb/hour 170.2 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2000; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: See PSD Report, Section 2.0 and Appendix A.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: lb/hr based on gas firing; 100% load/Duct firing with power augmentation. TPY see PSD Report Section 2.0.	

EMISSIONS UNIT INFORMATIONSection [1] of [2]
Units 5A-5D**POLLUTANT DETAIL INFORMATION**Page [5] of [7]
Carbon Monoxide**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 3

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: 68.1 lb/hour 170.2 tons/year
5. Method of Compliance: EPA Method 10; high load; if > 400 hours.	
6. Allowable Emissions Comment (Description of Operating Method): Oil firing; 35°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 9/17 ppmvd	4. Equivalent Allowable Emissions: 30.3/52.3 lb/hour 170.2 tons/year
5. Method of Compliance: EPA Method 10; high and low load.	
6. Allowable Emissions Comment (Description of Operating Method): 9 lb/hr – gas firing; 35°F; 100% load. 17 lb/hr – gas firing with duct burners; 95°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15/22.6 ppmvd	4. Equivalent Allowable Emissions: 46.2/68.2 lb/hour 170.2 tons/year
5. Method of Compliance: EPA Method 10; high load.	
6. Allowable Emissions Comment (Description of Operating Method): 15 ppmvd – HPM and power augmentation. 22.6 ppmvd – power augmentation with duct firing. TPY see PSD Report Section 2.0 and Appendix A.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

POLLUTANT DETAIL INFORMATION

Page [6] of [7]
Volatile Organic Compounds

**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: 7.62 lb/hour 14.3 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2000; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: See PSD Report, Section 2.0 and Appendix A. VOC emission exclusive of background VOC concentrations.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

POLLUTANT DETAIL INFORMATION

Page [6] of [7]
Volatile Organic Compounds

**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 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3.5 ppmvw	4. Equivalent Allowable Emissions: 7.62 lb/hour 14.3 tons/year
5. Method of Compliance: EPA Method 25A; high and low load.	
6. Allowable Emissions Comment (Description of Operating Method): Oil firing; maximum at 35°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.6 ppmvw; includes CT and duct burners	4. Equivalent Allowable Emissions: 4.56 lb/hour 14.3 tons/year
5. Method of Compliance: EPA Method 25A; high and low load.	
6. Allowable Emissions Comment (Description of Operating Method): Gas firing; 75°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 1.4 ppmvw	4. Equivalent Allowable Emissions: 2.69 lb/hour 14.3 tons/year
5. Method of Compliance: EPA Method 25A; high and low load.	
6. Allowable Emissions Comment (Description of Operating Method): HPM firing; 35°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

POLLUTANT DETAIL INFORMATION

Page [7] of [7]
Formaldehyde

**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: H095	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.472 lb/hour 1.71 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2000; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: See PSD Report, Section 2.0 and Appendix A. Formaldehyde emissions based on NESHAPS Subpart YYYY.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0.	

EMISSIONS UNIT INFORMATIONSection [1] of [2]
Units 5A-5D**POLLUTANT DETAIL INFORMATION**Page [7] of [7]
Formaldehyde**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: 91 ppbvd @ 15% O₂	4. Equivalent Allowable Emissions: 0.451 lb/hour 0.11 tons/year
5. Method of Compliance: EPA Method 320 of 40 CFR Part 63.	
6. Allowable Emissions Comment (Description of Operating Method): Oil firing; maximum at 35°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

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: 91 ppbvd @ 15% O₂	4. Equivalent Allowable Emissions: 0.404 lb/hour 1.7 tons/year
5. Method of Compliance: EPA Method 25A; high and low load.	
6. Allowable Emissions Comment (Description of Operating Method): Gas firing; 59°F; 100% load. TPY see PSD Report Section 2.0 and Appendix A.	

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):	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

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 2

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
4. Method of Compliance: EPA Method 9.	
5. Visible Emissions Comment: Excess emissions allowed pursuant to Rule 62-201.700(1) for 2 hours (120 mins) per 24 hr for startup, shutdown, and malfunction.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE10	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: EPA Method 9.	
5. Visible Emissions Comment: Proposed limit for gas and oil firing.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NO_x
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: not yet identified Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEM required pursuant to 40 CFR Part 75. NO_x monitoring includes diluent monitor (O₂ or CO₂).	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: not yet identified Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEM monitor anticipated pursuant to previous BACT determinations.	

EMISSIONS UNIT INFORMATION

Section [1] of [2]
Units 5A-5D

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: PSD Report ☐ 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: PSD Report ☐ 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: PSD Report ☐ 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 [1] of [2]

Units 5A-5D

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: <u>PSD Report</u> ☐ 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: <u>PSD Report</u> ☐ 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: _____ ☒ Not Applicable |
| 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 [1] of [2]

Units 5A-5D

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [2] of [2]
Cooling Tower

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

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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:
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3. Emissions Unit Identification Number:

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

9. Package Unit:
Manufacturer:

Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

This emission unit is a 22-cell mechanical draft cooling tower (see PSD Report).

EMISSIONS UNIT INFORMATION

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Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
Drift Eliminators

2. Control Device or Method Code(s):

EMISSIONS UNIT INFORMATION

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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:	million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	
	7 days/week 8,760 hours/year	
6. Operating Capacity/Schedule Comment:		

EMISSIONS UNIT INFORMATION

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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: See PSD Report		2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Exhausts through 22 stacks.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code: V	6. Stack Height: 65 feet	7. Exit Diameter: 38 feet	
8. Exit Temperature: 90°F	9. Actual Volumetric Flow Rate: 1,500,000 acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: 800,000 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: Volume is per cell.			

EMISSIONS UNIT INFORMATION

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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:		

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List of Pollutants Emitted by Emissions Unit

[illegible]

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Cooling Tower**POLLUTANT DETAIL INFORMATION**Page [1] of [2]
Particulate Matter - Total**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: 45.9 lb/hour 201.2 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: FPL, 2003; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: Maximum PM based on 30,000 TDS. See PSD Report, Section 2.0 and Appendix A.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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Particulate Matter - Total

**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: Design Drift Rate = 0.001%	4. Equivalent Allowable Emissions: 45.9 lb/hour 201.2 tons/year
5. Method of Compliance: none	
6. Allowable Emissions Comment (Description of Operating Method): See PSD Report, Section 2.0, and Appendix A.	

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):	

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Cooling Tower**POLLUTANT DETAIL INFORMATION**Page [2] of [2]
Particulate Matter – PM₁₀**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: 2.35 lb/hour 10.3 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: FPL, 2003; Golder, 2003.	7. Emissions Method Code: 2
8. Calculation of Emissions: PM₁₀ = 38.3% of PM at a TDS of 4,000; see PSD Report, Section 2.0 and Appendix A.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

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POLLUTANT DETAIL INFORMATION

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Particulate Matter – PM₁₀

**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: Design Drift Rate = 0.001%	4. Equivalent Allowable Emissions: 2.35 lb/hour 10.3 tons/year
5. Method of Compliance: none	
6. Allowable Emissions Comment (Description of Operating Method): See PSD Report, Section 2.0, and Appendix A.	

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):	

EMISSIONS UNIT INFORMATION

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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:	

EMISSIONS UNIT INFORMATION

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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:	

EMISSIONS UNIT INFORMATION

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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: PSD Report ☐ 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: PSD Report ☐ 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

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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: PSD Report ☐ 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: PSD Report ☐ 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: _____ ☐ Not Applicable
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

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Additional Requirements Comment

PSD REPORT

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1.0 INTRODUCTION

Florida Power & Light Company (FPL), proposes to license, construct, and operate a nominal 1,150-megawatt (MW) combined cycle unit, at the existing Turkey Point Plant located in unincorporated Miami-Dade County, Florida (Figure 1-1).

The Turkey Point Plant is an existing generating facility originally constructed in the mid to late 1960s, with the commercial in-service for Units 1 and 2 in 1967 and 1968, respectively. Unit 3 and Unit 4 were constructed in the early 1970s with commercial in-service in 1972 and 1973, respectively. The plant consists of the following units:

- Unit 1 – 400 MW (nominal capacity)
 - Steam electric generating unit firing residual oil and natural gas
- Unit 2 – 400 MW (nominal capacity)
 - Steam electric generating unit firing residual oil and natural gas
- Unit 3 - 700 MW (nominal capacity)
 - Nuclear electric generating unit
- Unit 4 - 700 MW (nominal capacity)
 - Nuclear electric generating unit
- Units FIC 1 through FIC5 – 2.5 MW (nominal capacity)
 - Black start diesel generating units associated with steam electric Units 1 and 2
- Units NIC1 through NIC4 – 2.5 MW (nominal capacity)
 - Emergency diesel generators associated with nuclear Units 3 and 4

The combined cycle unit (called Unit 5) will consist of four General Electric (GE) 7FA combustion turbines (CTs) and associated electric generators, four heat recovery steam generators (HRSGs) and single steam turbine with associated electric generator. This is referred to as a “4 on 1” combined cycle unit. Also included in the Project is a mechanical draft cooling tower. Together these facilities are referred to as the “Project”.

The CTs will use dry low-nitrogen oxide (DLN) combustion technology when operating on natural gas and water injection for nitrogen oxide (NO_x) control when operating on ultra low sulfur light oil (“light oil”). Each CT/HRSG will be installed with selective catalytic reduction (SCR) to further reduce emissions of NO_x. Each HRSG will be equipped with duct burners that will fire only natural

gas with a maximum heat input of 550 million British thermal units per hour (MMBtu/hr). The primary fuel for the CTs will be natural gas with distillate light oil used as backup fuel. Light oil will contain a maximum sulfur content of 0.0015 percent.

The permitting of the Project requires an Air Construction Permit and PSD review. PSD review requires air quality assessments for determining the facility's compliance with state and federal new source review (NSR) regulations, including addressing applicable PSD and nonattainment review requirements. The critical aspects of these assessments include the air quality impact analyses performed using appropriate air dispersion models and the Best Available Control Technology (BACT) analyses performed to evaluate the selected emission control technology.

The proposed Project will be a modification to an existing major air pollution source that will result in net increases in air emissions. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review for new or modified sources that increase air emissions above certain threshold amounts. Because the threshold amounts for a modification will be exceeded by the Project, the Project is subject to PSD review. EPA's PSD regulations are promulgated under 40 Code of Federal Regulations (CFR) Part 51.166. Florida's PSD regulations are codified in Rules 62-212.400, Florida Administrative Code (F.A.C.) and have been approved by EPA to FDEP. These Florida PSD regulations incorporate the requirements of EPA's PSD regulations.

Based on the emissions from the proposed facility, PSD review is required for each of the following regulated pollutants:

- Particulate matter (PM) as total suspended particulate matter (TSP),
- Particulate matter with aerodynamic diameter of 10 microns or less (PM₁₀),
- Nitrogen dioxide (NO₂),
- Sulfur dioxide (SO₂),
- Carbon monoxide (CO),
- Volatile organic compounds (VOCs), and
- Sulfuric acid mist.

Miami-Dade County has been designated as an attainment area for all criteria pollutants [i.e., attainment: (O₃), PM₁₀, SO₂, CO, and NO₂; unclassifiable: lead] and is a PSD Class II area for PM₁₀, SO₂, and NO₂; therefore, the PSD review will follow regulations pertaining to such designations.

The air permit application is divided into seven major sections:

- Section 2.0 presents a description of the Project, including air emissions and stack parameters.
- Section 3.0 provides a review of the PSD and nonattainment requirements applicable to the Project.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed facility with ambient air quality standards (AAQS), and PSD increments.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

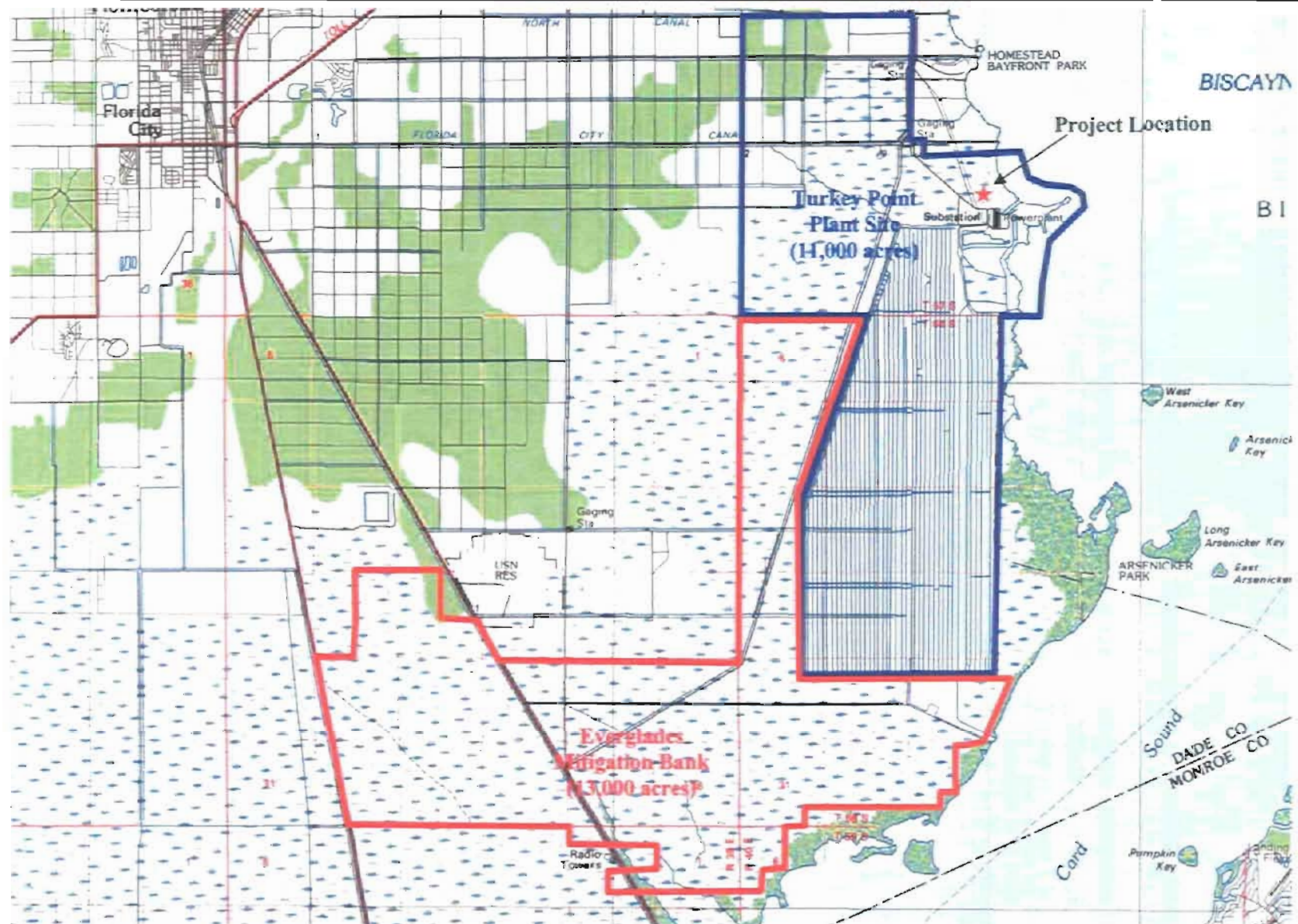


Figure 1-1.
FPL Turkey Point Plant Site Location, Project Location, and Everglades Mitigation Bank

Source: National Geographic, 2003; Golder, 2003.



2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

The Turkey Point Plant Site (shown in Figure 1-1) consists of 11,000 acres that is wholly owned by FPL. The Project will be located north of the existing Units 1 and 2 on the existing 11,000-acre Turkey Point Plant Site (exclusive of the 13,000-acre Everglades Mitigation Bank). The Project Area comprises of approximately 90 acres; within the Project Area, approximately 24 acres will be used for the power plant. There is minimal industrial, commercial, and residential development within a 5-kilometer (km) radius of the site. The plant elevation will be approximately 14 feet above sea level. The terrain surrounding the site is flat.

Natural gas is supplied to the existing Turkey Point Plant by the Florida Gas Transmission (FGT) natural gas pipeline. No onsite storage will be provided for natural gas. Light oil will be stored in a new 4.3-million-gallon tank.

2.2 POWER PLANT

The proposed facility will be configured as a 4-on-1 combined unit for base load service. The combined cycle unit will consist of four GE Frame 7FA CTs with an associated HRSGs and a steam turbine-generator. The CTs will use DLN combustion technology (when firing natural gas) and water injection (when firing distillate oil) to minimize NO_x formation. SCR will be installed in each HRSG to further reduce emissions of NO_x. Natural gas will be used as the primary fuel, and light distillate light oil will be used as an alternate fuel. Light oil usage will be limited to the equivalent of 500 hours per year (hr/yr) per CT at full load. Each HRSG will be equipped with duct burners with a maximum heat input of 550 MMBtu/hr. Duct firing will be limited to an equivalent heat input of 550 MMBtu/hr for 2,880 hours or 1,584,000 million Btu/year per CT/HRSG.

Plant performance for the GE 7FA CTs was developed for natural gas and oil at 50-, 75-, and 100-percent load and 35 degrees Fahrenheit (°F), 59°F, 75°F, and 95°F ambient dry bulb temperatures. Nominal part load percentages herein are relative to 100-percent load without evaporative cooling. Data were also developed for higher power modes (HPM) that include peak operation and power augmentation for the range of operating loads and temperatures. In addition, the CTs can operate with power augmentation (data are provided for ambient temperature of 80°F). More detailed discussions on these operations are presented in Section 2.3.

The CTs will be capable of operating from 50- to 100-percent base load. The efficiency of the CTs decreases at part load. As a result, the economic incentive is to dispatch the plant to keep the units operating as near to base load as possible.

Natural gas will be transported to the site via pipeline, and light oil will be trucked to the site. The distillate light oil, which will have a maximum sulfur content of 0.0015 percent, will be stored onsite in one aboveground storage tank, sized to hold approximately 108,000 barrels (4.3 million gallons).

Air emissions control will consist of using state-of-the-art DLN burners in the CTs when firing natural gas. Each GE Frame 7FA will be equipped with the GE DLN-2.6 combustion system that regulates the distribution of fuel delivery to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion system fuel nozzle is regulated to maintain unit load and minimize turbine emissions. The DLN-2.6 combustion system consists of six fuel nozzles per combustion can, with each operating as a fully premixed combustor. Of the six nozzles, five are located radially and one is in the center. The fuel system is fully automated and sequences the DLN-2.6 combustion system through a number of staging modes prior to reaching full load. The GE Frame 7FA has 14 combustors per turbine. Water injection will be used for NO_x control when firing distillate light oil. The SO₂ emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, VOC, and other pollutants (e.g., trace metals). These engineering and environmental designs maximize control of air emissions while minimizing economic, environmental, and energy impacts (see Section 4.0 for the BACT evaluation).

SCR reactors for Unit 5 will be located in the HRSG to provide the proper operating temperature range for the required reaction between ammonia and NO_x to achieve the proposed BACT emission rate and to assure the economical operation of the system. NO_x is reduced by a chemical reaction with the ammonia in the presence of the catalyst. The catalyst will be provided in modules, which will be installed into a structural steel reactor housing that is incorporated into the HRSG. Ammonia is carried by a diluent and injected into the exhaust gas upstream of the catalyst modules. The reactor housing will include an internal support structure for the catalyst modules, man-access and catalyst loading openings and instrument connections for monitoring catalyst performance. The ammonia handling system will include primary and standby diluent air blowers (each sized for 100-percent capacity), ammonia flow control and measurement devices, an ammonia/air mixing chamber,

distribution header(s), and an ammonia injection grid (AIG). Overall control of the system will be by the distributed control system (DCS).

Each CT will have evaporative cooling at the turbine air inlet that reduces the inlet air temperature and increases both the efficiency and power output at elevated ambient temperatures. This cooling system will only operate when the ambient temperature is 60°F or greater and the CTs are operating. This cooling system adds water vapor to the compressor inlet of the CTs, which increases the mass flow of air by evaporative cooling, but does not affect emission rate (i.e., ppmvd) of regulated pollutants. The CTs can operate without the evaporative coolers in service.

2.3 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated maximum hourly emissions and exhaust information representative of each CT/HRSG operating at base-load conditions (100-percent load), 75-percent load and 50-percent load conditions in combined cycle mode are presented in Tables 2-1 and 2-2 for natural gas and distillate oil firing, respectively. Table 2-1 also includes emissions and exhaust information for duct firing. The data are presented for ambient temperatures of 35°F, 59°F, 75°F, and 95°F. These temperatures represent the range of ambient temperatures that the CTs are most likely to experience. The performance data for the operating conditions are given in Appendix A.

The proposed pollutant gaseous emission concentrations and emission rates assumed for the Project are presented in Table 2-3.

The maximum short-term emission rates (lb/hr) generally occur at base load, 35°F operation, where the CT has the greatest output and greatest fuel consumption. The high-power mode (HPM) reflects either operating with power augmentation or operating in peak mode. Power augmentation is the use of steam when firing natural gas at loads above 95 percent to increase power output. About 1.5 lb steam per lb of fuel is used in this mode of operation. Peak mode is achieved by slightly increasing the exhaust temperature through the automated control system by adjusting the fuel distribution between the fuel nozzles while in pre-mix mode. The CTs are proposed to operate 400 hours per CT in peak mode or power augmentation mode.

Based on an ambient temperature of 59°F, the emission rates used to calculate maximum potential annual emissions for the CTs/HRSGs for regulated air pollutants are presented in Table 2-4 for the

facility. To produce the maximum annual emissions, it is assumed that each CT/HRSG would operate for 8,760 hours in combined cycle mode. Of the 8,760 combined cycle hours, 2,880 hours will be fired at 100-percent load with duct firing (550 MMBtu/hr). Because of the ultra low sulfur content (0.0015 percent) light oil, to produce the maximum annual SO₂ and sulfuric acid mist emissions, all 8,760 hours of operation will be on natural gas. The proposed limit on light oil is 3,838,000 MMBtu per year (1,919 MMBtu/hr x 4 CTs x 500 hours.) The potential emissions are based on the 59°F ambient air condition since it represents a conservative average when the annual average temperatures are slightly higher than 70°F.

Process flow diagrams of a CT/HRSG, operating at base load conditions with a compressor inlet temperature of 59°F, are presented in Figure 2-1.

The emissions for the optional cooling tower are presented in Table 2-5. A summary of the maximum total potential annual emissions estimated for the Project is given in Table 2-6.

Emission factors for hazardous air pollutants (HAPs) were evaluated based on the revised AP-42 emission factors and the EPA Combustion Turbine Emissions Database. The HAP emissions are based on emission factors from the April 2000 revision of EPA's AP-42 emission factors for large stationary combustion turbines. Summaries of the emission factors and emissions for light oil firing and gas firing are presented in Tables A-15 and A-16.

Except for formaldehyde and toluene, the emission factors are those presented in Tables 3.1-4 and 3.1-5 of the revised AP-42 section for combustion turbines. For formaldehyde, a review of EPA's database was conducted and an emission factor was estimated based on comparisons of the turbines and emission characteristics from EPA's database to those proposed for this project. A discussion regarding this review and estimation of the formaldehyde emission factor is presented in the following section.

The recent EPA emission factor suggests formaldehyde emissions from gas turbines of 710 lb/10¹² Btu when firing natural gas at loads greater than 80 percent and 280 lb/10¹² Btu when firing distillate oil. The EPA suggested emission factor for all loads is 3,100 lb/10¹² Btu. Since the proposed CTs will fire primarily natural gas, with limited oil firing, the worst-case annual emissions would be from natural gas firing.

The emission factors are not appropriate for the proposed CTs based on several factors. First, and most importantly, the data used to develop the AP-42 emission factors are not representative of the GE Frame 7FA combustion turbine. Second, a review of the data in the EPA database that relates to the characteristics clearly suggests a much lower emission factor for formaldehyde. Some of the important aspects of the EPA Gas Turbine Database related to formaldehyde emissions are as follows.

- The formaldehyde emissions are from small (< 30 MW) gas turbines. The available data are from an average capacity of about 28 MW. More importantly, the median capacity, or the turbine size where an equal number of turbines are above and below that size, is about 15 MW. Data from only 8 large turbines (>30 MW) are included in the EPA database, with a maximum size of 88 MW.
- In contrast to the AP-42 emission factors for formaldehyde, which are based on an average value, the median value is substantially lower. For all loads, the median formaldehyde emission factor is about 320 lb/10¹² Btu; for turbine loads greater than 50 percent, the median emission factor is about 110 lb/10¹² Btu. Since the median emission factor is about 8 to ten times lower than the average factor, this clearly points to the large range in formaldehyde emissions and how the individual turbine combustion characteristics can influence the results. The median is a measure of the middle of the distribution and in distributions where there is symmetry about the mean, and where the mean and median coincide. However, in highly skewed distributions, as that observed for formaldehyde emissions, the median is more representative of a “truer average” since the median is not influenced by extreme values.
- There is a strong relationship between formaldehyde and CO emissions, as noted by EPA in the support document and, and as observed in the data. Gas turbines with higher CO emissions had higher observed formaldehyde emissions. An evaluation of the coincident CO and formaldehyde data indicates that formaldehyde emissions were 150 lb/10¹² Btu when the CO emissions are less than 0.1 lb/MMBtu. The CO emission guarantees for the GE Frame 7FA is about 0.016 lb/MMBtu.

At present, there are limited test data of formaldehyde emissions from the GE Frame 7FA CTs.

Based on the available data, formaldehyde emissions would be within the range of 100 to 150 lb/10¹² Btu. EPA released the Federal Register notice for promulgating MACT standards for

combustion turbines in August 2003. The MACT standard is based on emissions of formaldehyde and limits emissions to 91 parts per billion (ppb) by volume (dry) corrected to 15-percent oxygen. This emission rate is equivalent to 218 and 235 lb/10¹² BTU natural gas and light oil firing, respectively (see Tables A-15a and A-16a). These emission rates were used to estimate emissions of formaldehyde.

An emission factor for toluene of 33 lb/10¹² Btu for natural gas firing was developed from the data in the EPA Combustion Turbine Emissions Database. This factor is based on the median value for loads greater than 80 percent. Similar to formaldehyde emission factors, there are no confirmed test data of toluene emissions from a GE Frame 7FA. The recent EPA emission factor, which is based on much smaller turbines than those proposed for this project, suggests toluene emissions from gas turbines of 130 lb/10¹² Btu when firing natural gas at loads greater than 80 percent. For all loads, the average and median EPA factors are 94 and 19 lb/10¹² Btu, respectively. Since the median emission factor is about 4 to 5 times lower than the average factor, this clearly points to the large range in toluene emissions and how the individual turbine combustion characteristics can influence the results. The emission factor of 33 lb/10¹² Btu is also about a factor of 4.5 times lower than that of formaldehyde, which is similar to the ratio of EPA's formaldehyde to toluene emission factors.

The emission factors for many of the other HAPs were developed by EPA in a manner similar to formaldehyde and toluene. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for these HAPs are considered to provide conservative estimates of emissions.

An evaluation of the HAP emissions from the Project indicates that emissions are less than 25 TPY for all HAPs and less than 10 TPY for any single HAP. As shown in Tables A-15 and A-16, the maximum total emissions of HAPs are estimated to 16.8 TPY with maximum emissions of any single HAPs at 7.6 TPY.

2.4 SITE LAYOUT, STRUCTURES, AND STACK SAMPLING FACILITIES

A plot plan of the proposed Project is presented in Figure 2-2 and a profile is presented in Figure 2-3. The dimensions of the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance to Rule 62-297.310(6) F.A.C.

2.5 EXCESS EMISSIONS

The start-up and shutdown and fuel in combined cycle operation will require an excess emission allowance greater than 2 hours allowed under the FDEP rules. This occurs during cold start-up where the operating load of the CTs is limited by the amount of steam that can be accepted by the steam turbine. This will result in excess emissions. The same excess emission allowance is requested for Turkey Point Unit 5 Project that was authorized for the Martin Expansion Project. Both Projects have similar steam turbines that receive steam during start-up (i.e., 400 MW). The proposed condition follows:

“As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A “documented malfunction” means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed 120 minutes in any 24-hour period except for the following specific cases.

- a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 6 hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within 12 hours. A cold “startup of the steam turbine system” is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Excess emissions resulting from documented malfunctions or shutdowns are not expressly limited by this subparagraph. Documented malfunctions and shutdowns are separately regulated according to the requirements stated in the first paragraph of Condition 16.}*
- b. For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 3 hours in any 24-hour period.
- c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed 4 hours in any 24-hour period. “Cold startup of a gas turbine/HRSG system” is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a 1-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.].”

Table 2-1. Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs and Duct Burners for Combined Cycle Operation-
Natural Gas Combustion

Parameter	Operating and Emission Data ^a for Ambient Temperature									
	Combustion Turbine/ HRSG					Combustion Turbine/ HRSG/ Duct Burner				
	w/Paug					w/Paug				
	35 °F	59 °F	75 °F	80 °F ^b	95 °F	35 °F	59 °F	75 °F	80 °F ^b	95 °F
<u>CT/HRSG Stack Data (ft)</u>										
Height	131	131	131	131	131	131	131	131	131	131
Diameter	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
<u>100 Percent Load</u>										
Temperature (°F)	203	202	204	204	201	189	188	189	188	190
Velocity (ft/sec)	61.6	59.0	57.3	57.9	54.5	61.0	58.4	56.7	54.1	54.3
Maximum Hourly Emissions per Unit										
SO ₂ lb/hr	10.2	9.8	9.4	9.5	8.9	13.3	12.8	12.4	12.5	11.9
PM/PM ₁₀ lb/hr	11.1	11.0	10.9	10.9	10.8	14.4	14.3	14.3	14.3	14.2
NO _x lb/hr	17.0	16.3	15.6	15.9	14.7	24.2	23.6	23.1	22.1	22.3
CO lb/hr	30.3	28.8	27.7	46.2	26.2	52.3	50.8	49.7	68.2	48.2
VOC (as methane) lb/hr	2.4	2.3	2.2	2.2	2.1	4.6	4.5	4.4	4.4	4.3
Sulfuric Acid Mist lb/hr	1.02	0.98	0.94	0.95	0.89	1.33	1.28	1.24	1.25	1.19
<u>75 Percent Load</u>										
Temperature (°F)	187	188	189	NA	190	NA	NA	NA	NA	NA
Velocity (ft/sec)	48.4	47.1	45.9	NA	44.3	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit										
SO ₂ lb/hr	8.3	7.9	7.7	NA	7.3	NA	NA	NA	NA	NA
PM/PM ₁₀ lb/hr	10.7	10.6	10.5	NA	10.5	NA	NA	NA	NA	NA
NO _x lb/hr	13.6	13.1	12.6	NA	12.0	NA	NA	NA	NA	NA
CO lb/hr	24.4	23.5	22.7	NA	21.7	NA	NA	NA	NA	NA
VOC (as methane) lb/hr	2.2	2.1	2.0	NA	1.9	NA	NA	NA	NA	NA
Sulfuric Acid Mist lb/hr	0.83	0.79	0.77	NA	0.73	NA	NA	NA	NA	NA
<u>50 Percent Load</u>										
Temperature (°F)	175	178	175	NA	182	NA	NA	NA	NA	NA
Velocity (ft/sec)	39.1	38.4	37.4	NA	36.9	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit										
SO ₂ lb/hr	6.6	6.4	6.2	NA	5.9	NA	NA	NA	NA	NA
PM/PM ₁₀ lb/hr	10.3	10.3	10.2	NA	10.2	NA	NA	NA	NA	NA
NO _x lb/hr	10.8	10.4	10.1	NA	9.6	NA	NA	NA	NA	NA
CO lb/hr	20.1	19.5	19.0	NA	18.3	NA	NA	NA	NA	NA
VOC (as methane) lb/hr	1.8	1.7	1.7	NA	1.6	NA	NA	NA	NA	NA
Sulfuric Acid Mist lb/hr	0.66	0.64	0.62	NA	0.59	NA	NA	NA	NA	NA

^a Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Duct firing is assumed for 100% operating load. No duct firing is assumed for loads less than 100%.

^b Steam augmentation and inlet fogging.

Source: Golder, 2003.

Table 2-2. Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs for Combined Cycle Operation-Distillate Light Oil Combustion

		Operating and Emission Data ^a for Ambient Temperature			
		Combustion Turbine/ HRSG			
Parameter		35 °F	59 °F	75 °F	95 °F
<u>CT/HRSG Stack Data (ft)</u>					
Height		131	131	131	131
Diameter		19.0	19.0	19.0	19.0
<u>100 Percent Load</u>					
Temperature (°F)		297	295	294	294
Velocity (ft/sec)		73.6	70.2	67.7	64.5
Maximum Hourly Emissions per Unit					
SO ₂	lb/hr	3.1	3.0	2.8	2.7
PM/PM ₁₀	lb/hr	17.6	17.6	17.6	17.5
NO _x	lb/hr	79.5	76.0	73.1	68.6
CO	lb/hr	68.1	64.7	62.1	58.9
VOC (as methane)	lb/hr	7.6	7.3	7.0	6.7
Lead	lb/hr	0.03	0.03	0.02	0.02
Sulfuric Acid Mist	lb/hr	0.62	0.59	0.57	0.53
<u>75 Percent Load</u>					
Temperature (°F)		271	274	276	278
Velocity (ft/sec)		55.6	54.3	53.3	51.4
Maximum Hourly Emissions per Unit					
SO ₂	lb/hr	2.5	2.4	2.3	2.2
PM/PM ₁₀	lb/hr	17.5	17.5	17.5	17.4
NO _x	lb/hr	62.5	60.1	58.2	55.0
CO	lb/hr	53.5	51.7	50.5	48.3
VOC (as methane)	lb/hr	6.0	5.8	5.7	5.5
Lead	lb/hr	0.02	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	0.49	0.47	0.46	0.43
<u>50 Percent Load</u>					
Temperature (°F)		256	259	264	268
Velocity (ft/sec)		44.6	44.0	43.5	42.6
Maximum Hourly Emissions per Unit					
SO ₂	lb/hr	1.9	1.9	1.8	1.7
PM/PM ₁₀	lb/hr	17.4	17.4	17.4	17.4
NO _x	lb/hr	49.0	47.4	45.9	43.6
CO	lb/hr	44.3	43.2	42.3	41.0
VOC (as methane)	lb/hr	4.9	4.8	4.7	4.6
Lead	lb/hr	0.02	0.02	0.02	0.01
Sulfuric Acid Mist	lb/hr	0.39	0.38	0.37	0.35

^a Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Table 2-3. Proposed Pollutant Gaseous Emission Concentrations and PM₁₀ Emission Rates For Each CT/HRSG Unit

Pollutant	Fuel	Method of Operation	Emission Rate	
			(ppmvd @15% O ₂)	lb/hour
Nitrogen Oxides	Gas	Combined Cycle (CC)	2.5	17.0
	Gas	CC - w/Duct Firing	2.5	24.2
	Gas	CC - w/Duct Firing, Power Aug.	2.5	22.1
	Oil	CC	10	79.5
Carbon Monoxide	Gas	CC	7.3	30.3
	Gas	CC - w/Duct Firing	10.2	50.8
	Gas	CC - w/Duct Firing, Power Aug.	14.7	68.2
	Oil	CC	20	68.1
Volatile Organic Compounds	Gas	CC	1.3	2.4
	Gas	CC - w/Duct Firing	2.6	4.4
	Gas	CC - w/Duct Firing, Power Aug.	2.5	4.4
	Oil	CC	2.8	7.3
Particulate Matter	Gas	CC	NA	11.1
	Gas	CC - w/Duct Firing	NA	14.4
	Gas	CC - w/Duct Firing, Power Aug.	NA	14.3
	Oil	CC	NA	17.6
Sulfur Dioxide	Gas	CC	NA	10.2
	Gas	CC - w/Duct Firing	NA	13.3
	Gas	CC - w/Duct Firing, Power Aug.	NA	12.5
	Oil	CC	NA	3.1
Sulfuric Acid Mist (SAM)	Gas	CC	NA	1.02
	Gas	CC - w/Duct Firing	NA	1.33
	Gas	CC - w/Duct Firing, Power Aug.	NA	1.25
	Oil	CC	NA	0.62

Source: GE CT Performance Data; Golder Associates, 2003

					Maximum Emissions (tons/year)					
					Operating Scenario	based on hours for				
Maximum Hourly Emissions (lb/hr) ^a					CC/ NG 100 % Load	8,760	5,880	5,480	5,380	5,380
					CC/ DB /NG100 % Load	0	2,880	2,880	2,880	2,480
					CC/ DB&PA/NG100 % Load	0	0	400	0	400
					CC/ OIL 100 % Load	0	0	0	500	500
Fuel:	NG	NG	NG	Oil						
Load:	100%	100% w/DB	100% w/DB & PA	100%						
Pollutant					TOTAL	8,760	8,760	8,760	8,760	8,760
<u>One Combustion Turbine</u>										
SO ₂	9.80	12.8	12.5	3.0	42.9	47.3	47.8	45.57	45.51	
PM/PM ₁₀	11.0	14.3	14.3	17.60	48.1	52.9	53.6	54.59	54.58	
NO _x	16.3	23.6	22.1	76.00	71.4	81.9	83.1	96.84	96.53	
CO	28.8	50.8	68.2	64.65	126.0	157.7	165.6	166.68	170.17	
VOC (as methane)	2.25	4.5	4.4	7.28	9.9	13.0	13.4	14.28	14.27	
Sulfuric Acid Mist	0.98	1.28	1.25	0.59	4.3	4.7	4.8	4.63	4.63	
HAPs	0.66	0.86	0.84	2.47	2.9	3.2	3.2	3.63	3.62	
Lead	0.00	0.00	0.00	0.025	0.0000	0.0000	0.0000	0.0063	0.0063	
<u>Four Combustion Turbines</u>										
SO ₂	39.2	51.3	50.2	12	172	189	191	182	182	
PM/PM ₁₀	43.9	57.4	57.1	70	192.4	211.7	214.4	218	218	
NO _x	65.2	94.5	88.3	304	285	328	332	387	386	
CO	115.1	203	273	259	504	631	662	667	681	
VOC (as methane)	9.00	17.8	17.5	29.1	39.4	52.1	53.8	57.1	57.1	
Sulfuric Acid Mist	3.92	5.13	5.02	2.4	17.2	18.9	19.1	18.5	18.5	
HAPs	2.63	3.45	3.37	9.89	11.53	12.70	12.85	14.5	14.5	
Lead	0.00	0.00	0.00	0.101	0.000	0.000	0.000	0.025	0.025	

^a Based on 59 °F ambient inlet air temperature except for power augmentation at 80 °F.

Table 2-5. Physical, Performance, and Emissions Data for the Mechanical Draft Cooling Tower

Parameter	Turkey Point 4 x 1
<u>Physical Data</u>	
Number of Cells	22
Deck Dimensions, ft	
Length	661.1
Width	114
Height	51
Stack Dimensions	
Height, ft	65
Stack Top Effective Inner Diameter, per cell, ft	38
Effective Diameter, all cells, ft	178.2
<u>Performance Data</u>	
Discharge Velocity, ft/min	1,323
Circulating Water Flow Rate (CWFR), gal/min	306,000
Design hot water temperature, °F	105.2
Design cold water temperature, °F	86.9
Heat Rejected, million Btu/hr	2,600
Design Air Flow Rate per cell, acfm	1,500,000
Liquid/ Gas (Air Flow) (L/G) Ratio	1.045
Hours of operation	8,760
<u>Emission Data</u>	
Drift Rate ^a (DR), percent	0.0010
Total Dissolved Solids (TDS) Concentration ^b , maximum ppm	30,000
Solution Drift ^c (SD), lb/hr	512.6
PM Drift ^d , lb/hr	45.9
tons/year	201.2
PM ₁₀ Drift ^e	
PM ₁₀ Emissions, lb/hr	2.35
tons/year	10.3

^a Drift rate is the percent of circulating water.

^b A TDS of 30,000 results in maximum PM emissions.

^c Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.34 lb/gal x 60 min/hr).

^d PM calculated based on total dissolved solids and solution drift (TDS x SD).

^e PM₁₀ based on Cooling Tower PM₁₀ emissions study see Appendix A.

Source: Marley, 2003. FPL, 2003, Golder, 2003.

Table 2-6. Summary of Maximum Potential Annual Emissions for the FPL Turkey Point Unit 5 Combined Cycle Project

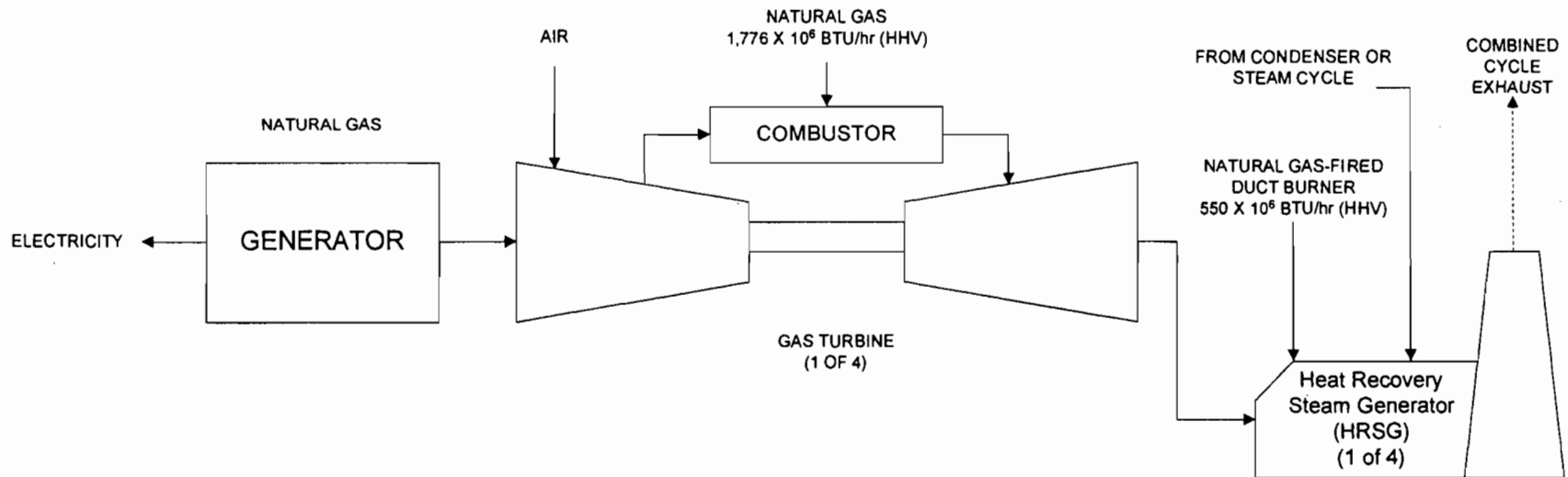
Pollutant	Annual Emissions (tons/year)			PSD Significant Emission Rate (tons/year)	PSD Review Required?
	4 CTs/HRSGs with Duct Burners	Cooling Tower	TOTAL		
SO ₂	191	NA	191	40	Yes
PM	218	201.2	419	25	Yes
PM ₁₀	218	10.3	218	15	Yes
NO _x	387	NA	387	40	Yes
CO	681	NA	681	100	Yes
VOC (as methane)	57.1	NA	57	40	Yes
Sulfuric Acid Mist	19.1	NA	19.1	7	Yes
Lead	0.025	NA	0.025	0.6	No

BASELOAD OPERATION
AMBIENT TEMPERATURE OF 59°F

COMBINED CYCLE

NATURAL GAS
 (with duct firing)
 993,802 ACFM
 58.4 ft/sec
 188°F

OIL
 1,193,859 ACFM
 70.2 ft/sec
 295°F



2-15

Figure 2-1. Process Flow Diagram
 Baseload Operation, Ambient Temperature of 59°F

Process Flow Legend

Solid/Liquid ———→
 Gas - - - - -→
 Steam ······→



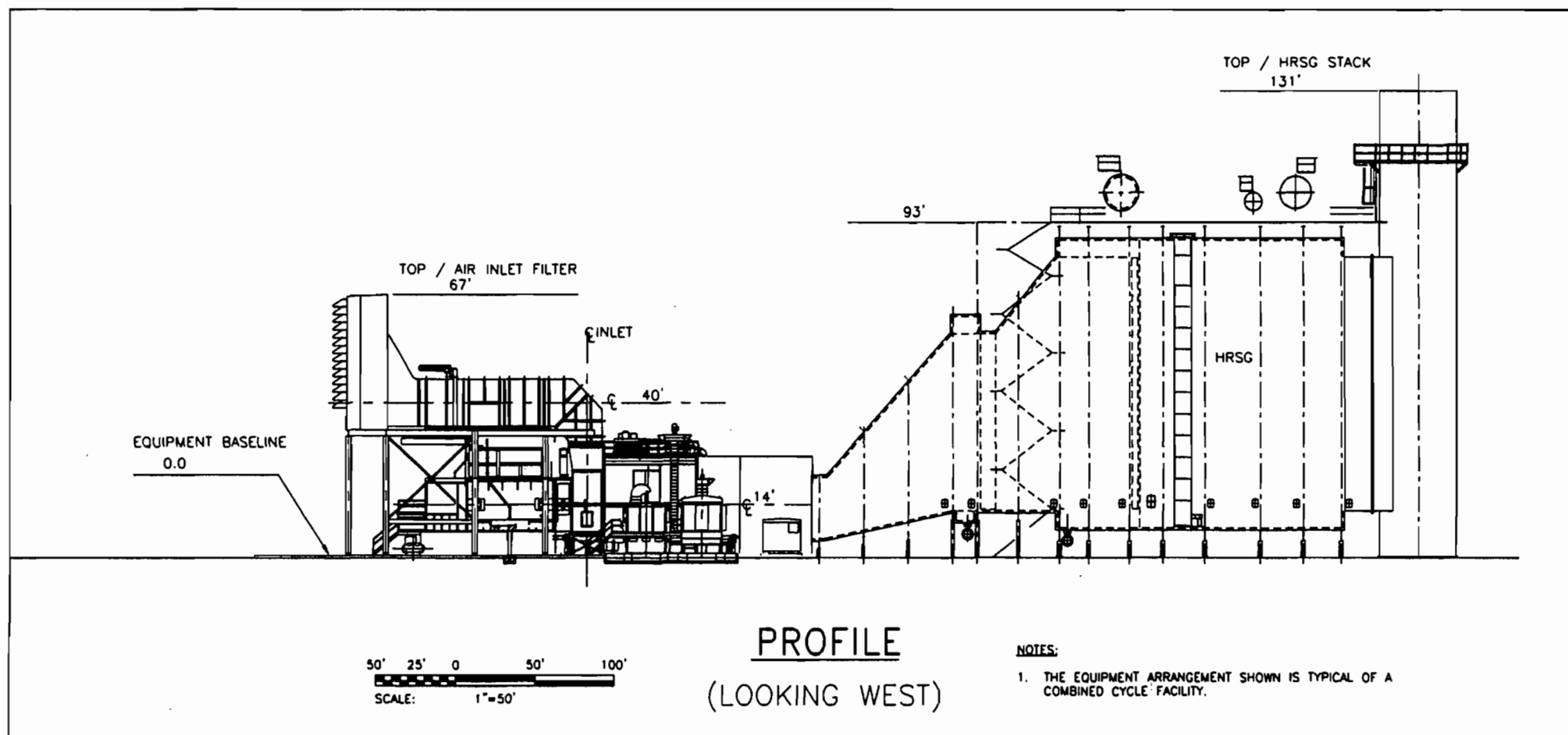


Figure 2-3. Profile of Combustion Turbine and Heat Recovery Steam Generator

Source: Black & Veatch, 2001; FPL, 2003; and Golder, 2003



3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal, state, and local air regulatory requirements and their applicability to the Project. These regulations must be satisfied before the proposed facility can begin operation.

3.1 NATIONAL, STATE, AND LOCAL AAQS

The existing applicable national, State of Florida, and local AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

Miami-Dade County has adopted AAQS for SO₂. These SO₂ standards are 25, 110, and 350 micrograms per cubic meter (µg/m³) for the annual, 24-hr, and 3-hr averaging times (Chapter 24, Section 24-17, Miami-Dade County Code).

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to FDEP.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

A "major modification" is defined under PSD regulations as a change at an existing major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO₂, PM₁₀, and NO₂ concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO₂, PM₁₀, and NO₂.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 51.166, *Prevention of Significant Deterioration of Air Quality*. The State of Florida's PSD regulations are found in Rule 62-212.400, F.A.C. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to GEP stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source (Rule 62-212.400, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Rule 62-210.200(38), F.A.C., as:

An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods,

systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with new source performance standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A

decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and the PSD Workshop Manual was used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decision making.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emission limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose for using it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility, for which the control technique was applied previously, must be justified. EPA has issued a draft guidance document on the top-down approach entitled *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990).

3.2.3 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models (Revised)*. The source impact analysis for criteria pollutants to address compliance with AAQS and PSD Class II increments may

be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is above significance levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas. The levels are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu\text{g}/\text{m}^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM_{10}	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

^a $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD reviews, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate to assist states in implementing the PSD permit process. The FDEP has accepted the use of these significant impact levels.

Various lengths of meteorological data records can be used for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO₂ and PM(TSP) concentrations or February 8, 1988, for NO₂ concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and, therefore, will affect PSD increment consumption.

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO₂ and PM(TSP) concentrations and after February 8, 1988, for NO₂ concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO₂ and PM(TSP) and February 8, 1988, in the case of NO₂.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO₂ and PM(TSP) and February 8, 1988, for NO₂.

The minor source baseline date for SO₂ and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Rules 62-204.200(22); 204.360, F.A.C.). The minor source baseline for NO₂

has been set as March 28, 1988 (Rule 62-204.200(22);204.360, F.A.C). It should be noted that references to PM(TSP) are also applicable to PM₁₀.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. Data for a minimum of 4 months are required. Existing data from the vicinity of the proposed source may be used, if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that a proposed major stationary facility or major modification is exempt from the monitoring requirements with respect to a particular pollutant, if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (Rule 62-212.400-3, F.A.C.). If a facility predicted impacts are less than the *de minimis* levels, therefore, preconstruction monitoring will not be required.

3.2.5 SOURCE INFORMATION/GEP STACK HEIGHT

Source information must be provided to adequately describe the proposed facility. The general type of information required for this facility is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant can not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical

regulations have been adopted by FDEP (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. A height established by applying the formula:

$$H_g = H + 1.5L$$

where: H_g = GEP stack height,

H = Height of the structure or nearby structure, and

L = Lesser dimension (height or projected width) of nearby structure(s); or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to 5 times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [Rule 62-212.400(5)(e), F.A.C.]. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

3.2.7 AIR QUALITY RELATED VALUES

An Air Quality Related Value (AQRV) analysis is required to assess the potential risk to AQRVs in PSD Class I areas. The Everglades National Park is the closest Class I area to the Turkey Point Plant Site, and is located about 21 km west of the Project Site.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.

Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) must also be evaluated.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities, located in a nonattainment area, must undergo nonattainment review. A new major facility is required to undergo this review, if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review, if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Rule 62-2.500(2)(c)2.a., F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of NSR for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence

are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The proposed Project will be subject to one or more NSPS. The CTs will be subject to 40 CFR Part 60, Subpart GG, and the duct burners will be subject to 40 CFR Part 60, Subpart Da. On October 15, 2003, EPA promulgated changes to 40 CFR Part 60, Subpart Kb, that would exempt light oil tanks containing No. 2 distillate oil by virtue of its vapor pressure (FR Vol. 68, No. 199, Pages 59328-59333).

Combustion Turbine

The CTs will be subject to emission limitations covered under Subpart GG, which limits NO_x and SO₂ emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired.

NO_x emissions are limited to 75 ppmvd corrected to 15-percent O₂ and heat rate, while SO₂ emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, there are requirements for notifying, record keeping, reporting, performance testing, and monitoring.

These are summarized below:

40 CFR 60.7 Notification and Record Keeping

- (a)(1) Notification of the date of construction - 30 days after such date.
- (a)(3) Notification of actual date of initial start-up - within 15 days after such date.
- (a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date.

60.7 (b) Maintain records of all start-ups, shutdowns, and malfunctions.

- (c) Excess emissions reports – semi-annually by the 30th day following six-month period.
(required even if no excess emissions occur)
- (d) Maintain file of all measurements for 2 years.

60.8 Performance Tests

- (a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.
- (d) Notification of Performance tests at least 30 days prior to them occurring.

40 CFR Subpart GG

60.334 Monitoring of Operations

- (a) continuous monitoring system required for water-to-fuel ratio to meet NSPS; system must be accurate within ± 5 percent.
- (b) Monitor sulfur and nitrogen content of fuel.
 - Oil - (1): each occasion that fuel is transferred to bulk storage tank.
 - No intermediate storage – (2): daily monitoring required.

Duct Burner

The applicable NSPS is 40 CFR Part 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. This subpart applies to electric utility combined cycle combustion turbines that are capable of combusting more than 250-MMBtu/hr heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam-generating unit are subject to this regulation.

The applicable NO_x and PM NSPS limits are 1.6 lb/MW (gross) and 0.03 lb/MMBtu, respectively, for the gas-fired duct burners being considered for the Project. The proposed NO_x and PM emission limits of 0.08 lb/MW and 0.008 lb/MMBtu, respectively, for the Project will be much lower than the NSPS.

3.4.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

EPA released a signed final rule promulgating the MACT standard for combustion turbines. The MACT standard is based on emissions of formaldehyde and limits emissions to 91 parts per billion (ppb) by volume (dry) corrected to 15-percent oxygen which is equivalent to 218 lb/10¹² Btu when firing natural gas and 235 lb/10¹² Btu when firing light oil. The final rule has not yet been published

in the Federal Register, but could potentially apply to the project. Based on discussion with the Gas Turbine Association, the manufacturers group for gas turbines, the EPA intends to grant a petition to de-list combustion turbines that use DLN combustion and limit oil firing to less than 1,000 hrs cumulative for the new CTs. If the delisting petition is granted as expected, the CT MACT would not apply to the project unless it exceeds 1,000 hrs on oil. Regardless, based on available data, it appears that the proposed Unit 5 could meet the MACT limits if required.

3.4.3 FLORIDA RULES

The FDEP regulations for new stationary sources are covered in the F.A.C. The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(7): subsection (b)39 for stationary gas turbines Substation (6)(2) for the duct burners, and subsection (b)16 for volatile organic liquid storage vessels. Therefore, the facility is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

3.4.4 FLORIDA AIR PERMITTING REQUIREMENTS

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400 F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.5 LOCAL AIR REGULATIONS

Miami-Dade County has adopted emission limits for opacity, PM and SO₂. The opacity limit is 20 percent (Section 24-14, Miami-Dade County Code) and similar to that adopted by FDEP and applicable to existing fossil fuel fired steam generators with a heat input of 250 MMBtu/hr and greater [Rule 62-296.405(1) F.A.C.]. The PM emission limits are based on a process weight table that limits the PM emissions based on the process weight. Process weight is the total amount of all materials introduced into a process unit [Section 24-16 (1)]. It does not include uncombined water, liquid and gaseous fuels, combustion and other air introduced into the process. These PM limits would not apply to the existing Turkey Point Units 1 and 2. The SO₂ emission standards set

limitations for stationary combustion sources. For existing sources greater than 250 MMBtu/hr heat input and firing liquid fuel the limitation is 1.1 lb/MMBtu [Section 24-17 (2)(a)(ii)], the same as that established by FDEP in the Title V Operating Permit and applicable to Units 1 and 2.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The facility site is located in Miami-Dade County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Miami-Dade County and surrounding counties are designated as PSD Class II areas for SO₂, PM(TSP), and NO₂. The nearest Class I area is the Everglades National Park (NP) located about 21 km (13 miles) to the south-southwest of the facility site.

3.5.2 PSD REVIEW

Pollutant Applicability

The Turkey Point Plant is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 100 TPY and the emissions units are one of the 28 listed categories. The addition of the Project at the Turkey Point Plant is a modification under the PSD rules and PSD review is required for any pollutant for which the emissions exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed Project will trigger PSD for PM(TSP), PM₁₀, SO₂, NO_x, CO, VOC and sulfuric acid mist. Impacts for these pollutants that are predicted to be above the significant impact levels require a modeling analysis incorporating the impacts from other sources is required. (Note: EPA no longer requires PSD review for HAPs from PSD review. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

As part of the PSD review, a PSD Class I increment analysis is required if the proposed facility's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I area to the plant site is about 21 km from the site and a PSD Class I increment analysis and an evaluation of impacts to AQRVs is required.

Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG. The proposed emissions for the turbines will be well below the specified limits (see Section 4.0).

The applicable NSPS for the duct burners is 40 CFR Part 60, Subpart Da. The proposed emissions for the duct burners will be well below the specified limits (see Section 4.0).

The NESHAPs Subpart YYYY may potentially apply to the project. Information available from the EPA indicate that the Project can meet the proposed MACT of 91 ppbvd corrected to 15-percent oxygen for formaldehyde.

Ambient Monitoring

Based on the estimated pollutant emissions from the proposed plant (see Table 3-4), a pre-construction ambient monitoring analysis is required for PM₁₀, SO₂, NO₂, CO, and O₃ (based on VOC emissions). If the net increase in impact of other pollutants is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the pre-construction ambient monitoring requirement is available by Rule 62-212.400(3)(e) F.A.C. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

As shown in Table 3-4, the proposed plant's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels for all pollutants. Therefore, pre-construction monitoring is not required to be submitted for this facility. The emissions of VOC are above the *de minimis* monitoring threshold. The monitoring analysis is presented in Section 5.0.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 feet (ft)] high. The stacks for the Project will be 131 ft. These stack heights do not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CT emissions caused by nearby structures are included in the modeling analysis.

3.5.3 NONATTAINMENT REVIEW

The facility site is located in Miami-Dade County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

3.5.4 OTHER CLEAN AIR ACT REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations would be applicable to the proposed facility for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire).

The permit would require the units to hold SO₂ emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO₂ emissions. Allowances can be sold, purchased, or traded.

Continuous emission monitoring (CEM) for SO₂ and NO_x is required for gas fired and oil fired affected units. When an SO₂ CEM is selected to monitor SO₂ mass emissions, a flow monitor is also required. Alternately, SO₂ emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO₂ emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

Pollutant	Averaging Time	AAQS ($\mu\text{g}/\text{m}^3$)			PSD Increments ($\mu\text{g}/\text{m}^3$)		Significant Impact Levels ($\mu\text{g}/\text{m}^3$) ^b
		Primary Standard	Secondary Standard	Florida	Class I	Class II	
Particulate Matter ^c (PM ₁₀)	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone ^c	8-Hour Maximum ^d	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM₁₀) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

NA = Not applicable, i.e., no standard exists.

^a Short-term maximum concentrations are not to be exceeded more than once per year.

^b Maximum concentrations are not to be exceeded.

^c On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, PM_{2.5} standards were introduced with a 24-hour standard of 65 $\mu\text{g}/\text{m}^3$ (3-year average of 98th percentile) and an annual standard of 15 $\mu\text{g}/\text{m}^3$ (3-year average at community monitors). These standards are not yet applicable and have been challenged at the federal level.

^d 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less. The standard is not yet applicable and has been challenged at the federal level.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-204, F.A.C.

Table 3-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	<i>De Minimis</i> Monitoring Concentration ^a (µg/m ³)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM ₁₀)	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY ^b
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.

NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.

NSPS = New Source Performance Standards.

NESHAP = National Emission Standards for Hazardous Air Pollutants.

g/m³ = micrograms per cubic meter.

^a Short-term concentrations are not to be exceeded.

^b No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Sources: 40 CFR 52.21; Rule 62-212.400.

Table 3-3. Maximum Emissions Due to the Proposed Project Compared to the PSD Significant Emission Rates

Pollutant	Pollutant Emissions (TPY)		PSD Review
	Potential Emissions from Proposed Project ^a	Significant Emission Rate	
Sulfur Dioxide	191	40	Yes
Particulate Matter [PM(TSP)]	419	25	Yes
Particulate Matter (PM ₁₀)	218	15	Yes
Nitrogen Dioxide	387	40	Yes
Carbon Monoxide	681	100	Yes
Volatile Organic Compounds	57	40	Yes
Lead	0.025	0.6	No
Sulfuric Acid Mist	19.1	7	Yes
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	2.3x10 ⁻³	0.1	No

Note: NEG = Negligible.

^a A. Based on emissions from operating at base load at 59°F for all pollutants except SO₂:

- 100-percent load, natural gas – 4,880 hours
- 100-percent load with duct burners, natural gas – 2,880 hours
- 100-percent load, oil firing – 500 hours

B. SO₂ emissions based on operations at baseload at 59°F:

- 100-percent load, natural gas – 5,880 hours
- 100-percent load with duct burners, natural gas – 2,880 hours

Includes cooling tower (see Table 2-5).

Table 3-4. Predicted Net Increase in Impacts Due to the Proposed Project Compared to PSD
De Minimis Monitoring Concentrations

Pollutant	Concentration (µg/m³) Predicted Increase in Impacts ^a		<i>De Minimis</i> Monitoring Concentration
	Natural Gas	Light Oil	
Sulfur Dioxide	2.23	0.34	13, 24-hour
Particulate Matter (PM ₁₀)	3.15	3.70	10, 24-hour
Nitrogen Dioxide	0.25	0.26 ^b	14, annual
Carbon Monoxide	29.6	18.9	575, 8-hour
Volatile Organic Compounds	57 TPY		100 TPY

^a See Section 6.0 for air dispersion modeling results.

^b Based on combined cycle with natural gas firing for 8,260 hours and light oil firing for 500 hours.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, SO₂, CO, PM/PM₁₀, and sulfuric acid mist (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed "F" Class CTs are summarized in Table 2-6.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies. The analysis must, by definition, be specific to the Project (i.e., case by case).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_x is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15-percent O₂. For the CTs being considered for the Project, the NSPS emission limit for NO_x, with the NSPS heat rate correction, is over 100 parts per million (ppm) firing natural gas and distillate oil (corrected to 15-percent O₂ at a fuel-bound nitrogen content of 0.015 percent). The proposed NO_x emission limits for the Project in combined cycle mode will be 40 times lower than the NSPS when firing natural gas and 8 times lower than the NSPS when firing distillate oil.

The applicable NSPS for the duct burner are codified in 40 CFR 60, Subpart Da and is also summarized in Attachment B. The applicable NO_x emission limit is 1.6 lb/MW-hr. The combined CT and duct burner emissions rate with SCR of 2.5 ppmvd corrected to 15-percent O₂ is equivalent to about 0.08 lb/MW-hr or over 10 times lower than the applicable NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 OVERVIEW OF PROPOSED BACT

In recent permitting actions, BACT for heavy-duty industrial gas turbines has been determined. These decisions established emission rates that were achieved through the use of advanced DLN combustors and SCR for limiting emissions of NO_x, good combustion practices for minimizing CO and VOC emissions, and the use of clean fuels (natural gas) for control of other emissions, including PM₁₀ and SO₂. The BACT proposed for the Project is consistent with these permits. The results of the BACT analysis have concluded the following controls as BACT for the Project.

1. The Project will use state-of-the-art DLN combustion technology and SCR to achieve gas turbine exhaust NO_x levels of no greater than 2.5 ppmvd corrected to 15-percent O₂ when firing natural gas and 10 ppmvd corrected to 15-percent O₂ when firing oil.
2. CO emissions when firing natural gas will be limited to 9 ppmvd at baseload to 50-percent load, 17 ppmvd with duct firing, and 22.6 ppmvd with HPM and duct firing. When firing distillate oil, CO will be limited to 20 ppmvd.
3. Emission rates of PM₁₀ and SO₂ will be limited using natural gas and light oil.

A summary of the emission rates proposed as BACT is presented in Table 4-1. Excess emissions proposed for the Project is addressed in Section 2.5.

4.3.2 NITROGEN OXIDES

Technology Description

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for NO_x emissions. An evaluation of the available and feasible control technologies determined that combustion along with SCR could provide the maximum degree of emission reduction. SCONOXTM is commercially available but has not been demonstrated on "F" Class combustion turbines. Other available technologies such as NO_xOut, Thermal DeNO_x, NSCR, and XONONTM Combustion System were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project. Appendix B presents a discussion of these NO_x control technologies and their feasibility for the Project.

DLN combustor technology has been offered and installed by manufacturers to reduce NO_x emissions by inhibiting thermal NO_x formation through premixing fuel and air prior to combustion

and providing staged combustion to reduce flame temperatures. NO_x emissions from 25 ppmvd (corrected to 15-percent O_2) and less has been offered by manufacturers for advanced CTs. This technology prevents pollution since NO_x emissions are inhibited from forming. When firing distillate oil, NO_x is limited using water injection to 42 ppmvd (corrected to 15-percent O_2).

SCR is a post-combustion process where NO_x in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. It is available from vendors for combined cycle applications. The reaction occurs typically between 600°F and 750°F, which occur in combined cycle units in the HRSG. SCR has been installed and operated on combined cycle facilities using catalysts with temperature ranges from 600 to 750°F and generally achieving 9 ppmvd (corrected to 15-percent O_2) or less while burning natural gas.

Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic and special precautions in materials and ammonia injection rates must be implemented to minimize their formation.

Ammonia injected in the SCR system, which does not react with NO_x , is emitted directly and referred to as ammonia slip. In general, SCR manufacturers guarantee an ammonia slip to be no more than 9 ppmvd corrected to 15-percent oxygen (O_2). SCR is technically feasible for the Project.

Although $\text{SCONO}_x^{\text{TM}}$ is available, it has not been demonstrated on a "F" Class combustion turbine. The $\text{SCONO}_x^{\text{TM}}$ system has only been operated on a 32-MW facility in California since 1996 and a 5-MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The $\text{SCONO}_x^{\text{TM}}$ technology installed on an "F" Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to 30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that O_2 is not introduced and regeneration gas (hydrogen) is introduced. Seal leaks could be significant as applied to the large volume flows associated with a "F" Class turbine. Although the amount of sulfur in natural gas is very low, the $\text{SCONO}_x^{\text{TM}}$ catalyst is poisoned with sulfur compounds requiring the installation of the $\text{SCOSO}_x^{\text{TM}}$ to further remove sulfur compounds as part of the overall system. The ability of $\text{SCOSO}_x^{\text{TM}}$ to further remove sulfur compounds as part of the overall $\text{SCONO}_x^{\text{TM}}$ system has not been demonstrated when firing distillate oil.

Over the last several years, the permitting trend for advanced CTs, even in combined cycle configuration, is the use of DLN combustors with SCR. In Region IV, the predominate emission rate established as BACT has been 3.5 ppmvd corrected to 15-percent O₂ when firing natural gas. Several projects in Florida have established case-by-case BACT of 3.5 and 2.5 ppmvd corrected to 15-percent O₂ when firing natural gas using DLN and SCR.

The proposed CTs will be fired with natural gas and distillate oil. The BACT evaluation was based on DLN combustors in combination with SCR and SCONO_xTM. The BACT evaluation considered both 3.5 and 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas.

The following sections present a summary of the economic, environmental, and energy impacts of the available, technically feasible and demonstrated control technology alternatives for the combined cycle units. Appendix B contains the detailed information on the costs, environmental, and energy impacts.

Impacts Analysis – 3.5 ppmvd Corrected to 15 Percent O₂

Economic--The total estimated capital costs of SCR on a CT/HRSG are \$2,315,000. The total annualized cost of applying SCR with DLN combustion is \$990,200. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the DLN combustors is estimated at \$3,744 per ton of NO_x removed.

The capital and annualized costs for SCONO_xTM are based on a budgetary cost estimate provided by ABB Alstom Environmental Systems. The budgetary estimate of capital costs for SCONO_xTM on one turbine/HRSG unit for one combined cycle unit is \$26.6 million. In contrast, the capital costs for SCR is about \$2.3 million, which clearly is about 10 times less costly than SCONO_xTM of SCR. The annualized cost of SCONO_xTM is estimated at \$5.1 million. The cost effectiveness of SCONO_xTM is \$19,300 per ton of NO_x. In contrast, the cost effectiveness of SCR is about \$3,744 per ton of NO_x removed. SCONO_xTM is more than 5 times less cost effective than SCR with uncertainty in its demonstrated feasibility. It should be noted that the annualized costs for SCONO_xTM did not include provisions for required mechanical maintenance activities.

Environmental--The maximum predicted NO_x impact of the Project is considerably below the NO₂ PSD Class II increment of 25 µg/m³ (annual average) and the AAQS of 100 µg/m³ (annual average).

The maximum annual impact for the Project is about $0.26 \mu\text{g}/\text{m}^3$ when firing natural gas, which is less than 1 percent of the AAQS. The addition of SCR will reduce NO_x emissions by about 265 TPY per CT/HRSG (about 66-percent reduction) from the combined cycle operation beyond those achieved through the use of DLN combustors.

The use of DLN combustor technology is "pollution prevention". The use of SCR has associated primary and secondary environmental impacts. Emissions of ammonia and ammonium salts (such as ammonium sulfate and bisulfate) will occur. Ammonia emissions with the use of SCR are a result of unreacted ammonia that may be emitted. Vendors typically provide ammonia slip guarantees of 9 ppmvd corrected to 15-percent O_2 . Maximum ammonia emissions are 111 TPY at the guarantee ammonia slip level. However, this level of ammonia slip occurs only as the catalyst ages. Initial ammonia slip levels are less than 5 ppmvd. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and up to 9.6 TPY could be emitted.

The electrical energy required to run the SCR system and the backpressure from the turbine will reduce the available power from the Project. The backpressure is a result of the catalyst modules located in the exhaust gas stream in the HRSG. With use of DLN combustors at an emission level of 9 ppmvd (corrected to 15-percent O_2), the backpressure to reduce NO_x to 3.5 ppmvd (corrected to 15-percent O_2) is about 2.5 inches of water gauge. This backpressure reduces the power generated by the combustion turbine. This lost power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. The net reduction in emissions with SCR (i.e., reduction in NO_x minus ammonia and secondary emissions), when all criteria pollutants are considered, will be about 137 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted.

SCR will require the construction and maintenance of storage vessels for aqueous ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119. The Project proposes using aqueous ammonia for the SCR system.

While ammonia is not used or emitted from a SCONO_xTM system, there are substantial natural gas, steam, and back pressure for the SCONO_xTM system that would directly result in environmental impacts. SCONO_xTM requires about 17,795 lb/hr of steam and 80 lb/hr of natural gas. In addition, the backpressure of the SCONO_xTM system is 200 percent over that of the SCR. This increased energy use would create additional criteria pollutants of about 41 TPY per unit and about 22,900 TPY per unit of additional carbon dioxide emissions compared to the Project using SCR (i.e., about 3,400 TPY per unit).

Energy--Energy penalties occur with SCR. With SCR, the output of the CT can be reduced over that of advanced low-NO_x combustors due to the backpressure on the CT. In combined cycle configuration and with a low base emission level (i.e., 9 ppmvd corrected to 15-percent O₂) and 66 percent NO_x reduction, the output reduction is estimated to be about 0.3 percent. This penalty is the result of the SCR pressure drop, which would be about 2.5 inches of water and would amount to about 4,532,000 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 700,800 kWh per year. Taken together, the total lost generation and energy requirements of SCR of 4,689,967 kWh per year could supply the electrical needs of about 436 residential customers. To replace this lost energy, an additional 5.3×10^{10} British thermal units per year (Btu/yr) or about 54 million cubic feet per year (ft³/yr) of natural gas would be required.

SCONO_xTM, in contrast to SCR, is very energy intensive. The SCONO_xTM system has about 2 times more backpressure on the turbine requires steam and natural gas for the regeneration process. The natural gas needed to generate the steam for the SCONO_xTM system is equivalent to 26.3 MMBtu/hr/unit or 230,000 MMBtu per year per unit. The overall energy usage is equivalent to about 35,109,000 kW per hour per year or equivalent energy for about 2,926 residential customers. The energy equivalence in terms of natural gas usage is 362 million ft³/yr or about 7 times that of SCR. When all the energy requirements for SCONO_xTM are considered, it is about 2.32 percent of the combustion turbine heat input. In contrast, SCR results in an additional 0.35 percent of the combustion turbine heat input.

Technology Comparison--The proposed Project will use an advanced heavy-duty industrial gas turbine with advanced DLN combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is DLN combustors that prevent the formation of air pollutants within the combustion process, thereby

minimizing the amount of add-on controls that can have an impact on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the proposed "F" class advanced machine is about 170 MW compared to the 70 to 120 MW conventional machines. The higher initial firing temperature (i.e., 2,600°F) results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines. This has the added advantage of producing less air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustor design.

The second unique attribute of the advanced machine is the use of DLN combustors that will reduce NO_x emissions to 9 ppmvd when firing natural gas. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air is premixed prior to ignition. This level of control will result in NO_x emissions of about 0.04 lb/10⁶ Btu for gas firing, which are less than half of the emissions generated from conventional fossil fuel-fired steam generators.

The use of SCR on combined cycle projects has been a recent trend in Florida and Region IV. Its use can limit NO_x emissions, while retaining much of the benefits of the advanced CT technology in combined cycle configuration.

From a technology standpoint, SCR has been demonstrated as feasible on over 100 combined cycle projects. In contrast, SCONO_xTM has only been operating over a few years on small turbines that are over 10 times smaller than the "F" Class turbine being proposed for the Project. As noted from the information in Appendix B, the SCONO_xTM system requires a considerable amount of mechanical equipment that must be operated in a high volume flow field. SCR has no moving parts to complicate operation. Over time, there is considerable uncertainty in the maintenance and replacement requirements of the mechanical components of the SCONO_xTM system on a large turbine.

Economic Impact Analysis – 2.5 ppmvd Corrected to 15 Percent O₂-- Appendix B contains cost evaluation for a NO_x emission rate of 2.5 ppmvd corrected to 15-percent O₂ when firing natural gas. The NO_x emission rate when firing distillate oil is 10 ppmvd corrected to 15-percent O₂. The cost for SCR were adjusted based on vendor estimates. For SCONO_xTM, the capital cost was kept the same and only the catalyst changeout cost were increased.

The results of the evaluation for total cost effectiveness are presented below:

	SCR @ 3.5 ppmvd	SCONO _x TM @ 3.5 ppmvd
Total Annualized Costs	\$990,181	\$5,095,698
Cost Effectiveness	\$3,744	\$19,265
	SCR @ 2.5 ppmvd	SCONO _x TM @ 2.5 ppmvd
Total Annualized Costs	\$1,125,622	\$5,176,062
Cost Effectiveness	\$3,753	\$17,259

Note: Total tons removed at 3.5 ppmvd is 264.5 TPY and at 2.5 ppmvd is 299.9 TPY.

It should be emphasized that SCONO_xTM is not considered a demonstrated technology for "F" Class combustion turbines and has not been used or proposed when firing distillate oil. Moreover, the operational experience is non existent on "F" Class turbines. Indeed, the cost effectiveness did not consider any additional operational cost of this technology as a result of the extensive mechanical equipment required. Moreover, SCONO_xTM has considerable collateral environmental and energy impacts as noted in the application.

The incremental cost using SCR from an emissions rate of 3.5 ppmvd corrected to 15-percent O₂ to 2.5 ppmvd corrected to 15-percent O₂ is shown below:

Incremental Cost Effectiveness (3.5 to 2.5 ppmvd)

\$1,125,622 Annualized cost for SCR at 2.5 ppmvd
\$990,181 Annualized cost for SCR at 3.5 ppmvd
\$135,441 Difference
97.9 TPY emissions at 2.5 ppmvd
133.4 TPY emissions at 3.5 ppmvd
35.5 TPY reduced
\$3,815 Incremental Cost Effectiveness

Technical Feasibility--There are also significant issues in demonstration compliance with an emission limit as low as 2.5 ppmvd corrected to 15-percent O₂. Such problems will occur with an emission rate of 3.5 ppmvd but be exacerbated with even a lower limit. The difficulties include the reliability of the continuous emission monitoring measurement, availability and stability of calibration gases, precision and accuracy of reference measurements (e.g., EPA Method 7E) and increased ammonia slip. Moreover, there is a general lack of experience in demonstrating compliance over the long term. These concerns are being evaluated by the Electric Power Research Institute (EPRI) Low Level NO_x Project, and the project has validated many of these concerns. While this project is still on going, the information to date suggests the potential trend of increasing ammonia injection rates to maintain low NO_x levels and difficulties in monitor performance. The latter included increased span drift and bias test failures during RATA testing. As a result of these monitoring issues, a longer averaging time is considered appropriate for a 2.5 ppmvd emission limit.

Environmental--There would also be collateral environmental consequences to achieve a NO_x emission rate of 2.5 ppmvd corrected to 15-percent O₂ rather than 3.5 ppmvd corrected to 15-percent O₂. This will be a direct result of increased backpressure on the turbine resulting from more catalyst volume required. Backpressure will increase by 15 percent over the proposed BACT emission rate resulting in increased energy losses and greater secondary emissions. Indeed, the lost energy will increase by 906,345 kW-hours/year/turbine or enough additional electric power to support about 76 residential customers for a year. To supply this lost energy, at least 1.0 TPY of additional criteria pollutants as well as 591 TPY of additional carbon dioxide would be generated.

Proposed BACT and Rationale

The proposed BACT is advanced DLN combustion technology and SCR. The proposed NO_x emissions level using this technology is 2.5 ppmvd corrected to 15-percent O₂ when firing natural gas and 10 ppmvd corrected to 15-percent O₂ when firing distillate light oil. This combination of the technology can achieve the maximum amount of emission reduction available, technically feasible and demonstrated for the Project. SCR cannot be rejected based on the economic, environmental, and energy impacts given the recent BACT decisions on other similar projects.

SCONO_xTM is rejected as BACT based on significant energy, environmental and economic impacts. The costs are significantly different between SCR and SCONO_xTM, yet both technologies can achieve the same level of NO_x reduction. From an environmental perspective, the only advantage of

SCONO_xTM is the lack of ammonia slip. Ammonia is an unregulated air pollutant and ammonia slip can be minimized through design and operation of the SCR system. SCONO_xTM requires steam and natural gas that SCR does not require. These have direct environmental consequences in the form of additional air pollutant emissions including about 23,000 TPY per unit of additional CO₂. Thus, the energy and other environmental disadvantages of SCONO_xTM outweigh any advantages in the reduction of these emissions. Taking together the energy, economic and environmental impacts and other costs, SCONO_xTM is rejected as BACT. In addition, the use of distillate light oil further limits the ability of SCONO_xTM to be used for the Project.

4.3.3 CARBON MONOXIDE

Technology Description

Emissions of CO are dependent on the combustor design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected. The CTs proposed for the Project have designs to optimize combustion efficiency and minimize NO_x emissions to the lowest achievable using DLN combustion technology while maintaining low CO emission levels.

For the Project, the following alternatives were evaluated as BACT:

1. Combustion controls, and
2. Oxidation catalyst at 2 ppmvd emission rate.

There are two alternatives for installing an oxidation catalyst. The first would be to install a catalyst prior to the HRSG to reduce CO emissions from the turbine. This would result in the CO emissions from the duct burners being uncontrolled. The second alternative is to install an oxidation catalyst or SCONO_xTM within the HRSG. This would control all the CO emissions, including CO from the duct burners. The capital cost for an oxidation catalyst and its technical feasibility is not different when considering simple or combined cycle operation.

Impact Analysis

Economic--The estimated capital cost for an oxidation catalyst installed in the HRSG is \$1.37 million. The annualized cost of a CO oxidation catalyst is \$621,000. The resulting cost effectiveness is approximately \$4,240 per ton of CO removed for gas and oil firing. No costs are associated with combustion techniques, since they are inherent in the design.

SCONO_xTM also reduces CO emissions. The incremental cost effectiveness for CO removal for this system is over \$27,000 per ton. This is based on the differential between the annualized cost of SCONO_xTM (\$5.1 million) and SCR (\$1.125 million) and the tons of CO potentially removed in the SCONO_xTM system.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Moreover, the air quality impacts, at the proposed CT emission rate, are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable AAQS. There would also be no secondary benefits, such as reductions in O₃ precursors and acidic deposition, to reducing CO.

In contrast, the installation of an oxidation catalyst would create additional back pressure on the turbine that will result in lost electric generation that would otherwise be available and thus replaced by older, less efficient technology. The end result is an additional 1,970 TPY of carbon dioxide (CO₂). The ultimate end product of CO is CO₂, regardless of whether the process results from an oxidation catalyst or in the atmosphere. The lost energy caused by the back pressure from the oxidation catalyst would result in the generation of 10 times more greenhouse gases than the amount of CO converted to CO₂ in the oxidation catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 1.5 to 2 inches of water gauge would be expected. A catalyst back pressure of 2 inches would result in an energy penalty of about 3 million kWh/yr. The energy penalties are sufficient to supply the electrical needs of about 252 residential customers for a year. To replace this lost energy, about 3.1×10^{10} Btu/yr or about 31 million ft³/yr of natural gas would be required. In contrast, the total energy requirements of SCONO_xTM is 38×10^{10} Btu/yr or about 380 million ft³/yr of natural gas.

Proposed BACT and Rationale

Combustion design is proposed as BACT, as there are adverse technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission rates for CO will not exceed 9 ppmvd when firing natural gas at baseload to 50-percent load, 17 ppmvd when firing natural gas with duct firing, and 20 ppmvd when firing distillate oil. Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts,
2. The economic impacts are significant (i.e., the capital cost is \$1.37 million, with an annualized cost of about \$621,000 per year per unit), and
3. Recent projects in Florida and Region IV have been authorized with BACT emission limits of similar magnitude.

SCONO_xTM is rejected as BACT based on the high differential costs of the technology. Also, the as described in the BACT evaluation for NO_x, the use of SCONO_xTM on a "F" Class turbine has associated technical uncertainty, as well as significant energy and environmental impacts.

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable, since it will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 9- to 25-ppmvd range when firing natural gas and distillate oil. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

The cost effectiveness calculations are significantly understated if the actual emission performance is considered. The actual CO emissions performance of the GE Frame 7FA turbines is much less than the guaranteed rates. This is a direct result of turbine manufacturers and duct burner vendors including significant margins on emissions of CO and VOCs to assure that NO_x emission guarantees can be achieved in the combustion systems. CO test data indicated that emissions range from 0.0 to 1.01 ppmvd (corrected to 15-percent O₂) with an average of 0.25 ppmvd (corrected to 15-percent O₂) when firing natural gas over loads from 50 percent to 100 percent. These data were from 67 tests. The GE guarantee is equivalent to 7.4 ppmvd corrected to 15-percent O₂ (i.e., 9 ppmvd) when firing natural gas. The actual CO emissions are over 10 times less than the guarantee emission level.

4.3.4 PM/PM₁₀, SO₂, AND SULFURIC ACID MIST

The PM/PM₁₀ emissions from the CTs are a result of incomplete combustion and trace elements in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas-fired or distillate oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs. The grain loading associated with the maximum particulate emissions (less than 20 lb/hr when firing natural gas) is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed Project.

There are no technically feasible methods for controlling the emissions of SO₂ and sulfuric acid mist from CTs, other than the inherent quality of the fuel. The use of flue gas desulfurization (FGD) systems are not available, technically feasible, demonstrated or cost effective on CTs using natural gas. The use of natural gas, a clean fuel, represents BACT and will limit emissions of SO₂.

4.3.5 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CTs as a result of incomplete combustion. The proposed emission rates for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions when firing natural gas will not exceed 1.4 ppmvw when firing natural gas at baseload and 2.6 ppmvw when duct firing. When firing distillate oil the emissions will not exceed 3.5 ppmvd. This emission level is similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

A review of the BACT/LAER Information System (BLIS) did not indicate any oxidation catalysts on natural gas fired combustion turbines to limit emissions of VOCs. A vendor of oxidation catalysts was contacted to determine the removal of VOCs in an oxidation catalyst typically used (i.e., primarily used for CO in nonattainment areas as LAER). The vendor stated that the typical VOC removal in a turbine application is from 30 to 40 percent. The cost effectiveness calculation is presented below:

VOC Cost Effectiveness Calculations

2.25 lb/hr gas firing at baseload
4.45 lb/hr gas firing at baseload w/duct firing
4.38 lb/hr gas firing power augmentation with duct firing
7.28 lb/hr oil firing
14.96 TPY
40.00% removal
5.98 TPY removal
103,809 per ton VOC removed
90.00% removal
13.46 TPY removed
\$46,137 per ton VOC removed

At 40-percent VOC removal the cost effectiveness of an oxidation catalyst is over \$100,000 per ton of VOC removed. Assuming that 90 percent reduction were available at the same cost, the cost effectiveness is over \$46,000 per ton of VOC removed.

Similar to the results for CO, the actual VOC emission rates have been extremely low when compared with the emission guarantees. VOC test data indicated that emissions range from 0.0 to 1.65 ppmvd (corrected to 15-percent O₂) with an average of 0.23 ppmvd (corrected to 15-percent O₂) when firing natural gas over loads from 50 to 100 percent. These data were from 34 tests. The GE guarantee is 1.4 ppmvw (corrected to 15-percent O₂). The actual VOC emissions are 5 times lower than the guarantee emission level. Test results for duct firing with natural gas suggest that VOC emission rates remain unchanged.

4.3.6 COOLING TOWER

For the cooling tower, the installation of drift eliminators is the only feasible technology for controlling PM emissions. Drift eliminators use inertial separation caused by airflow direction changes to remove water droplets from the air stream exhausting from the cooling tower. These water droplets generally contain the same concentration of dissolved solids and chemical impurities as the water circulating through the tower and can be converted to airborne emissions.

Drift eliminator configurations include cellular (or honeycomb), wave-form, and herringbone (blade-type) designs. Drift eliminators may include various materials such as wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles; ceramics, fiberglass, metal, and plastic.

Particulate emissions from the Project's cooling tower will be controlled utilizing high-efficiency drift eliminators achieving a drift loss rate of 0.001 percent of the cooling tower recirculating water flow.

Table 4-1. Proposed BACT Emission Limitations and Compliance Methods For Each CT/HRSG Unit

Pollutant	Fuel	Method of Operation	Emission Rate	Compliance Method
			(ppmvd @15% O ₂)	
Nitrogen Oxides	Gas	Combined Cycle (CC)	2.5	EPA Method 7E Initial Test; CEM 24-hr Block A
	Gas	CC - w/Duct Firing	2.5	EPA Method 7E Initial Test; CEM 24-hr Block A
	Gas	CC - w/Duct Firing, Power Aug.	2.5	EPA Method 7E Initial Test; CEM 24-hr Block A
	Oil	CC	10	EPA Method 7E Initial Test; CEM 24-hr Block A
Carbon Monoxide	Gas	CC	7.3	EPA Method 7E Initial Test; CEM 24-hr Block A
	Gas	CC - w/Duct Firing	10.2	EPA Method 7E Initial Test; CEM 24-hr Block A
	Gas	CC - w/Duct Firing, Power Aug.	14.7	EPA Method 7E Initial Test; CEM 24-hr Block A
	Oil	CC	20	EPA Method 7E Initial Test; CEM 24-hr Block A
Volatile Organic Compounds	Gas	CC	1.3	EPA Method 25 Initial Test
	Gas	CC - w/Duct Firing	2.6	EPA Method 25 Initial Test
	Gas	CC - w/Duct Firing, Power Aug.	2.5	EPA Method 25 Initial Test
	Oil	CC	2.8	EPA Method 25 Initial Test
Particulate Matter	Gas	CC	NA	Fuel Specification VE <10%
	Oil	CC	NA	Fuel Specification VE <20%
Sulfur Dioxide & Sulfuric Acid Mist (SAM)	Gas	CC	NA	Fuel Specification
	Oil	CC	NA	Fuel Specification (0.0015 % Sulfur)

Source: GE CT Performance Data; Golder, 2003.

Note: Based on maximum emission rates over turbine inlet operating conditions for all operating loads.

5.0 AMBIENT MONITORING ANALYSIS

The CAA requires that an air quality analysis be conducted for each criteria and noncriteria pollutant subject to regulation under the act before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Noncriteria pollutants are those pollutants that may be regulated by emission standards, but no AAQS have been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the estimated emissions from the Project (see Table 3-3), pre-construction ambient monitoring analyses for SO₂, PM₁₀, NO₂, CO, ozone (based on VOC emissions) and sulfuric acid mist are required to be submitted as part of the application. The ambient monitoring analysis is not required if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels and, for ozone (based on VOC emissions), VOC emission level of 100 TPY.

As shown in Table 3-4, when the Project is operating in combined cycle configuration, the Project's impacts are predicted to be below the applicable *de minimis* monitoring concentrations. In the case of ozone, the Project's VOC emissions are less than the monitoring emission level of 100 TPY. Therefore, pre-construction ambient monitoring analyses for the criteria pollutants, including ozone (based on VOC emissions), are not required to be submitted as part of the application.

For sulfuric acid mist, which is a noncriteria pollutant, although the Project's emissions are greater than the significant emission rate, EPA has established no acceptable monitoring method for this pollutant.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

6.1.1 SITE VICINITY

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels at any location beyond the plant's restricted boundaries.

If the project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida ambient air quality standards (AAQS), and the second analysis demonstrates compliance with allowable PSD Class II increments.

6.1.2 PSD CLASS I AREAS

Generally, if the facility undergoing the modification is within 200 kilometers of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the project alone at the PSD Class I area. The PSD Class I area of Everglades National Park is located approximately 21 km from the Project. Because Everglades National Park is located within 200 km of the Project, the maximum predicted impacts at the Everglades National Park are compared to EPA's proposed significant impact levels for PSD Class I areas. These recommended levels have never been promulgated as rules but are the currently accepted criteria to determine whether a proposed project will incur a significant impact on a PSD Class I area.

If the project-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then an analysis is performed to demonstrate compliance with allowable PSD Class I impacts at the PSD Class I area.

In addition, the project's maximum concentrations are evaluated at the PSD Class I area for pollutants whose emissions are greater than the significant emission rate, to address potential impacts on air quality related values (AQRV). This analysis includes an evaluation of regional haze degradation and acid deposition.

6.2 PRE-CONSTRUCTION MONITORING ANALYSIS APPROACH

The modeling approach followed EPA and FDEP modeling guidelines for evaluating a project's impacts relative to the *de minimis* monitoring levels to determine the need to submit ambient monitoring data prior to construction. Current FDEP policies stipulate that the predicted highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

6.3 AIR MODELING ANALYSIS APPROACH

6.3.1 GENERAL PROCEDURES

As stated in the previous sections, for each pollutant which is emitted above the significant emission rate, air modeling analyses are required to determine if the Project's impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels. These analyses consider the Project's impacts alone. Air quality impacts are predicted using 5 years of meteorological data and selecting the highest predicted ground-level concentrations for comparison to the significant impact levels and *de minimis* monitoring levels.

To predict the maximum annual and short-term concentrations for the proposed Project, the modeling approach was divided into screening and refined phases. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record. If the highest concentration is predicted at a receptor that lies in an area where the receptor spacing is more than 100 m, then a refined analysis is performed in that area using a receptor grid of greater resolution. Modeling refinements are performed using a receptor spacing of 100 m with a receptor grid centered on the screening receptor at which the maximum concentration was predicted. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred.

If the Project's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations to predict a total concentration for comparison to AAQS. Because the proposed Project's maximum 24-hour SO₂ impacts are predicted to be greater than the significant impact level, additional AAQS and PSD Class II Increment analyses were performed for this pollutant and averaging time.

Generally, when using 5-years of meteorological data for the analysis, the highest annual and the highest, second-highest (HSH) short-term concentrations are compared to the applicable AAQS and allowable PSD increments. [Note that for determining compliance with the 24-hour AAQS for PM_{10} , the sixth highest predicted concentration in five years (i.e., H6H), instead of the HSH, is used to compare to the applicable 24-hour AAQS.]

The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

The HSH approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

The AAQS analysis is a cumulative source analysis that evaluates whether the concentrations from all sources will comply with the AAQS. These concentrations include the modeled impacts from sources at the project site and from other nearby facility sources added to a background concentration. The background concentration accounts for sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at the project site, plus nearby PSD increment-affecting sources at other facilities.

6.3.2 PSD CLASS I ANALYSIS

For each pollutant for which a significant impact is predicted at the PSD Class I area, a PSD Class I analysis is required. The PSD Class I analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources located within 200 km of the PSD Class I area will comply with the allowable PSD Class I increments. These concentrations include the impacts from PSD increment-affecting sources at the project site, plus the impacts from PSD increment-affecting sources at other facilities.

6.4 **MODEL SELECTION**

The selection of an air quality model to calculate air quality impacts for the Project was based on its applicability to simulate impacts in areas surrounding the Project as well as at the PSD Class I area of interest. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for the Project. These models were:

- The Industrial Source Complex Short Term (ISCST3) dispersion model, and
- The California Puff model (CALPUFF).

The ISCST3 (Version 02035) dispersion model (EPA, 2002) was used to evaluate the pollutant impacts due to the Project in nearby areas surrounding the Site. This model is maintained by the EPA on its internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

In this analysis, the EPA regulatory default options were used to predict maximum impacts. The ISCST3 model can be executed in the rural or urban land use mode that affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent land use within a 3-km radius around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land-use within a 3-km radius of the Project, the rural dispersion coefficients were used in the modeling analysis. Also, since the terrain around the facility is flat to gently rolling, the simple terrain feature of the model was selected. The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times.

Because the Project is within 50 km of the PSD Class I area of Everglades National Park, the ISCST model was used to perform a significant impact analysis at the PSD Class I area.

At distances beyond 50 km from a source, the CALPUFF model, Version 5.5 (EPA, 2002), is recommended for use by the EPA and the Federal Land Manager (FLM). The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The CALPUFF model is maintained by the EPA on the SCRAM internet website. The methods and assumptions used in the CALPUFF model are based on the latest recommendations for modeling analysis as presented in the following reports:

- The Interagency Workgroup on Air Quality Models (IWAQM), *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998); and
- The *Federal Land Manager's Air Quality Relative Values Workgroup (FLAG) Phase I Report* (December, 2000).

In addition, updates to the modeling methods and assumptions were followed based on discussion with the FLM.

The CALPUFF model was used to assess the Project's impact on regional haze at distances and total nitrogen and sulfur deposition levels. A more detailed description of the assumptions and methods used for the CALPUFF model is presented in Table 6-2 and in Appendix C.

As discussed in Section 6-10, the Project's were predicted to be greater than the proposed PSD Class I significant impact levels for the 3-hour and 24-hour averaging periods for SO₂ and the 24-hour averaging period for PM₁₀. As a result, cumulative source impact analyses are required to demonstrate compliance with the 3-hour and 24-hour average SO₂ and 24-hour average PM₁₀ PSD Class I increments. The detailed modeling involved assessing air quality impacts from PSD sources located within about 200 km from the Everglades National Park. As shown in Tables 6-3 and 6-4, a majority of these PSD sources are located more than 50 km from the Everglades National Park. Based on previous discussions with the Florida DEP and National Park Service, these analyses should be performed using a long-range transport model that can assess impacts for sources located within 50 km as well as more than 50 km from the PSD Class I area and is acceptable to the Florida DEP, EPA, and National Park Service. From those discussions, the CALPUFF long-range transport model was recommended and determined to be acceptable by the reviewing agencies. As a result, the CALPUFF model was used to assess the 3-hour and 24-hour average SO₂ and 24-hour average PM₁₀ concentrations for PSD sources, including the Project, located within 200 km of the PSD Class I area to determine compliance with the PSD Class I increments.

6.5 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) office located at the Miami International Airport (MIA). The 5-year period of meteorological data was from 1987 through 1991. The NWS office at MIA is located approximately 50 km north of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. The MIA station meteorological data have been approved by the FDEP and used for numerous air modeling studies submitted as part of air construction permits approved for sources located in Miami-Dade County.

CALMET, the meteorological preprocessor to CALPUFF, was used to develop a 3-dimensional wind field necessary to perform the air modeling analysis to evaluate pollutant impacts at each PSD Class I area. The modeling domain consisted of a rectangular 3-dimensional grid that extended from approximately 79.0 to 83.5 degrees longitude and from 23.75 to 28.0 degrees latitude. The modeling domain includes the following meteorological and land use parameters:

- Surface weather data,
- Upper air data,
- A 1-degree land use data,
- A 1-degree Digital Elevation Model (DEM) terrain data,
- Mesoscale Model - Generations 4 and 5 (MM4 and MM5) data (for initializing the wind field), and
- Hourly precipitation data.

These data were obtained and processed for 1990, 1992, and 1996, the years for which MM4 and MM5 data are available on CD. It should be noted that MM4 data are available for 1990 while MM5 data are available for 1992 and 1996. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the FLMS. Meteorological data used with the CALPUFF model consist of a CALMET-developed wind field covering south Florida. More detailed descriptions of the assumptions and methods used for processing the meteorological data and establishing the model domain are presented in Appendix C.

6.6 EMISSION INVENTORY

6.6.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTs, operating in combined cycle configuration, that were used in the air modeling analysis are presented in Tables 2-1 and 2-2. The emission and stack operating parameters presented are for 3 operating loads and 35°F, 59°F and 95°F ambient temperatures for the CTs firing natural gas and oil. Additional operating cases were also considered that included power augmentation and HPM for the CTs firing natural gas. In an effort to obtain the maximum air quality impacts for a range of possible operating conditions, the air modeling used a range of emission rates and stack parameter data to predict air quality impacts.

A total of 21 modeling scenarios were also considered for combined cycle configuration with the CTs operating for the following conditions:

- CTs firing natural gas for ambient temperatures of 35, 59, and 95°F at:
 - 100 percent operating load with duct firing
 - 75 percent operating load
 - 50 percent operation load
 - power augmentation load with duct firing at 80°F
- CTs firing oil for ambient temperatures of 35, 59, and 95°F at:
 - 100 percent operating load
 - 75 percent operating load
 - 50 percent operation load

The proposed CTs will have a HRSG stack height of 131 ft and an inner stack diameter of 19 ft. Because the proposed stack heights are less than GEP, building downwash effects were included in the modeling analysis (see following section on building downwash). The relative locations of the stacks used in the modeling analysis were:

Stacks	Relative Location (m)	
	X	Y
HRSO Stack No. A	0.0	0.0
HRSO Stack No. B	42.5	0.0
HRSO Stack No. C	128.0	0.0
HRSO Stack No. D	170.7	0.0

The air modeling origin was assumed to be located at HRSO Stack A. For PSD Class I modeling, the modeling origin was assumed to be located at UTM east and north coordinates of 567,000 and 2,813,500 m, respectively, in UTM Zone 17.

The ISCST3 model was used to predict maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. To estimate impacts due to emissions from the stacks, an emission rate of 79.365 pounds per hour (lb/hr) or 10 grams per second (g/s) was initially used to produce relative concentrations as a function of the modeled emission rate (i.e., $\mu\text{g}/\text{m}^3$ per 10 g/s). These impacts are referred to as generic pollutant impacts. Maximum air quality impacts for specific pollutants were then determined by multiplying the maximum pollutant-specific emission rate in lb/hr (g/s) by the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

For the PSD Class I area of the Everglades National Park, regional haze and sulfur and nitrogen deposition analyses were performed for the Project for combined cycle operation with the CALPUFF model based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the CTs operating for 100-percent load conditions. Appendix A contains a description of operating conditions and pollutant specifications

Annual average concentrations predicted in the near-field of the plant are based on the operating scenarios with the maximum hourly emissions for the following annual hours:

- For SO_2 and PM_{10} : combined cycle operation with natural gas firing for 8,760 hours; and
- For NO_2 : combined cycle operation with natural gas- and light oil-firing for 8,260 and 500 hours, respectively.

For the PSD Class I area, the annual average concentrations are based on the following:

- For SO₂: combined cycle operation with natural gas firing for 8,760 hours; and
- For PM₁₀ and NO₂: combined cycle operation with natural gas- and light oil-firing for 8,260 and 500 hours, respectively.

6.6.2 AAQS AND PSD CLASS II ANALYSES

As discussed in Section 6.10, the maximum impacts from the Project were predicted to be less than the significant impact levels for all pollutants. As a result a cumulative source analysis is not required to demonstrate compliance with the AAQS and PSD Class II increments. Therefore, emission inventories for background sources were not developed.

6.6.3 PSD CLASS I ANALYSIS

The maximum Project impacts at the PSD Class I area of the Everglades National Park are predicted to be less than the proposed PSD Class I significant impact levels for the annual averaging periods for SO₂, PM₁₀, and NO₂ but greater than the 3-hour and 24-hour averaging periods for SO₂ and the 24-hour averaging period for PM₁₀. As a result, cumulative source impact analyses are required to demonstrate compliance with the 3-hour and 24-hour average SO₂ and 24-hour average PM₁₀ PSD Class I increments.

A listing of background SO₂ and PM₁₀ sources that were used in the PSD Class I analyses and their locations relative to the PSD Class I area of the Everglades National Park are provided in Tables 6-3 and 6-4, respectively. PSD sources located within 200 km of the Everglades National Park were included in the PSD Class I modeling analysis. Detailed SO₂ and PM₁₀ background source data that were used for the PSD Class I analyses are presented in Appendix D.

6.7 RECEPTOR LOCATIONS

6.7.1 SITE VICINITY

To determine the maximum impact for all pollutants and averaging times in the Project's vicinity, concentrations were predicted at receptors located in a detailed receptor grids centered on HRSG Stack No. A, the modeling origin, that extended from the plant property out to 15 km.

A Cartesian receptor grid was used to predict concentrations for the Project at 50-m intervals along the plant boundary. A discrete polar grid was used to predict concentrations from the plant boundary

along 72 radials, spaced at 5-degree intervals, out to 2,000 m. Receptors were located every 100 m along each radial.

In addition, a general polar grid was used to predict concentrations from 2.25 to 15.0 km. This grid was comprised of 36 radials, spaced at 10-degree intervals along each radial. Receptors were located at the following distances from the origin:

- Every 250 m from 2.25 km to 7.0 km; and
- Every 500 m from 7.5 km to 15 km.

More than 2,000 receptors were used in the analysis to determine the maximum impacts for the Project.

6.7.2 CLASS I AREA

Maximum pollutant concentrations were predicted with the ISCST3 model using 126 discrete receptors located along the border of the PSD Class I area of the Everglades National Park. These receptors were also used in the AQRV analysis to address the Project's impacts on regional haze and sulfur and nitrogen deposition. A listing of Class I receptors used in the modeling analysis is provided in Table 6-5.

6.8 BACKGROUND CONCENTRATIONS

When a cumulative source analysis is required to demonstrate compliance with AAQS, a background concentration must be added to the impacts from modeled sources to estimate total air quality concentrations in the site vicinity. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation. However, because the maximum impacts from the Project were predicted to be less than the significant impact levels for all pollutants and a cumulative source analysis was not required, background concentrations were not developed.

6.9 BUILDING DOWNWASH EFFECTS

All significant building structures in the Project area were identified by the site plot plan (see Figure 2-2). The building structures were processed in the EPA Building Input Profile (BPIP, Version 95086) program to determine direction-specific building heights and widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of

dimensions for each structure is presented in Table 6-6. See Appendix E for plots of these building structures.

6.10 MODEL RESULTS

6.10.1 PSD CLASS II SIGNIFICANT IMPACT ANALYSIS

The maximum pollutant concentrations predicted for the Project by operating load and air inlet temperature for combined cycle operation are given in Table 6-7. A summary of the predicted maximum SO₂, NO_x, CO, and PM₁₀ concentrations predicted for the Project for the PSD Class II significant impact analysis is presented in Table 6-8.

The modeling results indicated that maximum concentrations due to the Project are predicted to be less than the significant impact levels for all pollutants. As a result, additional modeling analyses were not required to demonstrate compliance with AAQS and PSD Class II increments.

6.10.2 PSD CLASS I SIGNIFICANT IMPACT ANALYSIS

The maximum pollutant concentrations predicted for the Project by operating load and air inlet temperature for combined cycle operations at the PSD Class I area of the Everglades National Park are given in Table 6-9. A summary of the predicted maximum SO₂, NO_x, CO, and PM₁₀ concentrations predicted for the Project for the PSD Class I significant impact analysis is presented in Table 6-10.

The maximum Project impacts at the PSD Class I area of the Everglades National Park are predicted to be less than the proposed PSD Class I significant impact levels for the annual averaging periods for SO₂, PM₁₀, and NO₂ for the combined cycle operations when firing either natural gas or light oil.

For the 3-hour and 24-hour average SO₂ concentrations, the maximum Project impacts are predicted to be less than the significant impact levels for combined cycle operation when firing light oil. However, for combined cycle operation when firing natural gas, the maximum Project SO₂ impacts are predicted to be greater than the 3-hour and 24-hour significant impact levels.

For the 24-hour average PM₁₀ concentrations, the maximum Project impacts are predicted to be greater than the significant impact levels for combined cycle operation when firing both fuels.

As a result, cumulative source impact analyses are required to demonstrate compliance with the 3-hour and 24-hour average SO₂ and 24-hour average PM₁₀ PSD Class I increments.

6.10.3 CUMULATIVE PSD CLASS I INCREMENT ANALYSIS

A summary of the results of the cumulative PSD Class I increment analyses (i.e., impacts due to PSD increment consuming sources) for the 3-hour and 24-hour average SO₂ and 24-hour average PM₁₀ concentrations are presented in Tables 6-11 and 6-12, respectively.

The highest, second-highest 3-hour and 24-hour average SO₂ concentrations for Unit 5 and all other PSD increment consuming sources are 17.5 and 4.10 µg/m³, respectively, which are below the respective allowable 3-hour and 24-hour PSD Class I increments of 25 and 5 µg/m³.

The highest, second-highest 24-hour average PM₁₀ concentration of Unit 5 and all other PSD increment consuming sources is 2.15 µg/m³, which is below the allowable 24-hour PSD Class I increment 5 µg/m³.

6.10.4 CONCLUSIONS

Based on these air quality modeling analyses, the maximum pollutant concentrations due to the Project's emissions are predicted to be less than the PSD Class II and I significant impact levels for all pollutants except for the 3-hour and 24-hour average SO₂ and 24-hour average PM₁₀ PSD Class I significant impact levels for certain operations. As a result, more detailed SO₂ and PM₁₀ modeling analyses were performed with background sources to address compliance with the PSD Class I increments. The results of the modeling analysis demonstrate the Project will not have a significant affect on air quality and will comply with all applicable AAQS and PSD increments.

Table 6-1. Major Features of the ISCST3 Model, Version 02035

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations • Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations • Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979). • Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects • Procedures suggested by Briggs (1974) for evaluating stack-tip downwash • Separation of multiple emission sources • Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations • Capability of simulating point, line, volume, area, and open pit sources • Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition • Variation of wind speed with height (wind speed-profile exponent law) • Concentration estimates for 1 hour to annual average times • Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain • Consideration of time-dependent exponential decay of pollutants • The method of Pasquill (1976) to account for buoyancy-induced dispersion • A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used) • Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term

References:

- Bowers, J.F., J.R. Bjorklund and C.S. Cheney. 1979. Industrial Source Complex (ISC) Dispersion Model User's Guide. Volume I, EPA-450/4-79-030; Volume II. EPA-450/4-79-031. U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.
- Briggs, G.A. 1969. Plume Rise, USAEC Critical Review Series, TID-25075. National Technical Information Service, Springfield, Virginia 22161.
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- Briggs, G.A. 1979. Some Recent Analyses of Plume Rise Observations. In: Proceedings of the Second International Clean Air Congress. Academic Press, New York.
- Huber, A.H. 1977. Incorporating Building/Terrain Wake Effects on Stack Effluents. Preprint Volume for the Joint Conference on Applications of Air Pollution Meteorology, American Meteorological Society, Boston, Massachusetts.
- Huber, A.H. and W.H. Snyder. 1976. Building Wake Effects on Short Stack Effluents. Preprint Volume for the Third Symposium on Atmospheric Diffusion and Air Quality, American Meteorological Society, Boston, Massachusetts.
- Pasquill, F. 1976. Atmospheric Dispersion Parameters in Gaussian Plume Modeling - Part II. Possible Requirements for Change in the Turner Workbook Values. EPA-600/4-76-030b, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.
- Schulman, L.L. and J.S. Scire. 1980. Buoyant Line and Point Source (BLP) Dispersion Model User's Guide. Document P-7304B, Environmental Research and Technology, Inc., Concord, MA.

Table 6-2. Major Features of the CALPUFF Model, Version 5.5

CALPUFF Model Features

- Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant)
- Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates)
- Efficient sampling function (integrated puff formulation; elongated puff (slug) formation)
- Dispersion coefficient options (Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values)
- Vertical wind shear (puff splitting; differential advection and dispersion)
- Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer)
- Building downwash effects (Huber-Snyder method; Schulman-Scire method)
- Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS)
- Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS)
- Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none)
- Overwater and coastal interaction effects (overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells)
- Chemical transformation options (Pseudo-first-order chemical mechanisms for SO₂, SO₄, HNO₃, and NO₃; Pseudo-first-order chemical mechanisms for SO₂, SO₄, NO, NO₂, HNO₃, and NO₃ (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions)
- Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type)
- Graphical user interface
- Interface utilities (scan ISCST3 and AUSPLUME meteorological data files for problems; translate ISCST3 and AUSPLUME input files to CALPUFF input files)

Note: CALPUFF = California Puff Model

Source: EPA, 2000.

Table 6-3. Summary of Facilities with SQ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	County	UTM Coordinates		Relative to Everglades National Park			
			East (km)	North (km)	x (km)	y (km)	Distance ^a (km)	Direction (deg)
0250348	Miami-Dade RRF/Montenay	Dade	564.8	2857.6	14.8	9.0	17.3	59
0250020	Tarmac	Dade	562.9	2861.7	12.9	13.1	18.4	45
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	29.6	34.7	45.6	40
0110037	FPL -Lauderdale	Broward	580.1	2883.3	30.1	34.7	45.9	41
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	33.6	59.0	67.9	30
0112545	El Paso Broward Energy Center	Broward	583.3	2908.0	33.3	59.4	68.1	29
0710019	Lee County Resource Recovery	Lee	424.0	2946.0	-30.0	82.8	88.1 ^b	340
0990005	Okeelanta	Palm Beach	525.0	2937.4	-25.0	88.8	92.3	344
0990332	New Hope Power Partnership (Okeelanta)	Palm Beach	524.1	2940.0	-25.9	91.4	95.0	344
0710000	FPL - Fort Myers	Lee	422.1	2952.9	-31.9	89.7	95.2 ^b	340
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	2.9	96.6	96.6	2
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	33.6	94.4	100.2 ^b	20
0990568	Lake Worth Utilities	Palm Beach	592.8	2943.7	42.8	95.1	104.3	24
0990026	Sugar Cane Growers Coop.	Palm Beach	534.9	2953.3	-15.1	104.7	105.8	352
0990594	El Paso Belle Glade Generating Station	Palm Beach	533.5	2954.1	-16.5	105.5	106.8	351
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	52.1	93.7	107.2 ^b	29
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	35.8	111.6	117.2	18
0990019	Osceola Farms	Palm Beach	544.2	2968.0	-5.8	119.4	119.5	357
0990061	U.S. Sugar -Bryant	Palm Beach	537.8	2969.1	-12.2	120.5	121.1	354
0990021	Pratt & Whitney (United Technologies)	Palm Beach	567.3	2974.4	17.3	125.8	127.0	8
0850102	Bechtel Indiantown	Martin	545.6	2991.5	-4.4	142.9	143.0	358
0850001	FPL -Martin	Martin	543.1	2992.9	-6.9	144.3	144.5	357

^a Distance from the northeastern corner of the Everglades National Park, UTM East and North coordinates (km) of

550.0 and 2848.6 , respectively, unless noted.

^b Distance from the northwestern corner of the Everglades National Park, UTM East and North coordinates (km) of

454.0 and 2863.2 , respectively.

Table 6-4. Summary of Facilities with PM10 Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	County	UTM Coordinates		Relative to Everglades National Park			
			East (km)	North (km)	x (km)	y (km)	Distance ^a (km)	Direction (deg)
0250348	Miami-Dade RRF/Montenay	Dade	564.8	2857.6	14.8	9.0	17.3	59
0250020	Tarmac	Dade	562.9	2861.7	12.9	13.1	18.4	45
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	29.6	34.7	45.6	40
0110037	FPL -Lauderdale	Broward	580.1	2883.3	30.1	34.7	45.9	41
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	33.6	59.0	67.9	30
0112545	El Paso Broward Energy Center	Broward	583.3	2908.0	33.3	59.4	68.1	29
0710019	Lee County Resource Recovery	Lee	424.0	2946.0	-30.0	82.8	88.1 ^b	340
0990005	Okeelanta	Palm Beach	525.0	2937.4	-25.0	88.8	92.3	344
0990332	New Hope Power Partnership (Okeelanta)	Palm Beach	524.1	2940.0	-25.9	91.4	95.0	344
0710000	FPL - Fort Myers	Lee	422.1	2952.9	-31.9	89.7	95.2 ^b	340
0990016	Atlantic Sugar Association	Palm Beach	552.9	2945.2	2.9	96.6	96.6	2
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	33.6	94.4	100.2 ^b	20
0990568	Lake Worth Utilities	Palm Beach	592.8	2943.7	42.8	95.1	104.3	24
0990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-15.1	104.7	105.8	352
0990594	El Paso Belle Glade Generating Station	Palm Beach	533.5	2954.1	-16.5	105.5	106.8	351
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	52.1	93.7	107.2 ^b	29
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	35.8	111.6	117.2	18
0990019	Osceola Farms	Palm Beach	544.2	2968.0	-5.8	119.4	119.5	357
0990061	U.S. Sugar -Bryant	Palm Beach	537.8	2969.1	-12.2	120.5	121.1	354
0990021	Pratt & Whitney (United Technologies)	Palm Beach	567.3	2974.4	17.3	125.8	127.0	8
0850102	Bechtel Indiantown	Martin	545.6	2991.5	-4.4	142.9	143.0	358
0850001	FPL -Martin	Martin	543.1	2992.9	-6.9	144.3	144.5	357

^a Distance from the northeastern corner of the Everglades National Park, UTM East and North coordinates (km) of

550.0 and 2848.6 , respectively, unless noted.

^b Distance from the northwestern corner of the Everglades National Park, UTM East and North coordinates (km) of

454.0 and 2863.2 , respectively.

Table 6-5. Receptors Used for Modeling the PSD Class I Area of the Everglades National Park

UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)	
East	North	East	North	East	North	East	North
557000	2789000	538000	2848600	514500	2837000	470000	2860000
556600	2792000	537000	2848600	514500	2836000	469000	2860000
556000	2796000	536000	2848600	514500	2835000	468000	2860000
553000	2796500	535000	2848600	514500	2834000	467000	2860000
548000	2796500	534000	2848600	514500	2833000	466000	2860000
542700	2796500	533000	2848600	514500	2832500	465000	2860000
542700	2800000	532000	2848600	510000	2832500	464000	2860000
542700	2805000	531000	2848600	509000	2832500	463000	2860000
542700	2810000	530000	2848600	508000	2832500	462000	2860000
542000	2811000	529000	2848600	507000	2832500	461000	2860000
541300	2814000	528000	2848600	506000	2832500	460000	2860000
542700	2816000	527000	2848600	505000	2832500	459500	2863200
544100	2820000	526000	2848600	504000	2832500	459000	2863200
543500	2824600	525000	2848600	503000	2832500	458000	2863200
545000	2829000	524000	2848600	502000	2832500	457000	2863200
545700	2832200	523000	2848600	501000	2832500	456000	2863200
546200	2835700	522000	2848600	500000	2832500	455000	2863200
548600	2837500	521000	2848600	499000	2832500	454000	2863200
550300	2839000	520000	2848600	498000	2832500		
545000	2839000	519000	2848600	497000	2832500		
540000	2839000	518000	2848600	496000	2832500		
550500	2844000	517000	2848600	495000	2832500		
545000	2844000	516000	2848600	495000	2833000		
540000	2844000	515000	2848600	495000	2834000		
550300	2848600	514500	2848600	495000	2835000		
549000	2848600	514500	2848000	495000	2836000		
548000	2848600	514500	2847600	494500	2837000		
547000	2848600	514500	2846600	491500	2841000		
546000	2848600	514500	2845000	488500	2845500		
545000	2848600	514500	2844000	483000	2848500		
544000	2848600	514500	2843000	480000	2852500		
543000	2848600	514500	2842000	475000	2854000		
542000	2848600	514500	2841000	473500	2857000		
541000	2848600	514500	2840000	473000	2860000		
540000	2848600	514500	2839000	472000	2860000		
539000	2848600	514500	2838000	471000	2860000		

Note: FPL Turkey Point Plant's UTM East and North coordinates are
567,000 and 2,813,500 m, respectively.
UTM = Universal Transverse Mercator
m = meter

Table 6-6. Project Building Dimensions Used in the Modeling Analysis

Structure	Height		Length		Width	
	ft	m	ft	m	ft	m
CT Inlet Structure A	66.9	20.4	45.4	13.8	17.4	5.3
HRSG Structure A	86.9	26.5	101.7	31.0	38.0	11.6
CT Inlet Structure B	66.9	20.4	45.4	13.8	17.4	5.3
HRSG Structure B	86.9	26.5	101.7	31.0	38.0	11.6
CT Inlet Structure C	66.9	20.4	45.4	13.8	17.4	5.3
HRSG Structure C	86.9	26.5	101.7	31.0	38.0	11.6
CT Inlet Structure D	66.9	20.4	45.4	13.8	17.4	5.3
HRSG Structure D	86.9	26.5	101.7	31.0	38.0	11.6
Cooling Tower	51	15.5	661	201.5	114.0	34.8

Notes: CT= combustion turbine; HRSG= heat recovery steam generator.

Top of platform shown in Figure 2-3 is 93 ft. The platform is made of steel grating and is porous. Actual height of HRSG is 83 ft. A height of 87 ft was used to account for equipment between 83 and 93 ft.

Table 6-7. Maximum Pollutant Concentrations Predicted for the Project by Operating Load and Air Inlet Temperature for Combined Cycle Operation

Maximum Predicted Concentrations (ug/m ³) by Operating Load and Air Inlet Temperature ^a															
Pollutant	Averaging Time	Power Aug.	Higher Power Mode				100% Load			75% Load			50% Load		
		80°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	
<u>Natural Gas Operation ^b</u>															
SO ₂	Annual	0.140	0.082	0.086	0.088	0.123	0.127	0.131	0.111	0.108	0.106	0.130	0.126	0.117	
	24-Hour	2.23	1.46	1.50	1.50	2.05	2.09	2.10	1.71	1.68	1.65	1.86	1.82	1.71	
	3-Hour	7.73	4.74	4.89	5.04	6.70	6.94	7.25	6.16	6.06	6.04	6.96	6.81	6.42	
PM ₁₀	Annual	0.159	0.086	0.093	0.100	0.134	0.142	0.156	0.143	0.144	0.152	0.203	0.203	0.202	
	24-Hour	2.54	1.54	1.61	1.71	2.23	2.33	2.49	2.22	2.24	2.36	2.91	2.93	2.97	
NO ₂	Annual	0.246	0.136	0.142	0.145	0.225	0.235	0.245	0.183	0.178	0.174	0.211	0.205	0.190	
CO	8-Hour	29.6	17.1	17.1	17.0	19.7	20.2	20.7	12.3	12.1	12.0	13.9	13.6	13.0	
	1-Hour	72.6	42.6	42.5	42.3	48.3	49.5	50.9	29.5	28.8	28.1	30.8	30.1	28.6	
<u>Fuel Oil Operation</u>															
SO ₂	Annual	NA	NA	NA	NA	0.0114	0.0119	0.0122	0.0157	0.0154	0.0147	0.0182	0.0176	0.0161	
	24-Hour	NA	NA	NA	NA	0.241	0.245	0.249	0.303	0.299	0.288	0.337	0.329	0.307	
	3-Hour	NA	NA	NA	NA	0.80	0.81	0.80	1.01	1.00	0.99	1.21	1.18	1.11	
PM ₁₀	Annual	NA	NA	NA	NA	0.065	0.071	0.080	0.112	0.114	0.118	0.163	0.163	0.162	
	24-Hour	NA	NA	NA	NA	1.37	1.46	1.63	2.15	2.21	2.32	3.02	3.04	3.07	
NO ₂	Annual	NA	NA	NA	NA	0.293	0.305	0.314	0.398	0.392	0.374	0.459	0.444	0.406	
CO	8-Hour	NA	NA	NA	NA	13.0	13.2	13.5	16.1	16.0	15.7	18.9	18.5	17.8	
	1-Hour	NA	NA	NA	NA	36.9	37.3	37.9	42.6	42.1	40.9	46.4	45.6	43.6	

Note: NA = not applicable

^a Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service stations at Miami and Palm Beach International Airports, respectively.

^b Duct firing included for power augmentation and 100 % load operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of

550 mmBtu/hr (HHV).

Table 6-8. Summary of Maximum Pollutant Concentrations Predicted for the Project, Compared to the EPA Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m ³)			EPA Class II Significant Impact Levels (ug/m ³)
		Combined Cycle Natural Gas	Combined Cycle Fuel Oil	Maximum	
CTs Only					
SO ₂	Annual	0.14	0.018	0.14 ^a	1
	24-Hour	2.23	0.34	2.23	5
	3-Hour	7.73	1.21	7.73	25
PM ₁₀	Annual	0.20	0.16	0.20 ^a	1
	24-Hour	2.97	3.07	3.07	5
NO ₂	Annual	0.25	0.46	0.26 ^a	1
CO	8-Hour	29.6	18.9	29.6	500
	1-Hour	72.6	46.4	72.6	2,000
CTs and Cooling Tower					
PM ₁₀	Annual	0.21	0.19	0.21	1
	24-Hour	3.15	3.70	3.70	5

Note: NM = not modeled.

^a Maximum annual average concentration are based on prorating the maximum impacts for each operation by the following maximum number of hours requested for that operation:

Pollutant	Hours for Each Operation		
	Combined Cycle Natural Gas	Combined Cycle Fuel Oil	Total
SO ₂	8,760	0	8,760
PM ₁₀	8,760	0	8,760
NO ₂	8,260	500	8,760

Table 6-9. Maximum Pollutant Concentrations Predicted for the Project by Operating Load and Air Inlet Temperature for Combined Cycle Operation
PSD Class I Area of the Everglades National Park

		Maximum Predicted Concentrations (ug/m ³) by Operating Load and Air Inlet Temperature *													
Pollutant	Averaging Time	Power Aug.	Higher Power Mode				100% Load			75% Load			50% Load		
		80°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	
Natural Gas Operation ^b															
SO ₂	Annual	0.037	0.028	0.028	0.027	0.037	0.037	0.035	0.026	0.025	0.023	0.023	0.022	0.020	
	24-Hour	0.38	0.29	0.29	0.28	0.38	0.38	0.36	0.26	0.25	0.23	0.24	0.23	0.21	
	3-Hour	1.76	1.25	1.24	1.19	1.69	1.69	1.65	1.28	1.24	1.18	1.32	1.28	1.18	
PM ₁₀	Annual	0.042	0.030	0.030	0.030	0.041	0.041	0.042	0.033	0.033	0.033	0.036	0.036	0.035	
	24-Hour	0.43	0.31	0.31	0.31	0.42	0.42	0.42	0.33	0.33	0.33	0.38	0.37	0.37	
NO ₂	Annual	0.065	0.047	0.046	0.044	0.068	0.068	0.066	0.042	0.041	0.038	0.037	0.036	0.033	
Fuel Oil Operation															
SO ₂	Annual	NA	NA	NA	NA	0.0062	0.0061	0.0058	0.0060	0.0058	0.0054	0.0054	0.0052	0.0048	
	24-Hour	NA	NA	NA	NA	0.068	0.066	0.063	0.064	0.061	0.057	0.055	0.054	0.049	
	3-Hour	NA	NA	NA	NA	0.26	0.26	0.24	0.26	0.25	0.23	0.24	0.23	0.21	
PM ₁₀	Annual	NA	NA	NA	NA	0.035	0.036	0.038	0.043	0.043	0.044	0.048	0.048	0.048	
	24-Hour	NA	NA	NA	NA	0.39	0.40	0.41	0.45	0.45	0.46	0.50	0.50	0.49	
NO ₂	Annual	NA	NA	NA	NA	0.16	0.16	0.15	0.15	0.15	0.14	0.14	0.13	0.12	

Note: NA = not applicable

^a Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service stations at Miami and Palm Beach International Airports, respectively.

^b Duct firing included for power augmentation and 100 % load operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of

550 mmBtu/hr (HHV).

Table 6-10. Summary of Maximum Pollutant Concentrations Predicted for the Project, Compared to the EPA Class I Significant Impact Levels
PSD Class I Area of the Everglades National Park

Pollutant	Averaging Time	Maximum Predicted Concentration (µg/m ³)			EPA Class I Significant Impact Levels (µg/m ³)
		Natural Gas	Fuel Oil	Maximum	
CTs Only					
SO ₂	Annual	0.037	0.0062	0.037 ^a	0.1
	24-Hour	0.38	0.068	0.38	0.2
	3-Hour	1.76	0.26	1.76	1.0
PM ₁₀	Annual	0.042	0.048	0.043 ^a	0.2
	24-Hour	0.43	0.50	0.50	0.3
NO ₂	Annual	0.068	0.16	0.073 ^a	0.1

Note: NM = not modeled.

^a Maximum annual average concentration are based on prorating the maximum impacts for each operation by the following maximum number of hours requested for that operation:

Pollutant	Hours for Each Operation		
	Natural Gas	Fuel Oil	Total
SO ₂	8,760	0	8,760
PM ₁₀	8,260	500	8,760
NO ₂	8,260	500	8,760

Table 6-11. Maximum Predicted SO₂ Impacts For Comparison to the PSD Class I Increments

Rank and Averaging Time	Concentration (µg/m ³) ^a	Receptor UTM Location (km)		Time Period (Year, Julian Day, Hour Ending)	PSD Class I Increment (µg/m ³)
	Modeled Sources	East	North		
HSH 3-Hour	9.60	550.3	2848.6	1990,300,0500	25
	8.80	539.0	2848.6	1992,341,0500	
	17.5	550.5	2844.0	1996,090,0900	
HSH 24-Hour	4.00	557.0	2849.0	1990,345,2300	5
	4.10	548.0	2848.6	1992,106,2300	
	4.04	548.0	2848.6	1996,288,2300	

Note: HSH = Highest, Second-Highest
UTM = Universal Transverse Mercator

^a Based on the CALPUFF model using 1990, 1992, and 1996 surface and upper air meteorological data developed with the CALMET program. UTM coordinates relative to Zone 17.

Table 6-12. Maximum Predicted PM₁₀ Impacts For Comparison to the PSD Class I Increment

Rank and Averaging Time	Concentration ($\mu\text{g}/\text{m}^3$) ^a	Receptor UTM Location (km)		Time Period (Year, Julian Day, Hour Ending)	PSD Class I Increment ($\mu\text{g}/\text{m}^3$)
	Modeled Sources	East	North		
HSH 24-Hour	2.14	542.0	2848.6	1990,268,2300	5
	1.86	545.0	2848.6	1992,044,2300	
	1.89	549.0	2848.6	1996,320,2300	

Note: HSH = Highest, Second-Highest
UTM = Universal Transverse Mercator

^a Based on the CALPUFF model using 1990, 1992, and 1996 surface and upper air meteorological data developed with the CALMET program. UTM coordinates relative to Zone 17.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 IMPACTS DUE TO ASSOCIATED DIRECT GROWTH

7.1.1 INTRODUCTION

Rule 62-212.400(3)(h)(5), F.A.C., states that an application must include information relating to the air quality impacts of, and the nature and extent of all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. This growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the proposed expansion at the Turkey Point Plant. This information is consistent with the EPA Guidance related to this requirement in the *Draft New Source Review Workshop Manual* (EPA, 1990).

In general, there has been minimal growth in the Turkey Point Plant area since 1977. The site is located in southeast Miami-Dade County on Florida's Atlantic coast. Miami-Dade County is surrounded by Monroe County to the south and west, Collier County to the northwest, and Broward to the north. Miami-Dade County is the second largest county in Florida, comprising a 2,430-square mile area. The county has 1,945 square miles of land area.

The Project is being constructed to meet current and projected electric demands. FPL has an obligation to meet this increase in electric demand. Additional growth as a direct result of the additional electric power provided by the Project is not expected.

Construction of the Project will occur over a 24-month period requiring an average of approximately 250 workers during that time. It is anticipated that many of these construction personnel will commute to the Site.

The Project will employ a total of 12 operational workers at Project build-out. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to operate the proposed Project represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated commercial and industrial growth given the location at the existing Turkey Point Plant. The existing commercial and industrial

infrastructure should be adequate to provide any support services that the Project might require and would not increase with the operation of the Project. The addition of the nominal 1,000-MW facility had little effect on the increase or growth in the area.

The following discussion presents general trends in residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in Miami-Dade County. As such, the information presents information available from a variety of sources (i.e., Florida Statistical Abstract, FDEP, etc.) that characterize Miami-Dade County as a whole.

7.1.2 RESIDENTIAL GROWTH

Population and Household Trends

As an indicator of residential growth, the trend in the population and number of household units in Miami-Dade County since 1977 are shown in Figure 7-1. The county experienced a 47-percent increase in population for the years 1977 through 2000. During this period, there was an increase in population of about 719,000. Similarly, the number of households in the county increased by about 244,000, or 46 percent, since 1977.

Growth Associated with the Operation of the Project

Because there will be about 12 workers needed to operate the Project, residential growth due to the Project will be minimal.

7.1.3 COMMERCIAL GROWTH

Retail Trade and Wholesale Trade

As an indicator of commercial growth in Miami-Dade County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure 7-2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell; manufacturers' sales branches and offices that sell products manufactured domestically by their own company; and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

Since 1977, retail trade has increased by about 4,000 establishments and 64,200 employees or 49 and 57 percent, respectively. For the same period, wholesale trade has increased by 5,700 establishments and 34,000 employees, or 148 and 78 percent, respectively.

Labor Force

The trend in the labor force in Miami-Dade County since 1977 is shown in Figure 7-3. The greatest number of persons employed in Miami-Dade County has been in the agriculture, services, and government sectors. Between 1977 and 1999, approximately 441,000 persons were added to the available work force, for an increase of 71 percent.

Tourism

Another indicator of commercial growth in Miami-Dade County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure 7-4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1978 and 2000, there were decreases of 42 and 23 percent in the number of hotels and motels as well as the number of units at those establishments in the county, respectively.

Transportation

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Miami-Dade County is presented in Figure 7-5. The county's main arteries are Interstate 95, the Florida Turnpike, and U.S. Route 1.

Between 1977 and 2001, there was an increase of about 17,900,000 VMT, or 58 percent, on major roadways in the county.

Growth Associated with the Operation of the Project

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of the Project. The workforce needed to operate the proposed Project represents a small fraction of the labor force present in the immediate and surrounding areas.

7.1.4 INDUSTRIAL GROWTH**Manufacturing and Agricultural Industries**

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Miami-Dade County since 1977 is shown in Figure 7-6. As shown, the manufacturing industry experienced an increase of 3,900 employees or 184 percent from 1977 through 2000.

As another indicator of industrial growth, the trend in the number of employees in the agricultural industry in Miami-Dade County since 1977 is also shown in Figure 7-6. As shown, the agricultural industry experienced a decrease 19 percent in employment from 1977 through 1999.

Utilities

Existing power plants in Miami-Dade County include the following:

- FPL's Turkey Point Plant,
- FPL's Cutler Plant, and
- City of Homestead Utility.

Together, these power plants have an electrical nameplate generating capacity of over 2,000 MW.

As an indicator of electrical utility growth, the electrical nameplate generating capacity in Miami-Dade County since 1977 is shown in Figure 7-7. As shown, there has been minimal change in electrical utility growth since 1977.

Growth Associated with the Operation of the Project

Since the PSD baseline date of August 7, 1977, there have not been any major facilities built within a 35-km radius of the Turkey Point Plant Site. There are a limited number of facilities located throughout the 35-km radius area surrounding the site. Based on the locations of nearby air emission

sources (see Tables 6-3 and 6-4), there has not been a concentration of industrial and commercial growth in the vicinity of the Turkey Point Plant Site.

7.1.5 AIR QUALITY DISCUSSION

Air Emissions and Spatial Distribution of Major Facilities

The locations of major air pollutant facilities in Miami-Dade County are presented in Tables 6-3 and 6-4. Based on actual emissions reported for 1999 (latest year of available data) by EPA on its AIRSdata website, total emissions from stationary sources in the county are as follows:

- SO₂: 15,400 TPY
- PM₁₀: 1,980 TPY
- NO_x: 17,900 TPY
- CO: 5,240 TPY
- VOC: 3,950 TPY

Air Emissions from Mobile Sources

The trends in the air emissions of CO, VOC, and NO_x from mobile sources in Miami-Dade County are presented in Figure 7-8. Between 1977 and 2002, there were significant decreases in these emissions. The decrease in CO, VOC, NO_x emissions were about 1,670; 183; and 59 tons per day, respectively, which represent decreases from 1977 emissions of 61, 65, and 29 percent, respectively.

Air Monitoring Data

Since 1977, Miami-Dade County has been classified as attainment or maintenance for all criteria pollutants. Air quality monitoring data have been collected in Miami-Dade County, primarily in the eastern portion of the county. For this evaluation, the air quality monitoring data collected at the monitoring station nearest to the Turkey Point Plant were used to assess air quality trends since 1977.

Air quality monitoring data were based on the following monitoring stations:

- SO₂, CO, and O₃ concentrations – Miami,
- PM₁₀ concentrations – Miami and Homestead, and
- NO₂ concentrations – Miami and Virginia Key.

Data collected from these stations are considered to be generally representative of air quality in Miami-Dade County. Because these monitoring stations are generally located in more industrialized

areas than the Turkey Point Plant, the reported concentrations are likely to be somewhat higher than that experienced at the site.

These data indicate that the maximum air quality concentrations currently measured in the region comply with and are well below the applicable AAQS. These monitoring stations are located in areas where the highest concentrations of a measured pollutant are expected due to the combined effect of emissions from stationary and mobile sources, as well as the effects of meteorology. Therefore, the ambient concentrations in areas not monitored should have pollutant concentrations less than the monitored concentrations from these sites.

In addition, since 1988, PM in the form of PM₁₀ has been collected at the air monitoring stations due to the promulgation of the PM₁₀ AAQS. Prior to 1989, the AAQS for PM was in the form of total suspended particulates (TSP) concentrations, and this form was measured at the stations.

SO₂ Concentrations

The trends in the 3-hour, 24-hour, and annual average SO₂ concentrations measured in Miami-Dade County since 1977 are presented in Figures 7-9 through 7-11, respectively. As shown in these figures, measured SO₂ concentrations have been and continue to be well below the AAQS.

PM₁₀/TSP Concentrations

The trends in the 24-hour and annual average PM₁₀ and TSP concentrations since 1977 are presented in Figures 7-11 and 7-13, respectively. TSP concentrations are presented through 1988 since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked and the PM standard was revised to PM₁₀.

As shown in these figures, measured TSP concentrations were generally below the TSP AAQS. Since 1988 when PM₁₀ concentrations have been measured, the PM₁₀ concentrations have been and continue to be below the AAQS.

NO₂ Concentrations

The trends in the annual average NO₂ concentrations measured at the nearest monitors to the Turkey Point Plant are presented in Figure 7-14. As shown in this figure, measured NO₂ concentrations have been well below the AAQS.

CO Concentrations

The trends in the 1-hour and 8-hour average CO concentrations since 1977 are presented in Figures 7-15 and 7-16, respectively. As shown in these figures, measured CO concentrations have been well below the AAQS.

Ozone Concentrations

The trends in the 1-hour average O₃ concentrations since 1977 are presented in Figure 7-17. The trends in the 8-hour average O₃ concentrations since 1995 are presented in Figure 7-18. As shown in these figures, even in the more urbanized areas of Miami-Dade County, the measured O₃ concentrations have been well below the 1-hour average AAQS and the new 8-hour average AAQS.

Air Quality Associated with the Operation of the Project

The air quality data measured in the region of the Turkey Point Plant indicate that the maximum air quality concentrations are well below and comply with the AAQS. Also, based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the baseline date of August 7, 1977. Because the maximum concentrations for the proposed expansion of the Turkey Point Plant are predicted to be below the significant impact levels, air quality concentrations in the region are expected to remain below and comply with the AAQS when the Project becomes operational.

7.2 IMPACTS ON SOILS, VEGETATION, WILDLIFE AND VISIBILITY

The maximum air quality impacts for the Project predicted in the vicinity of the site were used to assess the Project's potential impacts on nearby soils, vegetation, wildlife, and visibility.

According to the USDA Soil Survey of Dade County (1996), three soils series are found in the vicinity of the Project area: Terra Ceia muck, tidal; Pennsuco marl, tidal; and Urban Land. These soils are summarized from the soil survey descriptions in the follow sections.

7.2.1 TERRA CEIA MUCK, TIDAL

This deep, level, very poorly drained soil is in saltwater swamps and marshes and is subject to tidal flooding. Typically, the soil is muck to a depth of 80 inches or more. The upper 8 inches is very dark brown, and the lower 72 inches or more is black. Under natural conditions, the Terra Ceia soil remains saturated. Fluctuating tides cover the surface twice daily. Permeability is rapid. The pH of

Terra Ceia muck, tidal, ranges from 4.5 to 8.4. The natural vegetation consists mainly of red and black mangrove, with occasional white mangrove in some areas. Because of tidal flooding, this soil is not suited to cropland, citrus, improved pasture, or urban uses.

7.2.2 PENNSUCO MARL, TIDAL

This deep, nearly level, very poorly drained soil is in tidal mangrove swamps near the coast in southeastern Florida and is subject to tidal flooding. Typically, the surface layer is about 51 inches of light gray marl that has a texture of silt loam. Soft, porous limestone bedrock is at a depth of about 51 inches. Under natural conditions, Pennsuco marl soil remains saturated and the water table fluctuates with the tides. The soil is moderately saline or saline. Permeability is moderately slow. Due to the presence of limestone, the pH ranges from 7.9 to 8.4. The natural vegetation is scattered and stunted red mangrove. Because of tidal flooding and salinity, this soil is not suited to cropland, groves, rangeland, improved pasture, or urban uses.

7.2.3 URBAN LAND

This map unit is in areas where more than 85 percent of the surface is covered by shopping centers, parking lots, streets, sidewalks, airports, large buildings, houses, and other structures. The natural soil cannot be observed. The soils in open areas, mostly lawns, vacant lots, playgrounds, and parks, are mainly Udorthents. These soils generally have been altered by land grading and shaping or have been covered with about 18 inches of extremely stony, loamy fill material.

The principal soils found in the Project Area are inundated by tidal waters and contain relatively high organic matter content, which provides high buffering capacity based on their cation exchange capacity and bulk density. The regular flooding of these soils by tidal waters from Biscayne Bay acts to regulate the pH and any change in acidity in the soil would be buffered by this activity. Therefore, these soils would be relatively insensitive to atmospheric inputs.

The emissions that could cause potential impact to soils are SO₂ and NO_x. The primary effect of SO₂ and NO_x deposition and adsorption by soils is the resultant lowering of soil pH. Low soil pH will have an influence on most chemical and biological reactions in the soil including the level and availability of most plant nutrients in the soil. Based on the extremely low SO₂ and NO₂ impacts predicted for the Project and the highly organic, well-buffered nature of the soils, the Project's emissions will not have any significant adverse impact to soils within the Project Area or vicinity.

Vegetative communities in the vicinity of the Project Area are tidal dwarf red mangrove swamps, dominated by red mangrove (*Rhizophora mangle*), with subdominant species including buttonwood (*Conocarpus erectus*), white mangrove (*Laguncularia racemosa*), and occasional black mangrove (*Avicennia germinans*). Approximately 90 percent of the red mangroves within the Project Area are characteristic of the dwarf mangrove community, reduced in size due to higher salinities and reduced tidal flushing, while approximately 10 percent are large individuals located adjacent to a sinuous tidal creek. Additional vegetative species observed within the mangrove community include occasional Brazilian pepper (*Schinus terebinthifolius*), Australian pine (*Casuarina equisetifolia*), tree seaside oxeye (*Borrchia arborescens*), grey nicker (*Caesalpinia bonduc*), groundsel tree (*Baccharis halimifolia*), and cordgrass (*Spartina* sp.).

The Project's impacts on the local air quality are predicted to be less than the significant impact levels for PSD Class II. Since the Project's impacts are predicted to be less than the significant impact levels, no detrimental effects on soils or vegetation should occur in this area due to the Project's operation.

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutants levels.

It is unlikely that the Project's emissions will cause injury or death to wildlife based on a review of the limited literature on air pollutant effects on wildlife. The Project's impacts are predicted to be very low and dispersed over a large area. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the Project's impacts under weather conditions that lead to high concentrations is extremely unlikely.

In addition, no visibility impairment in the Project's vicinity is expected due to the types and quantities of emissions proposed for the Project. The opacity of the proposed exhaust emissions for both simple and combined cycle operation will be 10 percent or less.

7.3 IMPACTS TO PSD CLASS I AREAS

7.3.1 IDENTIFICATION OF AQRVS AND METHODOLOGY

An Air Quality Related Value (AQRV) analysis was conducted to assess the potential risk to AQRVs at the Everglades National Park due to the proposed emissions from the Project. The Everglades National Park is the closest Class I area to the Turkey Point Plant Site, and is located about 21 km west of the Project site.

The AQRVs include visibility freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

The maximum predicted atmospheric concentrations due to the increase in emissions resulting from the proposed Project are presented in Table 7-1. As shown, the predicted increase in impacts is very low for all pollutants considered.

7.3.2 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades National Park are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as CaCO_3).

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Everglades National Park from the Project emissions precludes any significant impact on soils.

7.3.3 IMPACTS TO VEGETATION

In general, the effects of air pollutants on vegetation occur primarily from SO_2 , NO_2 , O_3 , and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

The concentrations of the pollutants, duration of exposure and frequency of exposures influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration, which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

Observed SO₂ effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively. SO₂ gas at elevated levels has long been known to cause injury to plants. Acute SO₂ injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercoastal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO₂ range from 2.5 to 25 µg/m³.

Many studies have been conducted to determine the effects of high-concentration, short-term SO₂ exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO₂ concentrations of 790 to 1,570 µg/m³. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO₂ concentrations of 1,570 to 2,100 µg/m³. Resistant species (injured at concentrations above 2,100 µg/m³ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to $1,300 \mu\text{g}/\text{m}^3$ SO_2 for 8 hours were not visibly damaged. This finding support the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of $920 \mu\text{g}/\text{m}^3$.

Two lichen species indigenous to the park area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to $400 \mu\text{g}/\text{m}^3$ for 6 hours/week for 10 weeks (Hart *et al.*, 1988).

Jack pine seedlings exposed to SO_2 concentrations of 470 to $520 \mu\text{g}/\text{m}^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to $1,310 \mu\text{g}/\text{m}^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

The maximum 3-, 8-, and 24-hour average SO_2 concentrations for the Project are predicted to be 1.76, 0.79, and $0.38 \mu\text{g}/\text{m}^3$, respectively, at the Class I area. The maximum 3-hour average SO_2 concentrations predicted for the Project at the Class I areas are 0.8 percent or less of those that caused damage to the most sensitive lichens. The modeled annual incremental increase in SO_2 adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

Nitrogen Dioxide

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant expansion. This compound can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru *et al.*, 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to $15,000 \mu\text{g}/\text{m}^3$ (Heck and Tingey, 1979). Chronic exposure of

selected plants (some considered NO_2 -sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu\text{g}/\text{m}^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to the Project are predicted to be 12.2, 6.6, and 3.3 $\mu\text{g}/\text{m}^3$, respectively, at the Class I area. These concentrations are approximately 0.02 to 0.3 percent of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the maximum annual NO_2 concentration due to the Project is predicted to be 0.073 $\mu\text{g}/\text{m}^3$ at the Class I area, which is 0.002 to 0.004 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 $\mu\text{g}/\text{m}^3$ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 $\mu\text{g}/\text{m}^3$ did not appear to be injurious to the tested plants.

The maximum 8-hour PM concentration due to the Project is predicted to be 1.04 $\mu\text{g}/\text{m}^3$ at the Class I area. This concentration is approximately 0.28 to 0.50 percent of the values that affected plant foliage. As a result, no significant effects to vegetative AQRVs are expected from the Project's emissions.

Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only

occurs at extremely high concentrations of CO. Pollok *et al.* (1989) reported that exposure to CO:O₂ ratio of 25 (equivalent to an ambient CO concentration of $6.85 \times 10^6 \mu\text{g}/\text{m}^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik *et al.* (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at CO:O₂ ratios of 2.5 (equivalent to an ambient CO concentration of $6.85 \times 10^5 \mu\text{g}/\text{m}^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

The maximum 1-hour average concentration due to the Project is $18.1 \mu\text{g}/\text{m}^3$ in the Class I area which is less than 0.001 percent of the minimum value that caused inhibition in laboratory studies. The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentration of $0.20 \mu\text{g}/\text{m}^3$ reflects more realistic, yet conservative, CO level for the Class I areas. This maximum concentration is predicted to be less than 0.00003 percent of the value that caused cytochrome *c* oxidase inhibition.

Sulfuric Acid Mist

Acidic precipitation or acid rain is coupled to SO₂ emissions mainly formed during the burning of fossil fuels. This pollutant is oxidized in the atmosphere and dissolves in rain forming sulfuric acid mist which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, sulfuric acid mist has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton *et al.*, 1950).

No significant adverse effects on vegetation are expected from the Project's emissions because SO₂ concentrations, which lead directly to the formation of sulfuric acid mist concentrations, are predicted to be well below levels which have been documented as negatively affecting vegetation. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentrations of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well published and publicized, detrimental effects of acid rain on Florida vegetation are lacking documentation.

Summary

In summary, the phytotoxic effects on the Everglades National Park from proposed Project's emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.3.4 IMPACTS TO WILDLIFE

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 7-4.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National Ambient Air Quality Standards. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

For impacts on wildlife, the lowest threshold values of SO₂, NO_x, and particulates that are reported to cause physiological changes are shown in Table 7-4. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area.

No significant effects on wildlife AQRVs from SO₂, NO_x, and particulates are expected. These results are considered indications of the risk of other air pollutant emissions predicted from the Project, which is also considered to be negligible.

7.4 IMPACTS ON VISIBILITY

7.4.1 INTRODUCTION

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Visibility can take the form of plume blight for nearby areas (i.e., distances within 50 km) or regional haze for long distances (i.e., distances beyond 50 km).

Sources of air pollution can cause visible plumes if emissions of PM₁₀ and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the Everglades National Park. Because the nearest distance of the Turkey Point Plant to the Everglades National Park is about 21 km, the change in visibility is analyzed as plume blight within 50 km. However, the Everglades National Park also extends beyond 50 km from the Turkey Point Plant. As a result, the change in visibility for the Project is also analyzed as regional haze.

Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and FLM of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in guidelines required by the 1977 Clean Air Act Amendments and are contained in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report; and
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report*, USFS, NPS, USFWS (December, 2000), referred to as the FLAG document.

The methods and assumptions recommended in these documents were used to assess visibility impairment due to the Project.

Visibility Analysis within 50 km of the Everglades National Park

Methodology—The analysis to determine the potential adverse plume visibility effects in the Everglades National Park was based on recommendations in the FLAG document using the screening approach suggested in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1992). EPA has computerized this approach in a program called the VISCREEN model. The VISCREEN model is currently recommended for use by the EPA to assess visual plume impacts in regulatory applications. The VISCREEN model can be used to calculate potential plume impact of specific pollutant emissions for specific transport and meteorological dispersion conditions. The model can be applied in two successive levels of screening (i.e., referred to as Levels 1 and 2) without the need for extensive source, meteorological, or pollutant input. If the screening calculations demonstrate that, during worst-case meteorological conditions a plume is imperceptible or, if perceptible, is not likely to be considered objectionable ("adverse" or "significant" in the language of the EPA PSD and visibility regulations), further analysis of plume visual impact would not be required as part of the air quality review of the source. However, if the screening analyses demonstrate that the criteria are exceeded, plume visual impacts cannot be ruled out, and more detailed analyses to ascertain the magnitude, frequency, location, and timing of plume visual impacts would be required.

The Level 1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts that would be larger than those calculated with more realistic input and modeling assumptions). This analysis assumes worst-case meteorological conditions of stable stability (Pasquill-Gifford stability Class F) and a 1 m/s wind speed persisting for 12 hours in one direction towards a PSD Class I area. The input required for the Level 1 analysis is limited to the following parameters:

- Emission rates of PM₁₀ and NO_x;
- Distance between the emission source and (a) the observer; (b) the closest Class I area boundary; and (c) the most distant Class I area boundary;
- Background visual range appropriate for the region in which the Class I area is located; and
- If available, emission rates of NO₂, soot, and primary sulfate.

Visibility impacts are then determined for two parameters:

- Contrast of a plume against a viewing background such as the sky or a terrain feature, and
- Perceptibility of a plume on the basis of the color difference between the plume and the viewing background (Delta E).

Results are provided by the model for several scenarios based on the background view, the viewing angle, visibility improvement due to plumes located both inside and outside the Class I area, and the sun angle. The critical values for contrast and Delta E are 0.05 and 2.00, respectively. If these levels are not exceeded by the proposed source, the source is considered to pass the Level 1 visibility analysis, and the source will not have a significant impact on the Class I area.

Results of Level 1 Analysis--The input parameters and results of the Level 1 analysis for the Project firing natural gas and light oil are presented in Figure 7-19. As shown, the Project will emit PM_{10} , NO_x , and primary SO_4 (as sulfuric acid mist). The maximum short-term average emission rates used in the analysis, which are presented in Section 2.0 and Appendix A, are based on the CTs operating at baseload conditions for natural gas with duct firing and for light oil at an air inlet temperature of 35°F. Primary NO_2 and soot are not emitted in significant quantities by natural gas-fired combustion sources; therefore, these emissions were set to zero.

The terrain between the Turkey Point Project Site and PSD Class I area and within the Class I area can be considered as generally flat. With no terrain feature that can be used as a viewing background, the visibility impacts were determined using the sky as the only viewing background. It should also be noted that these critical visual impacts are estimated for locations inside of the Class I area. Since no integral vistas have been identified for the NP, this evaluation did not evaluate vistas located outside the Class I area.

From the FLAG report, the background visual range for the Everglades National Park was assumed to be 178 km.

Other parameters input to the model were based upon default values given in the Workbook and incorporated into the computer model.

As shown in these figures, the Project's emissions due to firing both fuels are calculated to exceed the Level 1 visibility screening criteria at the Class I area. Because results from the Level 1 screening analysis exceed the visibility criteria, a Level 2 screening analysis was performed. One of the main differences in input between the Level 1 and Level 2 analyses is the meteorology assumed for plume transport and dispersion patterns.

Results of Level 2 Analysis--The Level 2 screening analysis is designed to account for more realistic occurrences of meteorological conditions that would transport the plumes of the proposed units towards the Class I area. In this analysis, an assessment of the frequency of the wind direction, wind speed, and atmospheric stability classes is made to determine the frequency of conditions that are most likely to cause a potentially adverse plume visual impact. If the Level 1 default parameters are selected for addressing visual plume impacts, the VISCREEN model assigns an appropriate estimate of particle size and density for the emitted and background atmosphere particulate and worst-case plume dispersion conditions. For this analysis, the particle size and density for the emission sources were not changed.

The first step in the analysis is to construct a table that shows worst-case dispersion conditions ranked in order of decreasing severity and the frequency of occurrence of these conditions associated with the wind direction that could transport emissions toward the Class I area. Dispersion conditions are ranked by evaluating the product of the horizontal dispersion parameter (called sigma y) times the vertical dispersion parameter (called sigma z) times the wind speed. Sigma y and sigma z account for the amount of plume spreading or dispersion that will occur as a plume travels away from a source for a given stability class. The dispersion conditions are then ranked in ascending order of the value of the dispersion product term (i.e., sigma y times sigma z times the wind speed).

For the Level 2 analysis, it is assumed that steady-state plume conditions are unlikely to persist for more than 12 hours. Thus, if a transit time of more than 12 hours is required to transport a plume parcel from the emission source to a Class I area for a given dispersion condition, it is assumed that the plume material is more dispersed than a standard Gaussian plume model would predict. This enhanced dilution would result from daytime convective mixing and wind direction and speed changes.

To obtain the worst-case meteorological conditions, it is necessary to determine the dispersion conditions (i.e., a given wind speed and stability class associated with the wind direction that would transport emissions toward the Class I area) that have a dispersion product term with a cumulative probability of 1 percent. Thus, the dispersion condition is selected to address potential plume visual impacts such that the sum of all frequencies of occurrence worse than this condition totals 1 percent (i.e., about 4 days per year). The 1-percentile meteorology is assumed to be worst-case plume visual impacts when the probability of worst-case meteorology conditions is coupled with the probability of

other factors being ideal for maximizing plume visual impacts. Dispersion conditions associated with transport times of more than 12 hours are not considered in this cumulative frequency.

For this study, the surface meteorological data from the NWS station in Miami from 1987 to 1991 were used to generate a frequency distribution of wind direction, wind speed, and stability occurrences based on the standardized stability array (STAR) program used for many air dispersion model applications. The STAR program generates frequencies using 16 wind direction classes with each class covering a 22.5-degree sector, 6 windspeed classes, and 6 stability classes. It should be noted that these data were used to address air quality impacts from the Project as presented in Section 6.0.

The PSD Class I area of the Everglades National Park is located to the southwest through west-northwest of the Turkey Point Project Site, with the closest distances of 20.8 km to the southwest and 24.1 km to the west. Therefore, the frequencies associated with winds that would blow from the Project to the Class I area were included in the analysis (i.e., northeast through east-southeast). The highest frequency from the northwest and east-northeast was used in the cumulative frequency to determine the worst-case meteorology for impacts at the closest distance of 20 km. The highest frequency from the east and east-southeast was used to determine the worst-case meteorology for impacts to the west at a distance of 24.1 km.

As an additional conservative approach used in the method recommended by the Workbook, the frequencies were classified into four 6-hour periods: 1 a.m. to 6 a.m.; 7 a.m. to 12 p.m.; 1 p.m. to 6 p.m.; and 7 p.m. to 12 a.m. In effect, the criteria of 1 percent are applied to each 6-hour period, allowing only 1 day to exceed the criteria per period (instead of using the frequencies for an entire day summed over the year). However, since the approach is based on viewing the plume during the day when the sun is either in front or back of the observer, the frequencies are presented only for the 6-hour periods during the daytime from 7 a.m. to 12 p.m. and 1 p.m. to 6 p.m.

This analysis is presented in Table 7-5, which shows the dispersion product term, transport time to the nearest part of the Class I area (i.e., distance of 20.8 km), and the frequency associated with each wind direction. As indicated in Table 7-5, all of the meteorological conditions considered in the analysis could be transported to the Class I area in less than 12 hours. As a result, these conditions

were all included in determining the worst-case meteorology using the cumulative probability of 1 percent.

During the daytime period, the weather condition for the northeast and east-northeast wind directions produced a cumulative frequency of 1 percent or more (neutral stability and wind speed of 4.4 m/s). This weather condition was used to assess the potential visual plume impacts from the Project at the closest distance of 20.8 km to the southwest.

For impacts to the west of the Turkey Point Project Site, slightly stable stability and windspeed of 2.6 m/s from the east wind direction was used to assess the potential visual impacts from the Project.

The results of the visual plume impact analysis using the Level 2 meteorological condition for the Project firing natural gas and light oil are shown in Figure 7-6. As shown, the Project's values of Delta E and contrast for firing natural gas are predicted to be less than the screening criteria of 2.00 and 0.05, respectively. For light oil firing, which will be limited to a maximum of 500 hours per year for each combustion turbine, the Project values of Delta E and contrast were also predicted to be less than the screening criteria in directions to the southwest of the Project. However, in directions to the west, the predicted Project values were less than contrast criteria of 0.05 but slightly greater than the Delta E screening criteria of 2.00.

These results were produced for worst-case meteorology allowing only 1 day to exceed the criteria per period based on the hours that occurred in a year during that 6-hour period. If the frequencies for each period were based on all hours that occurred over the entire year, it is likely the worst-case meteorology would result in lower Project impacts. In addition, higher impacts for the Project are produced using the reconstructed natural background visual range of 178 km obtained from the FLAG document. If the value for background visual range recommended in the VISCREEN workbook was used (i.e., 40 km), the Project impacts for oil-firing would be less than the Delta E and contrast screening criteria. Lastly, these impacts are based on four combustion turbines operating simultaneously at baseload conditions at an ambient temperature of 35 °F and firing fuel oil. As a result, it is highly unlikely that the worst-case emissions will occur with the worst-case meteorology, particularly since each combustion turbine will be limited to firing oil for 500 hours or less per year, to produce impacts greater than the screening criteria at the Class I area located to the west of the Project.

Therefore, given that the Project will be firing primarily natural gas and that there is a low probability of worst-case meteorology occurring with worst-case emissions when the Project is firing oil, the pollutant emissions from the Project firing natural gas or light oil are highly unlikely to cause adverse visibility impairment in the Everglades National Park.

Visibility Analysis at 50 km and More From the Everglades National Park

Methodology—Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

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

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

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed Project. The criteria to determine if the Project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix C) and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. Daily background extinction coefficients are calculated on a hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse mega meter (Mm^{-1}). CALPOST then predicts the percent extinction change for each day of the year.

Results—The results of the refined regional haze analysis are presented in Table 7-7. The results indicate that the proposed Project's maximum predicted impact on visibility at the Everglades National Park is 4.08 percent for the combined cycle operation on natural gas. This value is below the FLM's screening threshold of 5 percent change. Therefore, when firing natural gas, the Project is not expected to have an adverse impact on the existing regional haze in the Everglades National Park.

When firing light oil, the Project's maximum predicted impact on visibility is 7.1 percent. There were three other periods that were above the 5-percent threshold ranging from 5.01 to 6.39 for an average of about 1 day per year over the 3-year period. Given that the Project is seeking approval to fire light oil for less than 21 days per year, there is a very low probability that the 5-percent threshold will be exceeded when firing light oil during the periods of worst-case meteorology. Therefore, the Project is not expected to have an adverse impact on regional haze in the Everglades National Park.

7.4.2 SULFUR AND NITROGEN DEPOSITION

General Methods

As part of the AQRV analyses, total nitrogen (N) and sulfur (S) deposition rates were predicted at the Everglades National Park Class I area. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x , dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

For S deposition, the species include:

- SO_2 , wet and dry deposition; and
- SO_4 , wet and dry deposition.

The CALPUFF model produces results in units of $\mu\text{g}/\text{m}^2/\text{s}$. The modeled deposition rates are then converted to N or S deposition in kg/ha respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II report Section 3.3).

Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition of $0.01 \text{ kg}/\text{ha}/\text{yr}$ were provided by the U.S. Fish and Wildlife Service (January 2002). A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The maximum N and S depositions predicted for the Project are, therefore, compared to these DAT or significant impact levels.

Results

The maximum predicted N and S depositions predicted for the Project in the PSD Class I area of the Everglades National Park are summarized in Table 7-8. The maximum N and S deposition rates for the Project are predicted to be 0.014 and $0.023 \text{ kg}/\text{ha}/\text{yr}$, respectively. These maximum deposition rates are above the significant impact levels for N and S of $0.01 \text{ kg}/\text{ha}/\text{yr}$. Although, the Project's impacts are predicted to be above the significant impact levels for N and S deposition at the Class I area, the soils and vegetation are not sensitive to the very low deposition rates predicted for the Project.

The dominant soils of the Everglades National Park include organic histosols with extremely high buffering capacities and sandy entisols overlying limestone, which provide a buffer to acidic inputs. These soils are resistant to acidic atmospheric inputs. The averaging buffering capacity of histosols is 765,000 equivalents/hectare (eq/ha) (FADS, 1986). As acid inputs (e.g., HNO_3^{-1} and $\text{H}_2\text{SO}_4^{-2}$), the maximum predicted deposition rates of $0.014 \text{ kg}/\text{ha}/\text{yr}$ for nitrogen and $0.023 \text{ kg}/\text{ha}/\text{yr}$ for sulfur, are $1.1 \text{ eq}/\text{ha}/\text{yr}$ and $1.4 \text{ eq}/\text{ha}/\text{yr}$. These deposition rates are extremely small compared to the buffering capacity of the soils in the Everglades National Park. These deposition rates are also small compared to the observed sulfur and nitrogen deposition obtained from the Florida Acid Deposition Study (FADS). Measurements taken near the northern boundary of the Everglade National Park (near U.S Highway 41 and the boundary of Miami-Dade and Monroe Counties) found wet and dry deposition rates of 243 and 306 $\text{eq}/\text{ha}/\text{yr}$ over a three year period (FADS, 1986). In addition, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as CaCO_3). The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the

Everglades National Park from the Project emissions precludes any significant impact on soils. Similarly, the total annual sulfur and nitrogen deposition rates as a result of the Project at the Everglades National Park are not expected to alter soil and/or groundwater pH that may result in adverse effects on vegetation. As presented in Section 7.3.3, the phytotoxic effects on the Everglades National Park from proposed Project's emissions are expected to be minimal.

Table 7-1. Summary of Maximum Pollutant Concentrations Predicted for the Project for the AQRV Analysis,
PSD Class I Area of the Everglades National Park

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m ³)		
		Natural Gas	Fuel Oil	Maximum
SO ₂	Annual	0.037	0.0062	0.037
	24-Hour	0.38	0.068	0.38
	8-Hour	0.79	0.13	0.79
	3-Hour	1.76	0.26	1.76
	1-Hour	3.33	0.48	3.33
PM ₁₀	Annual	0.042	0.048	0.043
	24-Hour	0.43	0.50	0.50
	8-Hour	0.91	1.04	1.04
	3-Hour	2.07	2.11	2.11
	1-Hour	3.79	4.09	4.09
NO ₂	Annual	0.068	0.16	0.073
	24-Hour	0.70	1.74	1.74
	8-Hour	1.41	3.35	3.35
	3-Hour	3.11	6.64	6.64
	1-Hour	6.00	12.2	12.2
CO	Annual	0.20	0.14	0.20
	24-Hour	2.05	1.49	2.05
	8-Hour	4.29	2.87	4.29
	3-Hour	9.57	5.69	9.57
	1-Hour	18.1	10.4	18.1

Note: NM = not modeled.

^a Maximum annual average concentration are based on prorating the maximum impacts for each operation by the following maximum number of hours requested for that operation:

Pollutant	Natural Gas	Fuel Oil	Total
SO ₂	8,760	0	8,760
PM ₁₀	8,260	500	8,760
NO ₂	8,260	500	8,760
CO	8,760	0	8,760

Table 7-2. SO₂ Effects Levels for Various Plant Species

Plant Species	Observed Effect Level ($\mu\text{g}/\text{m}^3$)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart <i>et al.</i> , 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 7-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO₂ Exposures^a

Sensitivity Grouping	SO ₂ Concentration		Plants
	1-Hour	3-Hour	
Sensitive	1,310 - 2,620 µG/m ³ (0.5 - 1.0 ppm)	790 - 1,570 µG/m ³ (0.3 - 0.6 ppm)	Ragweeds
			Legumes
			Blackberry
			Southern pines
			Red and black oaks
			White ash
			Sumacs
Intermediate	2,620 - 5,240 µG/m ³ (1.0 - 2.0 ppm)	1,570 - 2,100 µG/m ³ (0.6 - 0.8 ppm)	Maples
			Locust
			Sweetgum
			Cherry
			Elms
			Tuliptree
			Many crop and garden species
Resistant	>5,240 µG/m ³ (>2.0 ppm)	>2,100 µG/m ³ (>0.8 ppm)	White oaks
			Potato
			Upland cotton
			Corn
			Dogwood
			Peach

^a Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 7-4. Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu\text{g}/\text{m}^3$)	Exposure
Sulfur Dioxide ^a	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide ^{b,c}	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates ^a	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 NiCl_2	2 hours

Sources: ^a Newman and Schreiber, 1988.^b Gardner and Graham, 1976.^c Trzeciak et al., 1977.

Table 7-5. Plume Visual Impact Analysis Using the VISCREEN Model - Screening Level 2,
Identification of Realistic Worst-Case Meteorological Conditions

		Dispersion Conditions				Transport Time to Class I Area (hours) ^a	Time Period			
Stability		Wind Speed (m/s)	Dispersion Parameter		Sigma Y x Sigma Z x Wind Speed (m ³ /s)		7 a.m. to 12 p.m.		1 p.m. to 6 p.m.	
Category	Name		Horizontal (Sigma Y (m))	Vertical (Sigma Z (m))			f ^b	cf ^b	f ^b	cf ^b
<u>Northeast Wind Direction</u>										
F	Moderately Stable	0.8	518.6	61.1	25,337	9.7	0.04	0.04	0.04	0.04
E	Slightly Stable	0.8	778.8	110.9	69,112	9.7	0.00	0.04	0.00	0.04
F	Moderately Stable	2.6	518.6	61.1	82,345	3.0	0.09	0.13	0.01	0.05
F	Moderately Stable	4.4	518.6	61.1	139,352	1.8	0.00	0.13	0.00	0.05
D	Neutral	0.8	1040.1	204.2	169,868	9.7	0.01	0.14	0.01	0.05
E	Slightly Stable	2.6	778.8	110.9	224,613	3.0	0.04	0.17	0.10	0.16
E	Slightly Stable	4.4	778.8	110.9	380,114	1.8	0.03	0.20	0.26	0.41
D	Neutral	2.6	1040.1	204.2	552,072	3.0	0.22	0.42	0.07	0.48
D	Neutral	4.4	1040.1	204.2	934,276	1.8	0.61	1.03	1.06	1.54
<u>East-northeast Wind Direction</u>										
F	Moderately Stable	0.8	518.6	61.1	25,337	9.7	0.02	0.02	0.00	0.00
E	Slightly Stable	0.8	778.8	110.9	69,112	9.7	0.00	0.02	0.00	0.00
F	Moderately Stable	2.6	518.6	61.1	82,345	3.0	0.08	0.10	0.09	0.09
F	Moderately Stable	4.4	518.6	61.1	139,352	1.8	0.00	0.10	0.00	0.09
D	Neutral	0.8	1040.1	204.2	169,868	9.7	0.02	0.12	0.02	0.11
E	Slightly Stable	2.6	778.8	110.9	224,613	3.0	0.05	0.17	0.16	0.26
E	Slightly Stable	4.4	778.8	110.9	380,114	1.8	0.09	0.26	0.47	0.74
D	Neutral	2.6	1040.1	204.2	552,072	3.0	0.20	0.47	0.11	0.85
D	Neutral	4.4	1040.1	204.2	934,276	1.8	1.08	1.54	1.62	2.47

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Table 7-5. Plume Visual Impact Analysis Using the VISCSCREEN Model - Screening Level 2,
Identification of Realistic Worst-Case Meteorological Conditions

		Dispersion Conditions				Transport Time to Class I Area (hours) ^a	Time Period			
Stability		Wind Speed (m/s)	Dispersion Parameter		Sigma Y x Sigma Z x Wind Speed (m ³ /s)		7 a.m. to 12 p.m.		1 p.m. to 6 p.m.	
Category	Name		Horizontal (Sigma Y (m))	Vertical (Sigma Z (m))			f ^b	cf ^b	f ^b	cf ^b
<u>East Wind Direction</u>										
F	Moderately Stable	0.8	518.6	61.1	25,337	9.7	0.05	0.05	0.05	0.05
E	Slightly Stable	0.8	778.8	110.9	69,112	9.7	0.00	0.05	0.00	0.05
F	Moderately Stable	2.6	518.6	61.1	82,345	3.0	0.15	0.19	0.14	0.18
F	Moderately Stable	4.4	518.6	61.1	139,352	1.8	0.00	0.19	0.00	0.18
D	Neutral	0.8	1040.1	204.2	169,868	9.7	0.00	0.19	0.00	0.18
E	Slightly Stable	2.6	778.8	110.9	224,613	3.0	0.16	0.36	0.15	0.33
E	Slightly Stable	4.4	778.8	110.9	380,114	1.8	0.47	0.82	0.85	1.18
D	Neutral	2.6	1040.1	204.2	552,072	3.0	0.29	1.11	0.17	1.35
D	Neutral	4.4	1040.1	204.2	934,276	1.8	2.37	3.49	3.12	4.47
<u>East-southeast Wind Direction</u>										
F	Moderately Stable	0.8	518.6	61.1	25,337	9.7	0.05	0.05	0.00	0.00
E	Slightly Stable	0.8	778.8	110.9	69,112	9.7	0.00	0.05	0.00	0.00
F	Moderately Stable	2.6	518.6	61.1	82,345	3.0	0.09	0.14	0.03	0.03
F	Moderately Stable	4.4	518.6	61.1	139,352	1.8	0.00	0.14	0.00	0.03
D	Neutral	0.8	1040.1	204.2	169,868	9.7	0.02	0.16	0.00	0.03
E	Slightly Stable	2.6	778.8	110.9	224,613	3.0	0.07	0.23	0.04	0.06
E	Slightly Stable	4.4	778.8	110.9	380,114	1.8	0.24	0.47	0.36	0.42
D	Neutral	2.6	1040.1	204.2	552,072	3.0	0.20	0.67	0.20	0.62
D	Neutral	4.4	1040.1	204.2	934,276	1.8	1.29	1.95	1.52	2.14

^a Based on proposed source located approximately 20.8 km from closest boundary of PSD Class I area of the Everglades NP.^b f= frequency for given meteorological condition; cf= cumulative frequency up to and including condition.^c Based on surface meteorological data for 1987 to 1991 from the National Weather Service (NWS) station at the Miami International Airport.

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Table 7-6. VISCREEN Results for Screening Levels 1 and 2 at the PSD Class I Area of the Everglades National Park

Meteorological Condition ^a			Closest Distance to PSD Class I Area Southwest Direction, 20.8 km				Closest Distance to the PSD Class I Area West Direction, 24.1 km			
			Natural Gas		Fuel Oil		Natural Gas		Fuel Oil	
Stability	Stability Class	Wind Speed (m/s)	Delta E	Contrast	Delta E	Contrast	Delta E	Contrast	Delta E	Contrast
Screening Level 1- Worst Case										
Moderately Stable	F	1.0	12.1	0.24	16.8	0.199	11.2	0.215	15.5	0.181
Screening Level 2- More Realistic Case										
Slightly Stable ^b	E	4.4	NA	NA	NA	NA	1.6	0.029	2.2	0.025
Neutral ^c	D	4.4	0.9	0.016	1.2	0.014	NA	NA	NA	NA
SCREENING CRITERIA			2.0	0.05	2.0	0.05	2.0	0.05	2.0	0.05

NA= not applicable

^a Background visual range set to 178 km based on data from the FLAG Report (December 2000).^b Screening Level 2 condition used to assess plume blight for project based on 1% occurrence of worst-case meteorology from the east and east-southeast wind directions.^c Screening Level 2 condition used to assess plume blight for project based on 1% occurrence of worst-case meteorology from the northeast and east-northeast wind directions.

Table 7-7. Maximum 24-hour Average Visibility Impairment Predicted for the Project
at the PSD Class I Area of the Everglades National Park

Operation	Rank	Visibility Impairment (%) ^a	Receptor UTM Location (km)		Time Period (Month/Day/Year)	Number of Visibility Impairment Occurrences > 5/10 % Criteria
			East	North		
Natural Gas- Firing Combined Cycle	Highest	3.75	522.7	2790.8	12/16/1990	0/0
	Highest	4.02	520.6	2831.4	7/22/1992	0/0
	Highest	3.88	541.5	2770.6	11/21/1996	0/0
Fuel Oil- Firing Combined Cycle	Highest	5.01	546.1	2768.2	12/24/1990	1/0
	Highest	5.26	520.9	2832.2	7/22/1992	1/0
	Highest	7.10	457.0	2863.2	11/2/1996	2/0
	2nd Highest	6.39	546.1	2768.2	2/11/1996	

Note: UTM = Universal Transverse Mercator

^a Based on the CALPUFF model using 1990, 1992, and 1996 surface and upper air meteorological data developed with the CALMET program. UTM coordinates relative to Zone 17.
Maximum relative humidity set to 95%.

Table 7-8. Maximum Annual Sulfur and Nitrogen Deposition Predicted for the Project
at the PSD Class I Area of the Everglades National Park

Species	Total Deposition (Wet & Dry)		Receptor UTM Location (km)		Year	Deposition Analysis Threshold ^b (kg/ha/yr)
	(g/m ² /s)	(kg/ha/yr) ^a	East	North		
Sulfur (S) Deposition ^c	5.65E-11	0.0178	544.1	2,820.0	1990	0.01
	5.96E-11	0.0188	544.1	2,820.0	1992	
	7.39E-11	0.0233	544.1	2,820.0	1996	
Nitrogen (N) Deposition ^d	3.73E-11	0.0117	544.1	2,820.0	1990	0.01
	3.88E-11	0.0122	544.1	2,820.0	1992	
	4.27E-11	0.0135	544.1	2,820.0	1996	

^a Conversion factor is used to convert g/m²/s to kg/hectare (ha)/yr with the following units:

$$\begin{array}{lcl}
 \text{g/m}^2/\text{s} \times & & 0.001 \text{ kg/g} \\
 \times & & 10,000 \text{ m}^2/\text{hectare} \\
 \times & & 3,600 \text{ sec/hr} \\
 \times & & 8,760 \text{ hr/yr} = \text{kg/ha/yr} \\
 \text{or} & & \\
 \text{g/m}^2/\text{s} \times & & 3.154\text{E}+08 = \text{kg/ha/yr}
 \end{array}$$

^b Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition provided by the U.S. Fish and Wildlife Service, January 2002.
A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant.

^c Based on each CT firing natural gas for 8,760 hours (with duct firing for 2,880 hours).

^d Based on each CT firing natural gas for 8,260 hours (with duct firing for 2,880 hours) and firing fuel oil for 500 hours.

Figure 7-1. Population and Household Unit Trends in Miami-Dade County

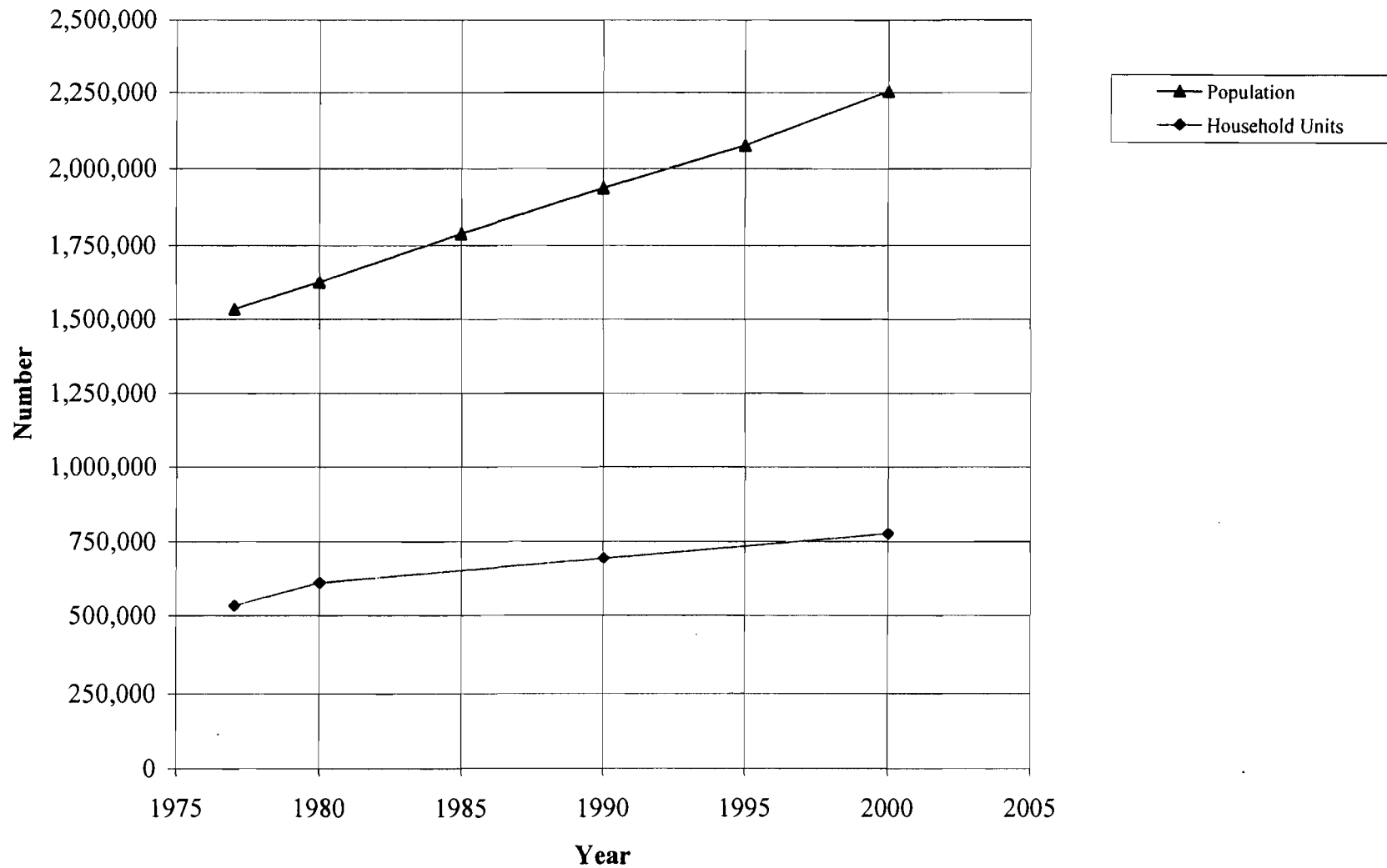


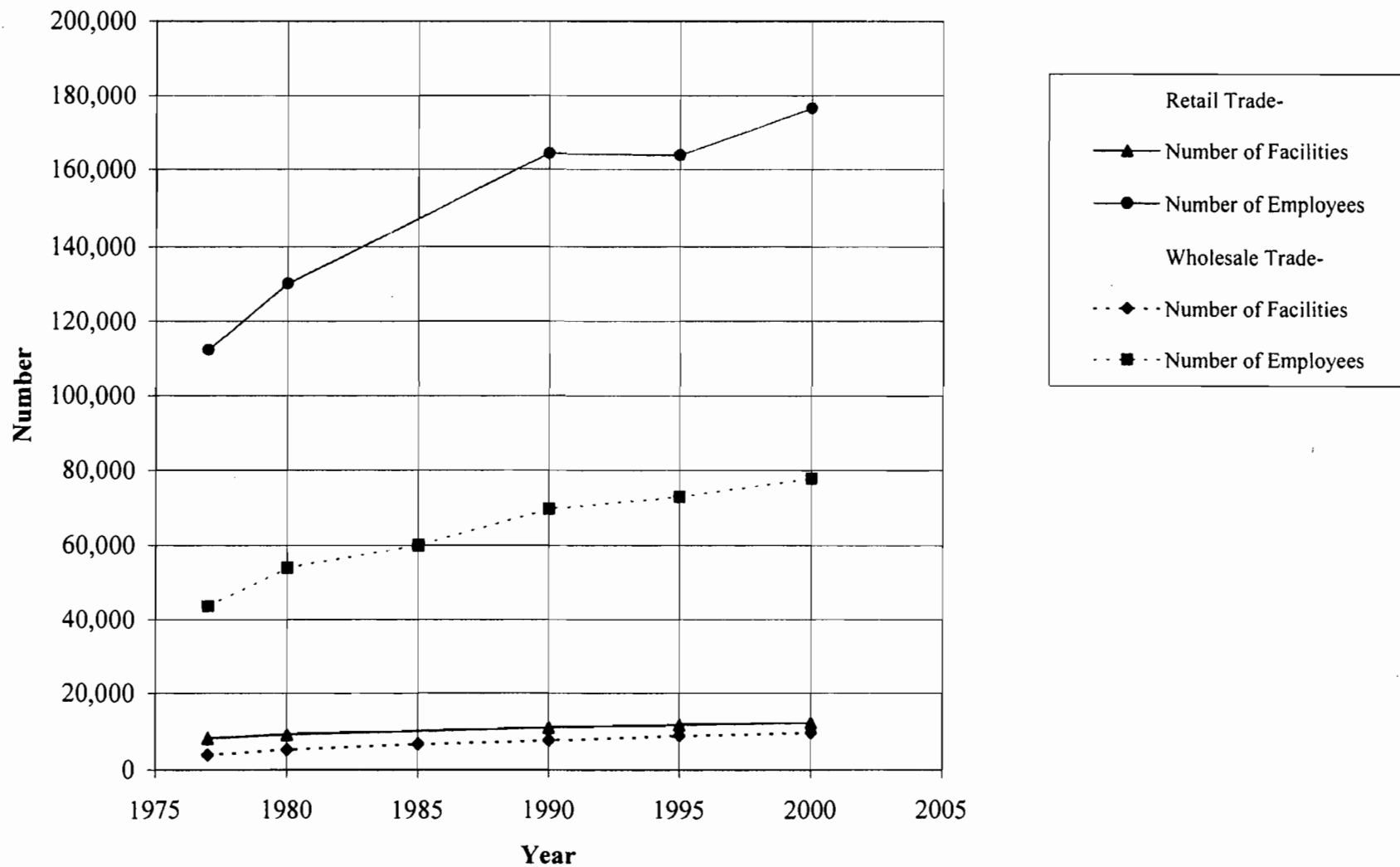
Figure 7-2. Retail and Wholesale Trade Trends in Miami-Dade County

Figure 7-3. Labor Force Trend in Miami-Dade County

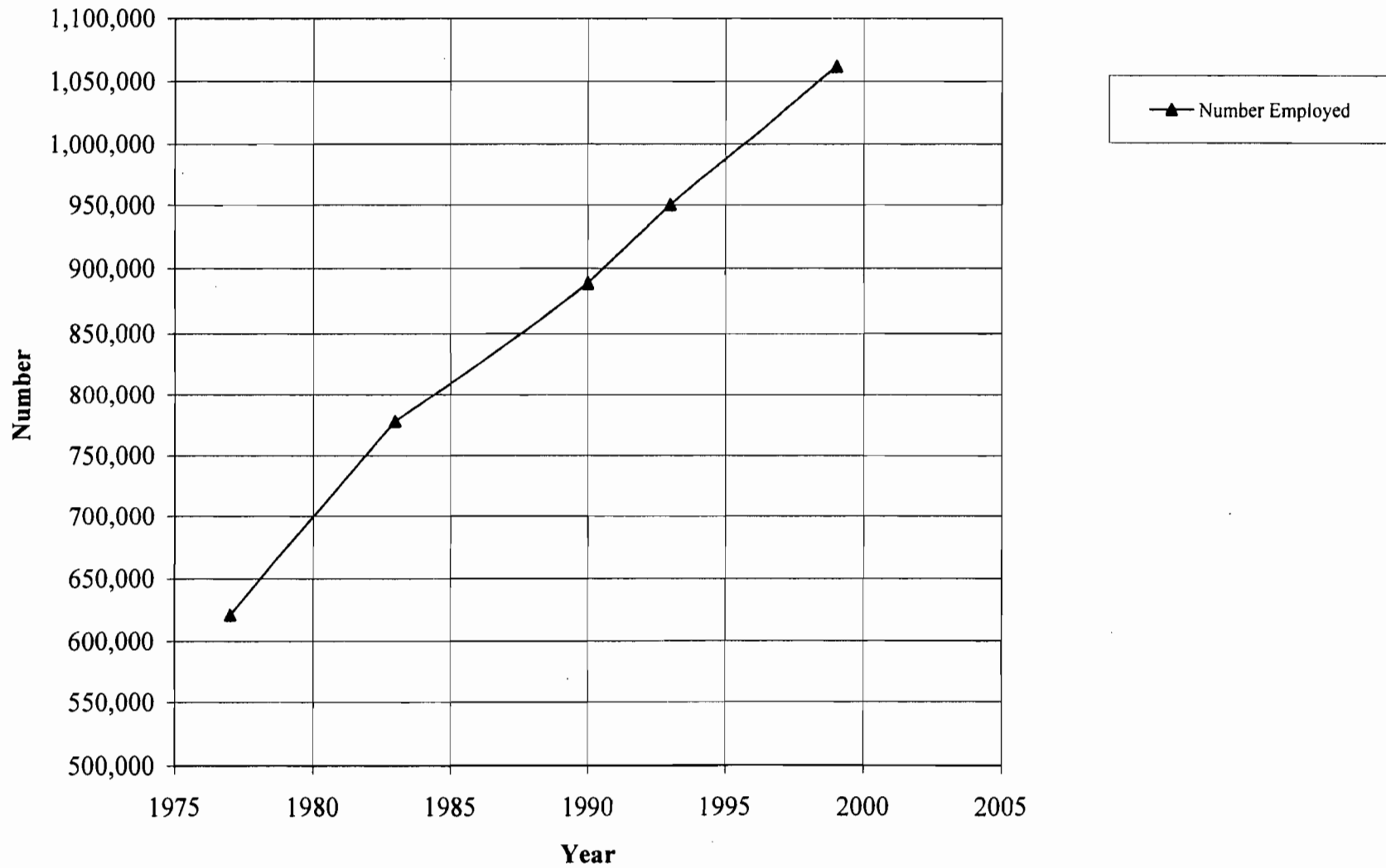


Figure 7-4. Hotel and Motel Trend in Miami-Dade County

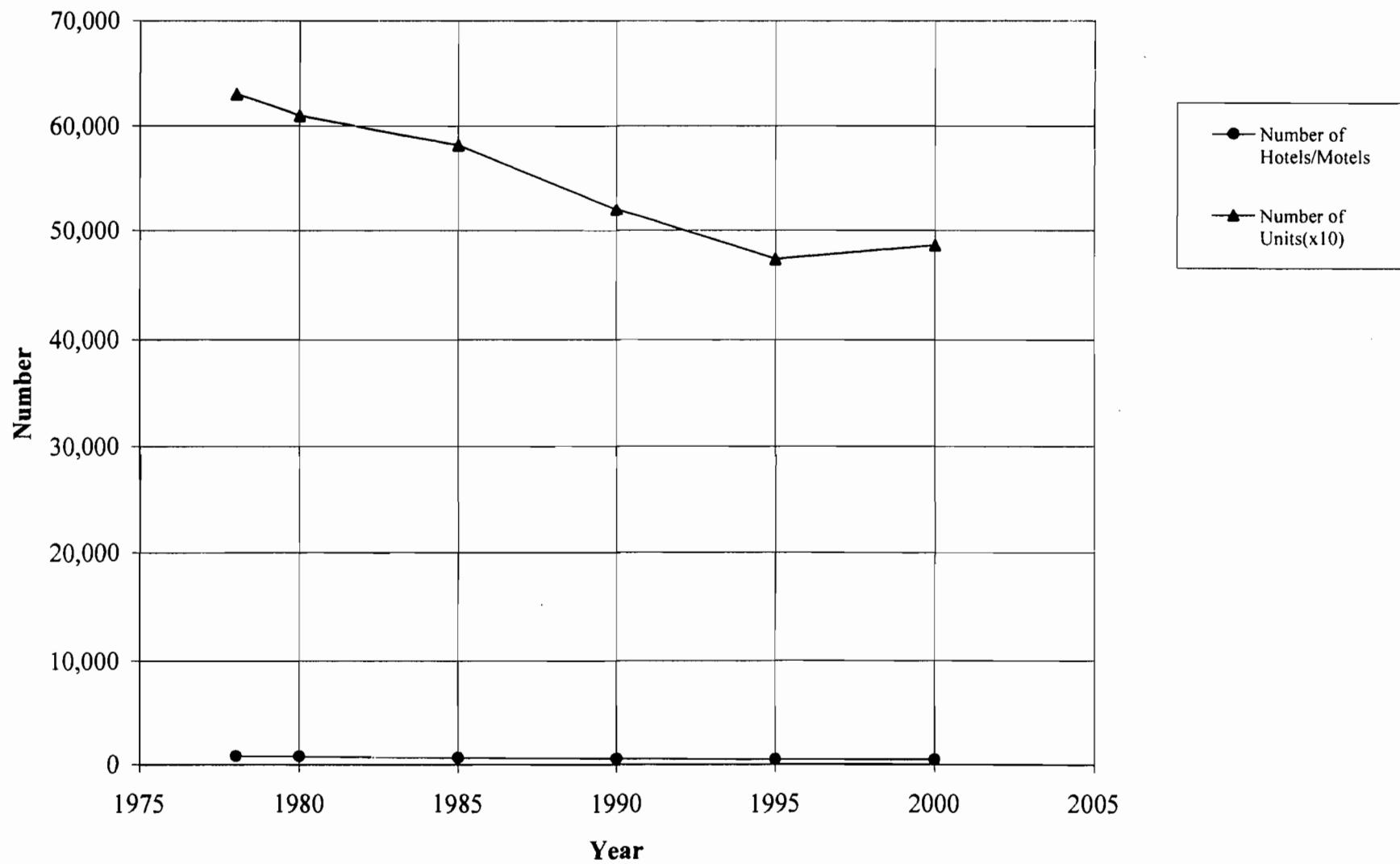


Figure 7-5. Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles for Miami-Dade County

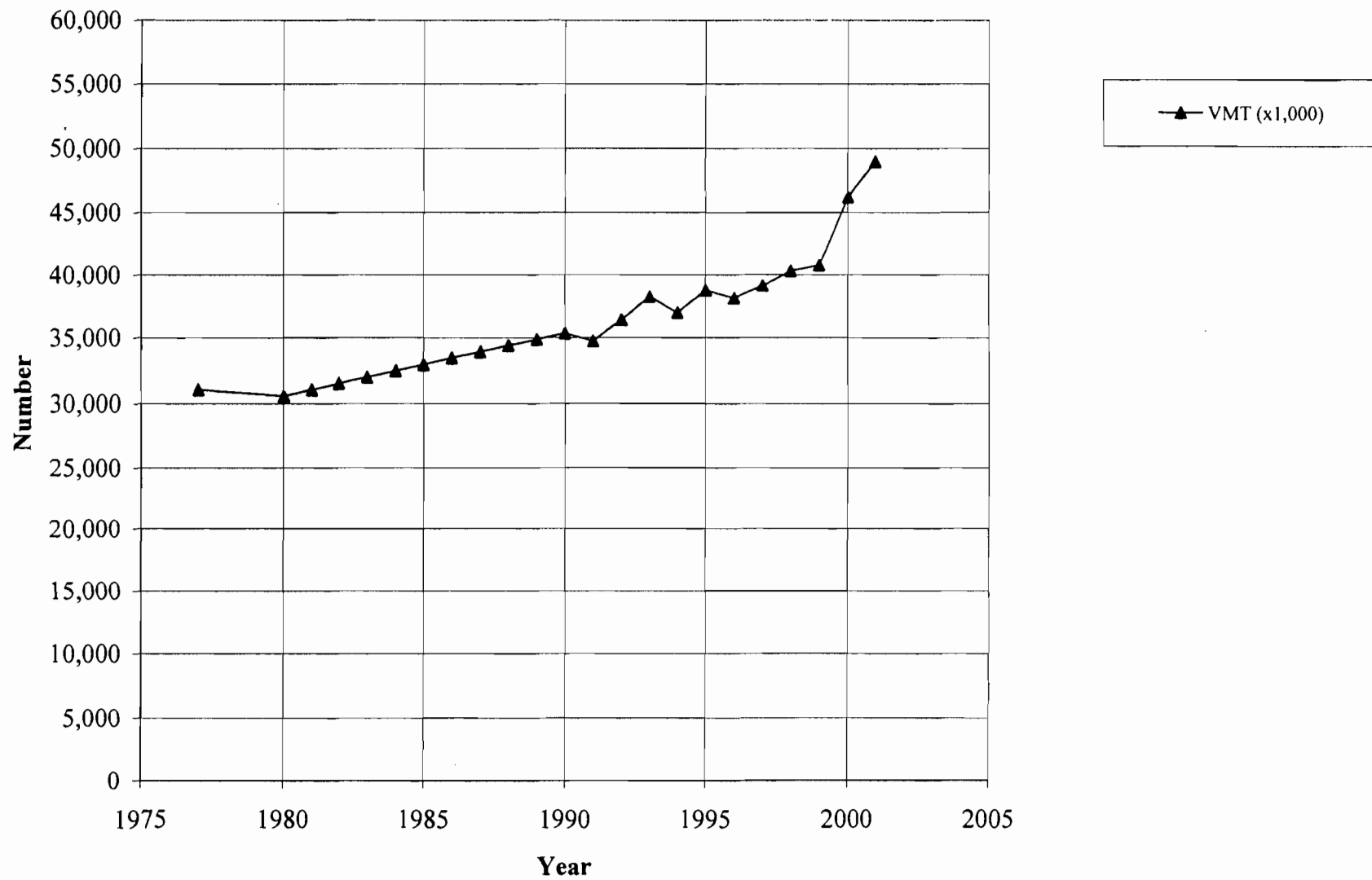


Figure 7-6. Manufacturing and Agriculture Trends in Miami-Dade County

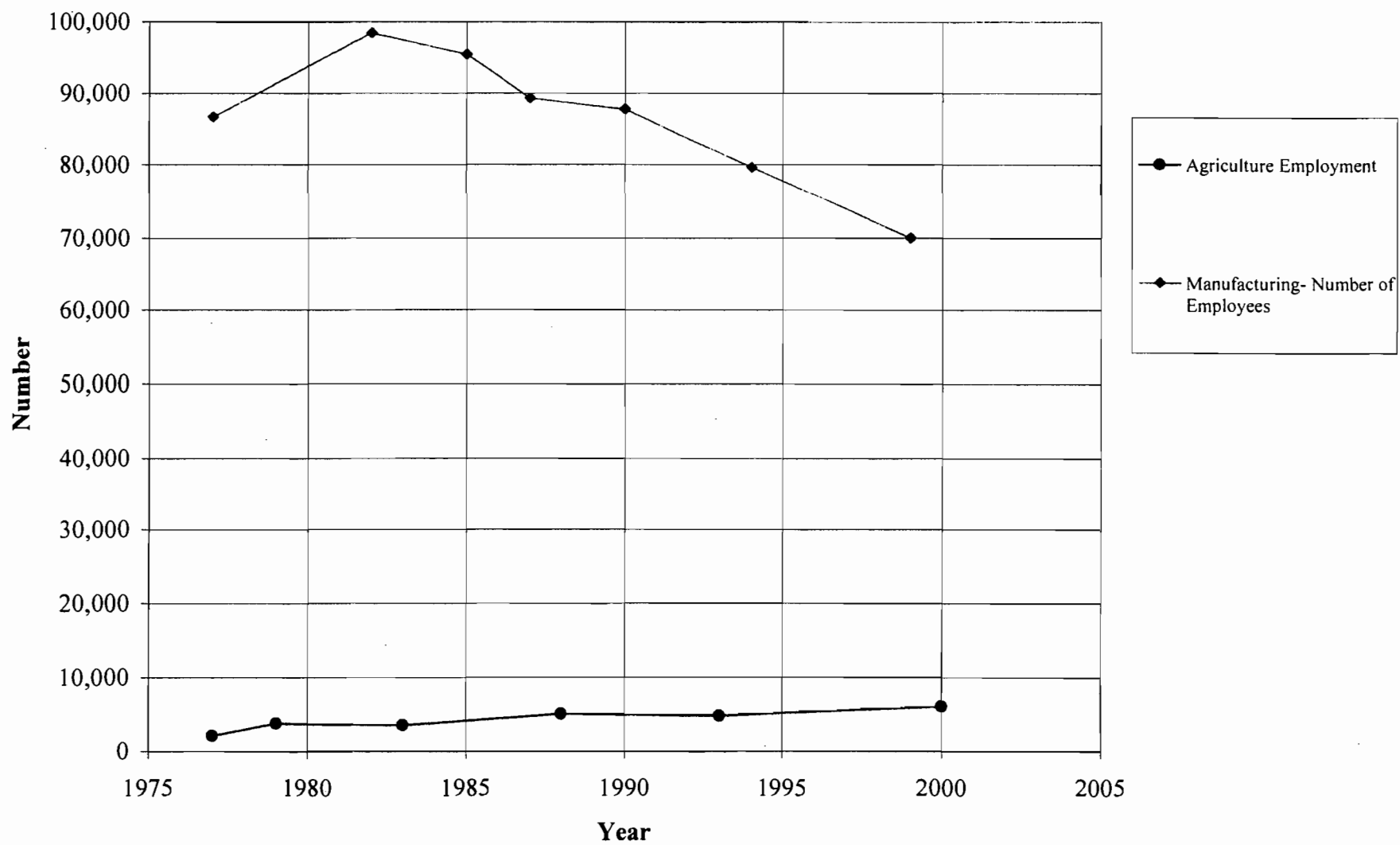


**Figure 7-7. Electrical Power Generation Capacity in
Miami-Dade County**

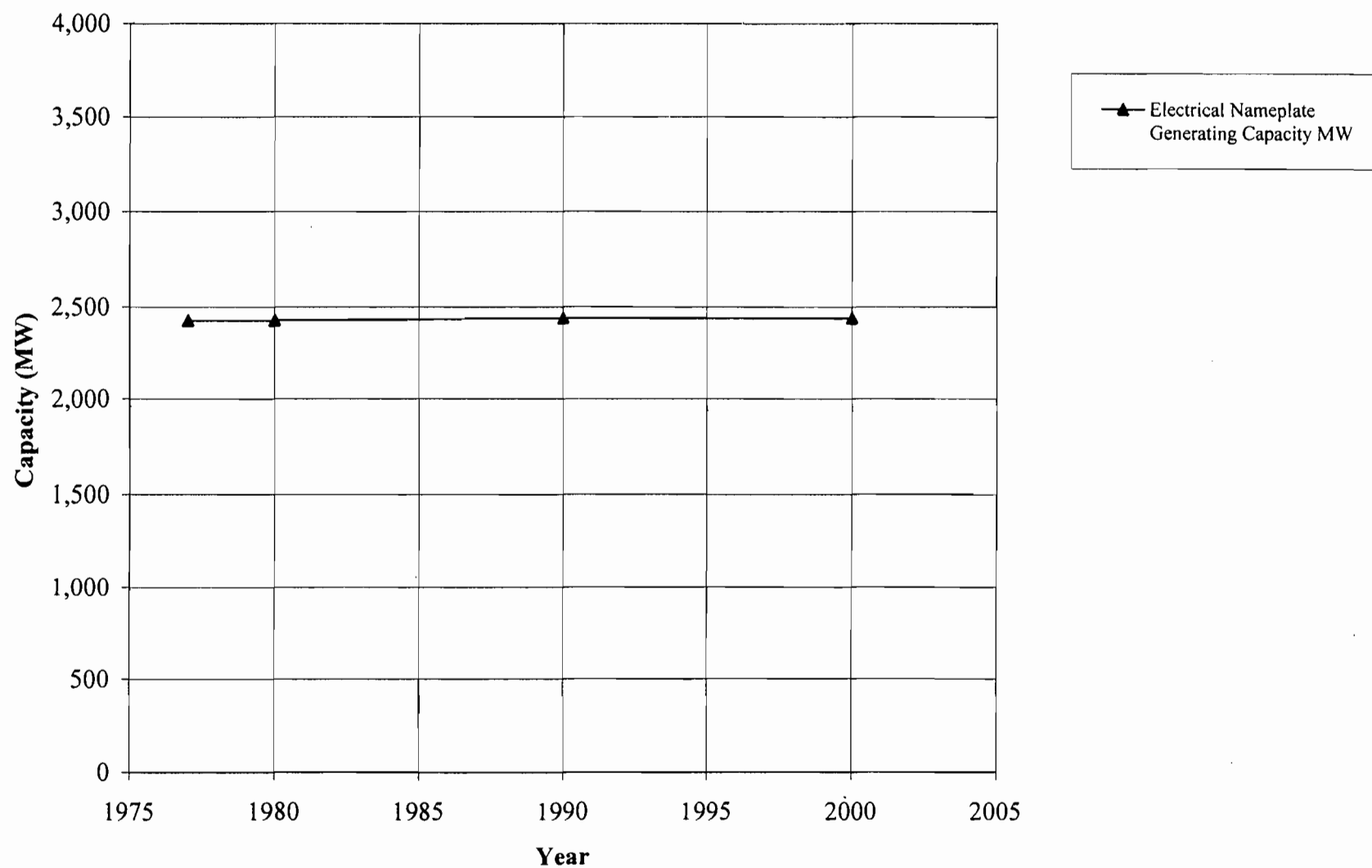


Figure 7-8. Mobile Source Emissions (Tons per Day) of CO, VOC, and NO_x in Miami-Dade County

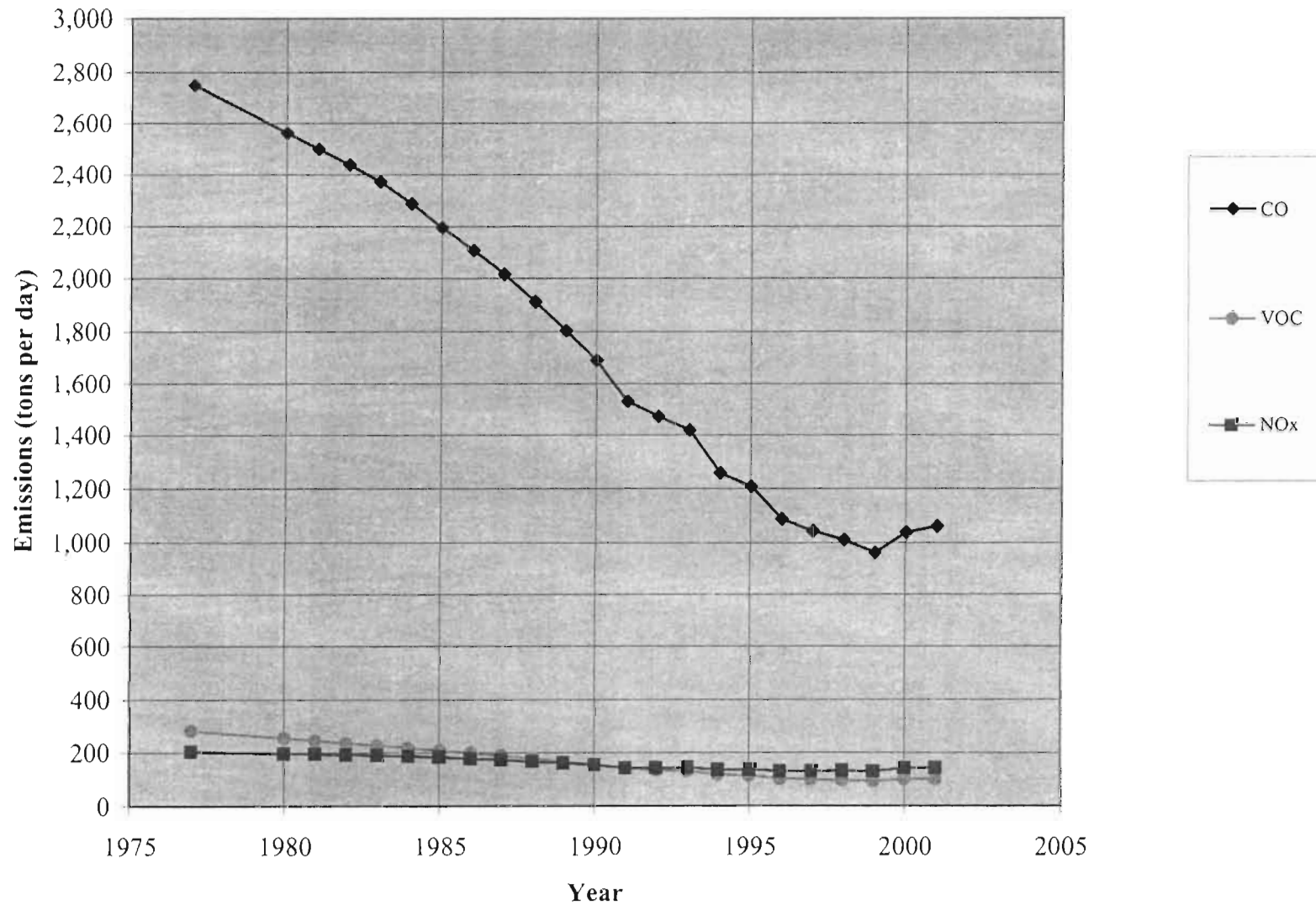


**Figure 7-9. Measured 3-Hour Average Sulfur Dioxide Concentrations
(2nd Highest Values) from 1981 to 2002- Miami-Dade County**

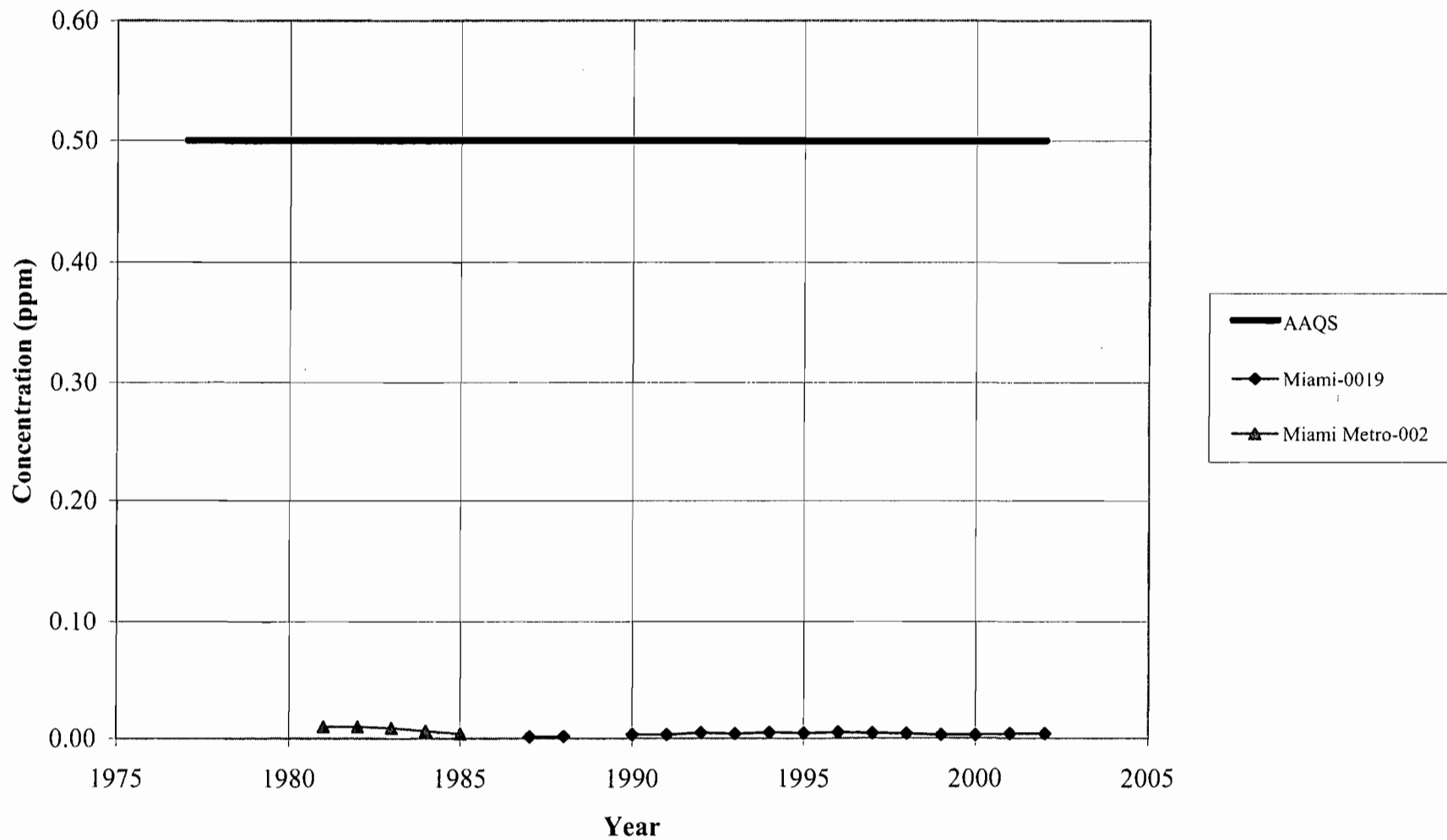


**Figure 7-10. Measured 24-Hour Average Sulfur Dioxide Concentrations
(2nd Highest Values) from 1981 to 2002- Miami-Dade County**

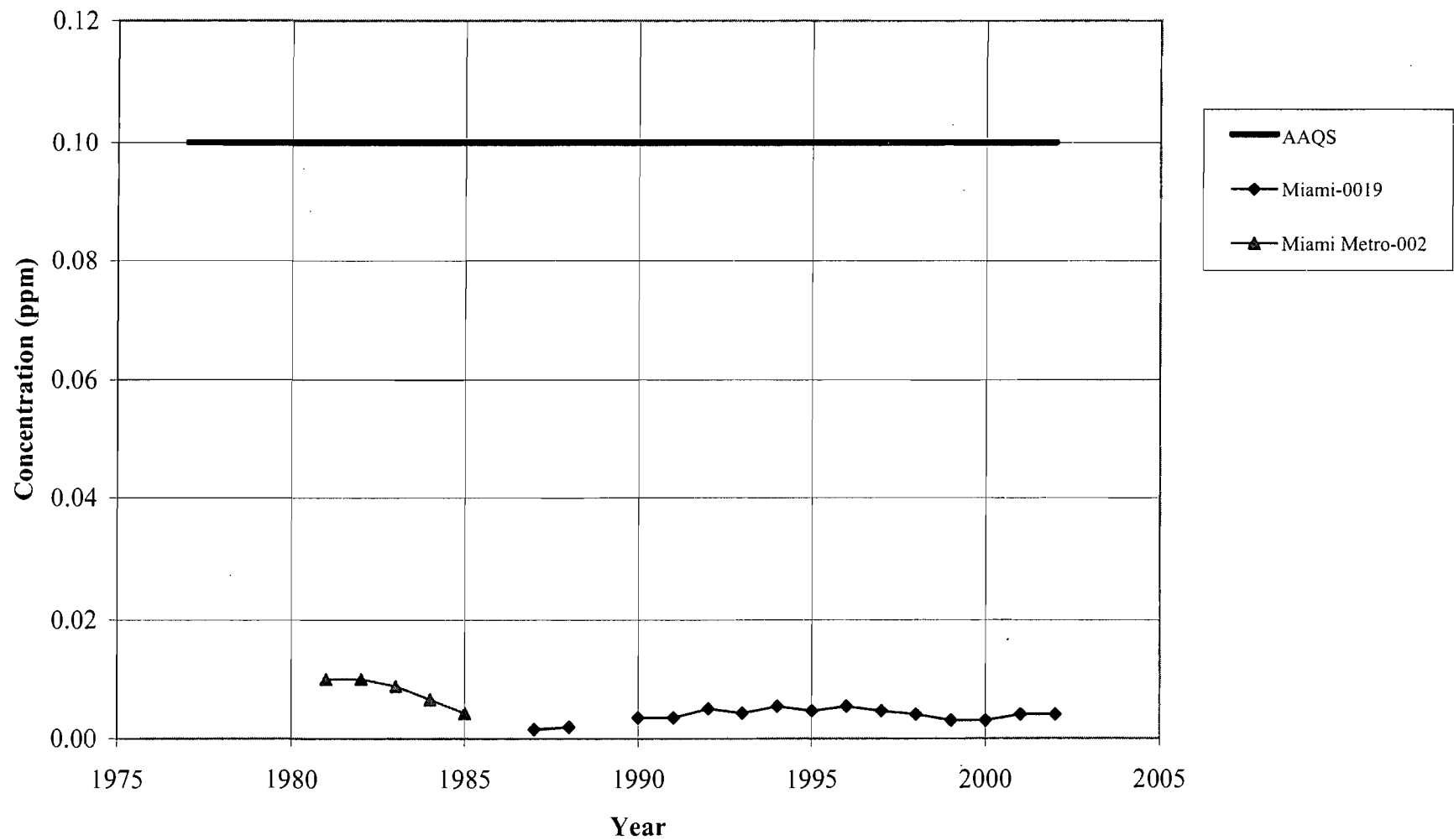


**Figure 7-11. Measured Annual Average Sulfur Dioxide Concentrations
from 1981 to 2002- Miami-Dade County**

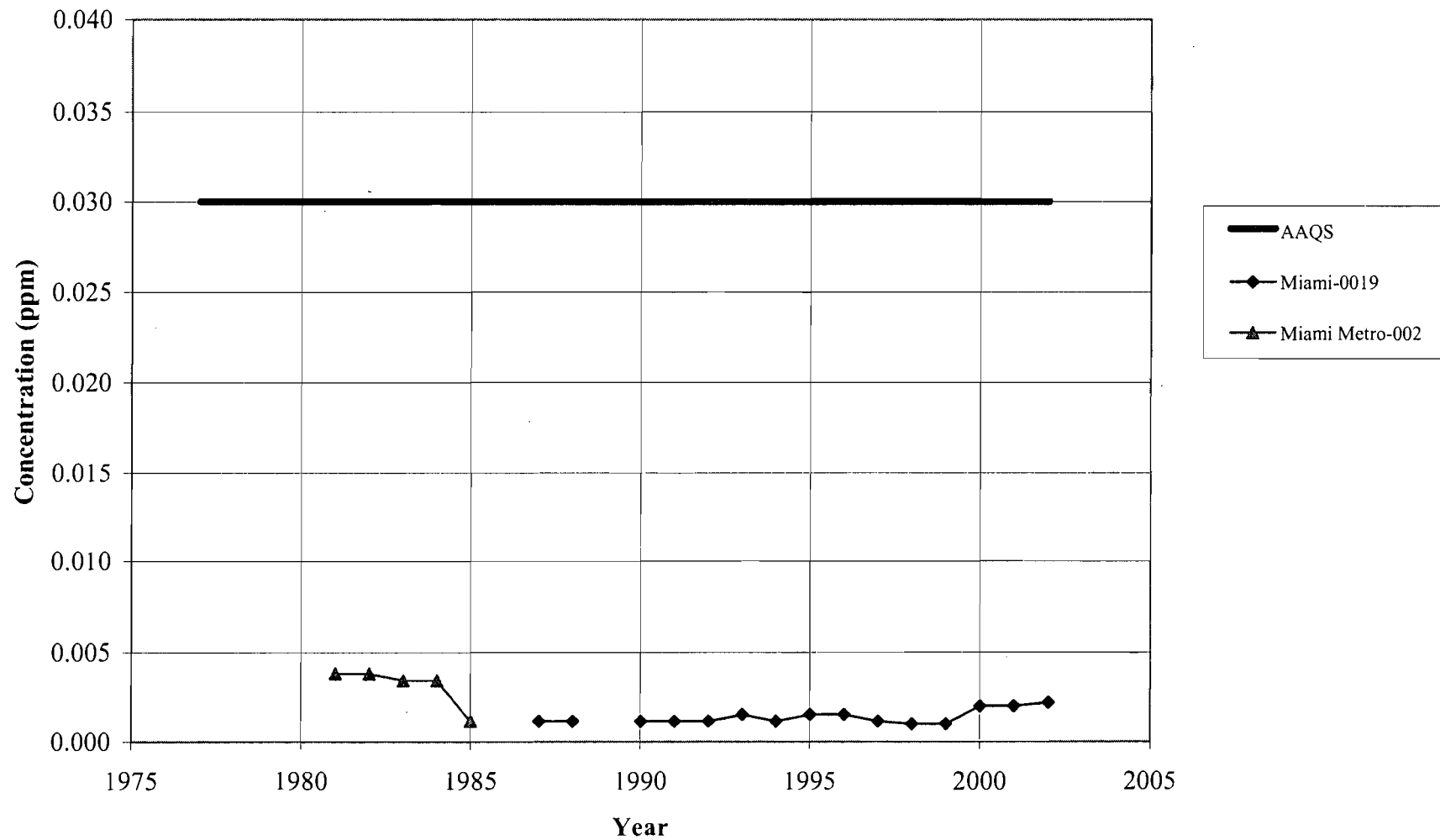


**Figure 7-12. Measured 24-Hour Average PM₁₀ Concentrations (1988 to 2002)
and Total Suspended Particulate Concentrations (1981 to 1987)
(2nd Highest Values) - Miami-Dade County**

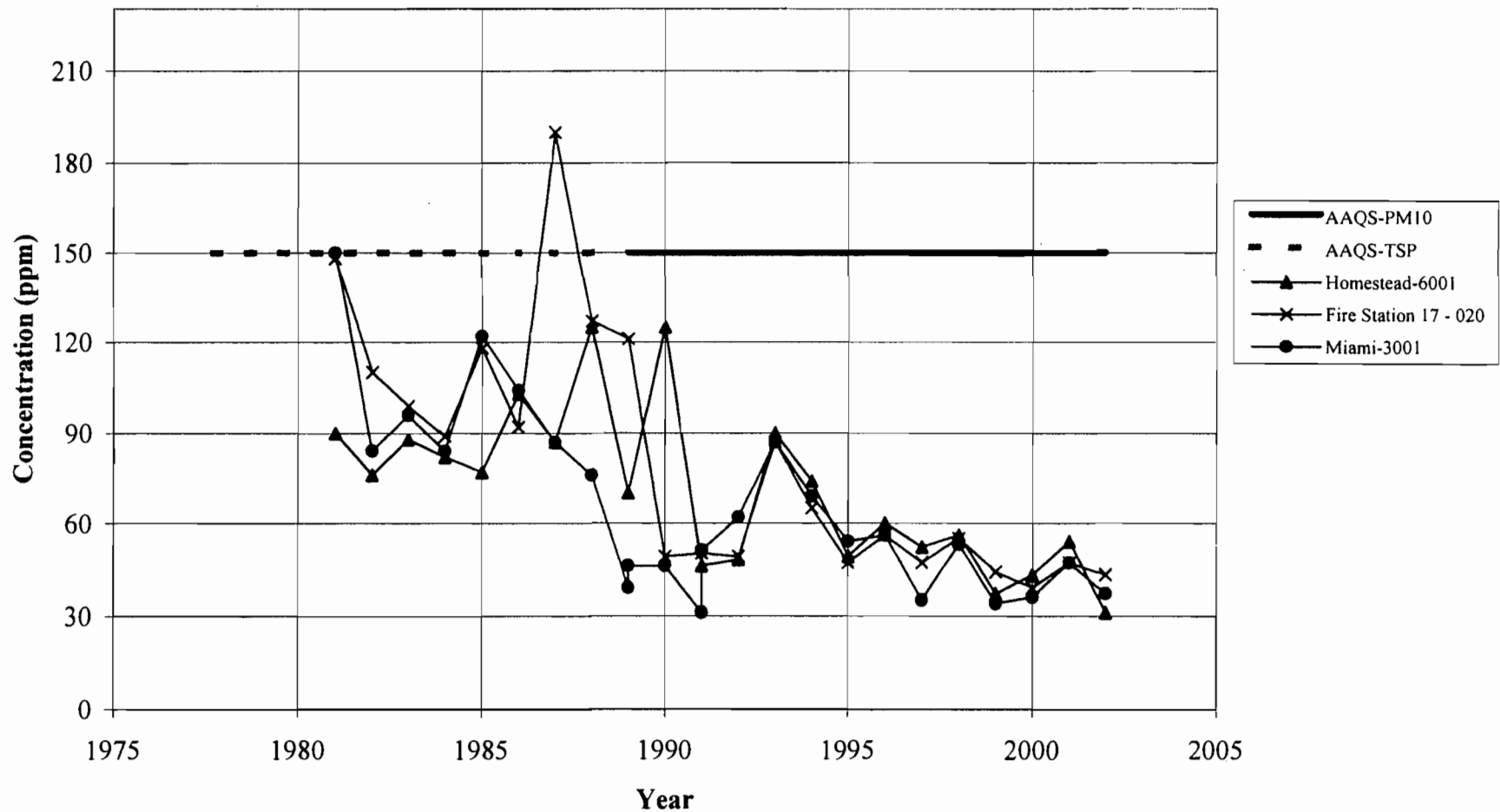


**Figure 7-13. Measured Annual Average PM₁₀ Concentrations (1988 to 2002)
and Total Suspended Particulate Concentrations (1981 to 1987) -
Miami-Dade County**

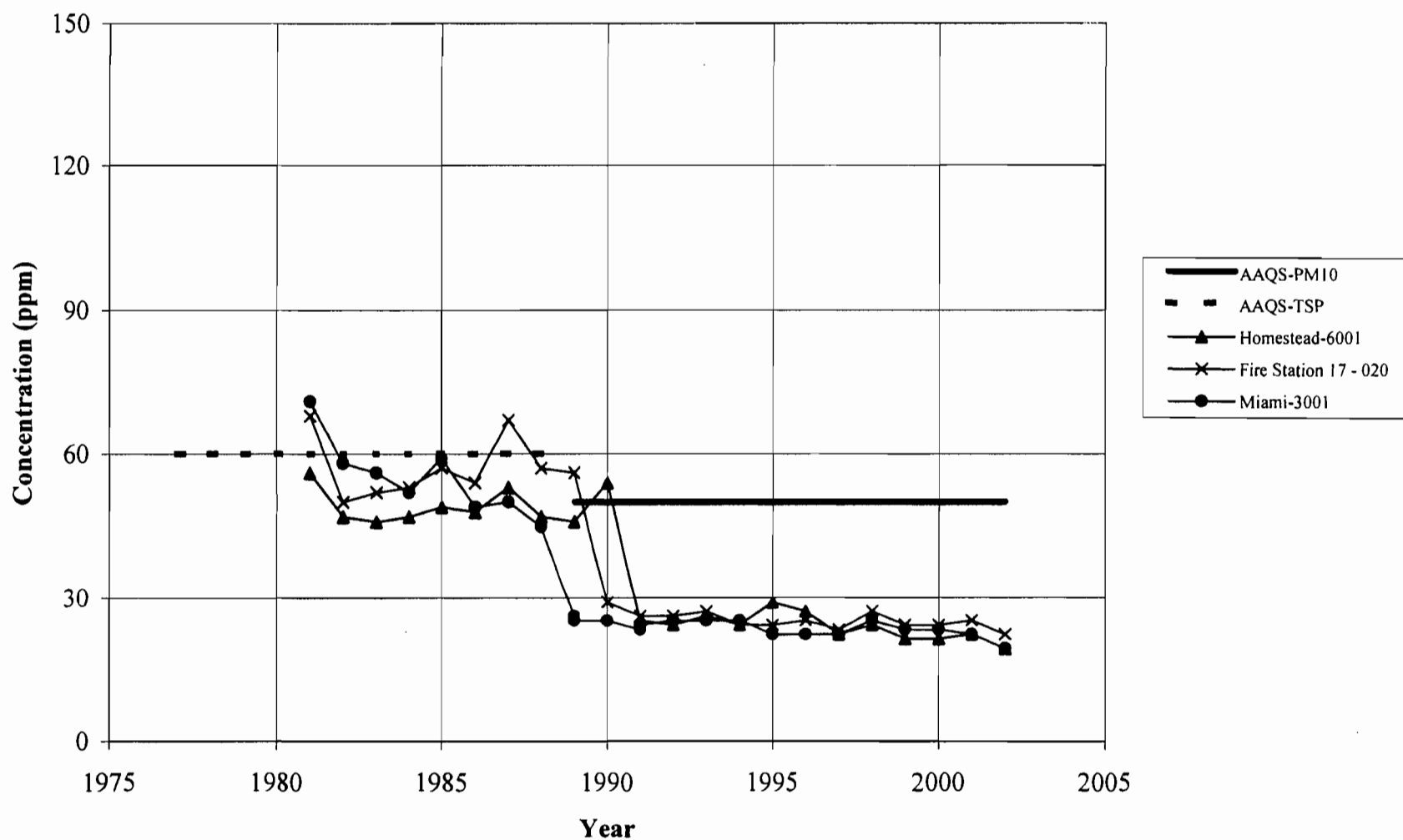


Figure 7-14. Measured Annual Average Nitrogen Dioxide Concentrations from 1981 to 2002 - Miami-Dade County

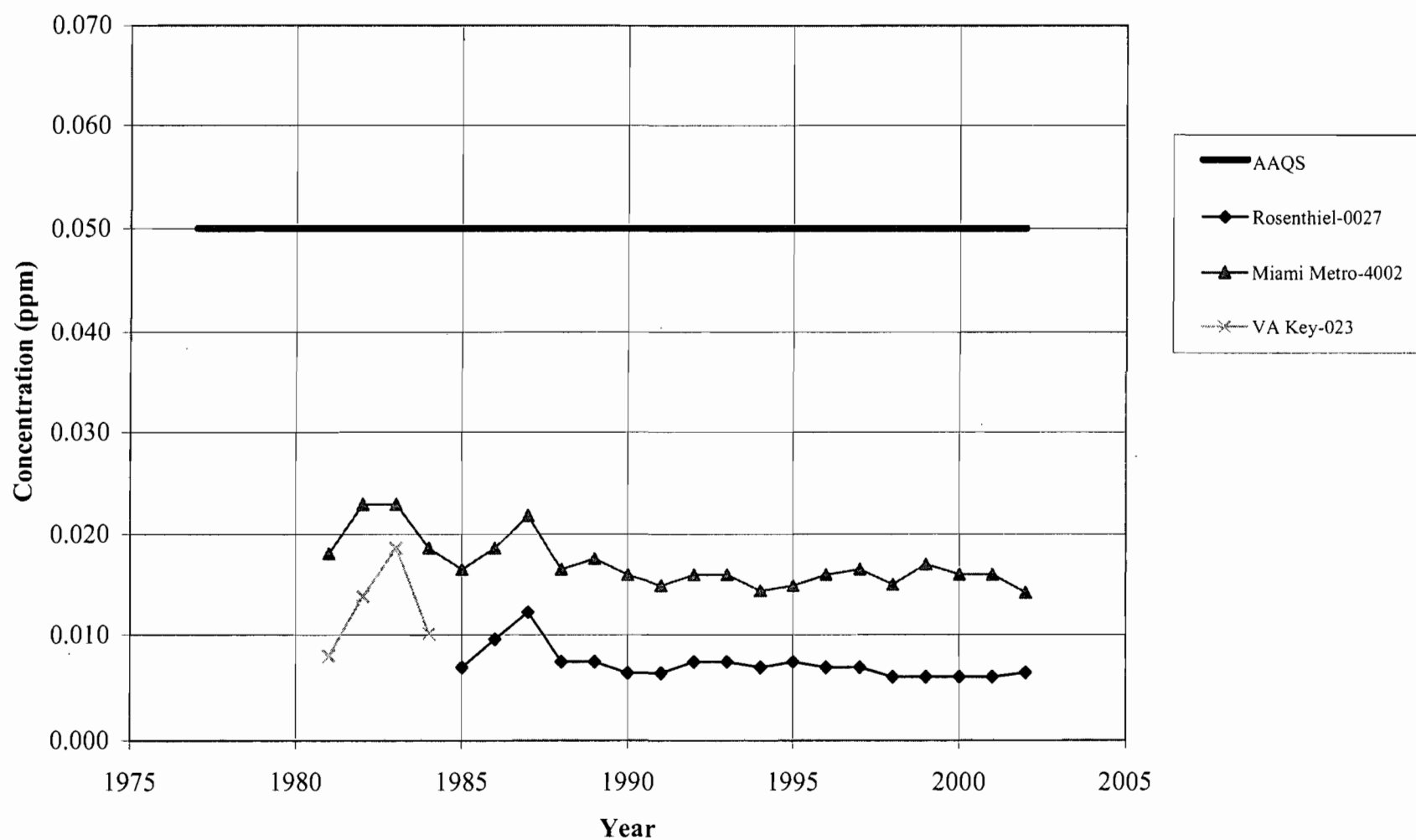


**Figure 7-15. Measured 1-Hour Average Carbon Monoxide Concentrations
(2nd Highest Values) from 1981 to 2002 - Miami-Dade County**

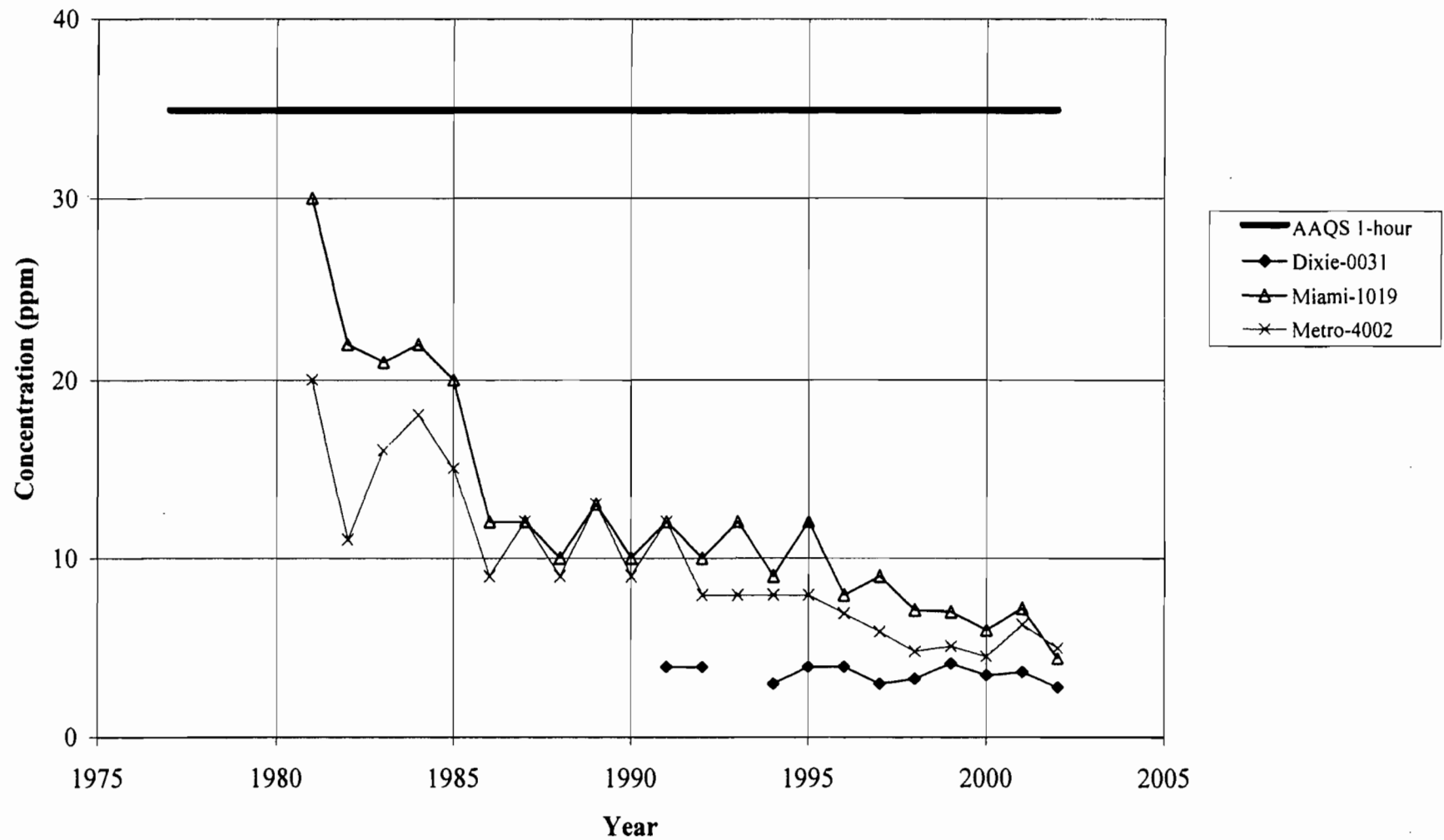


**Figure 7-16. Measured 8-Hour Average Carbon Monoxide Concentrations
(2nd Highest Values) from 1981 to 2002 - Miami-Dade County**

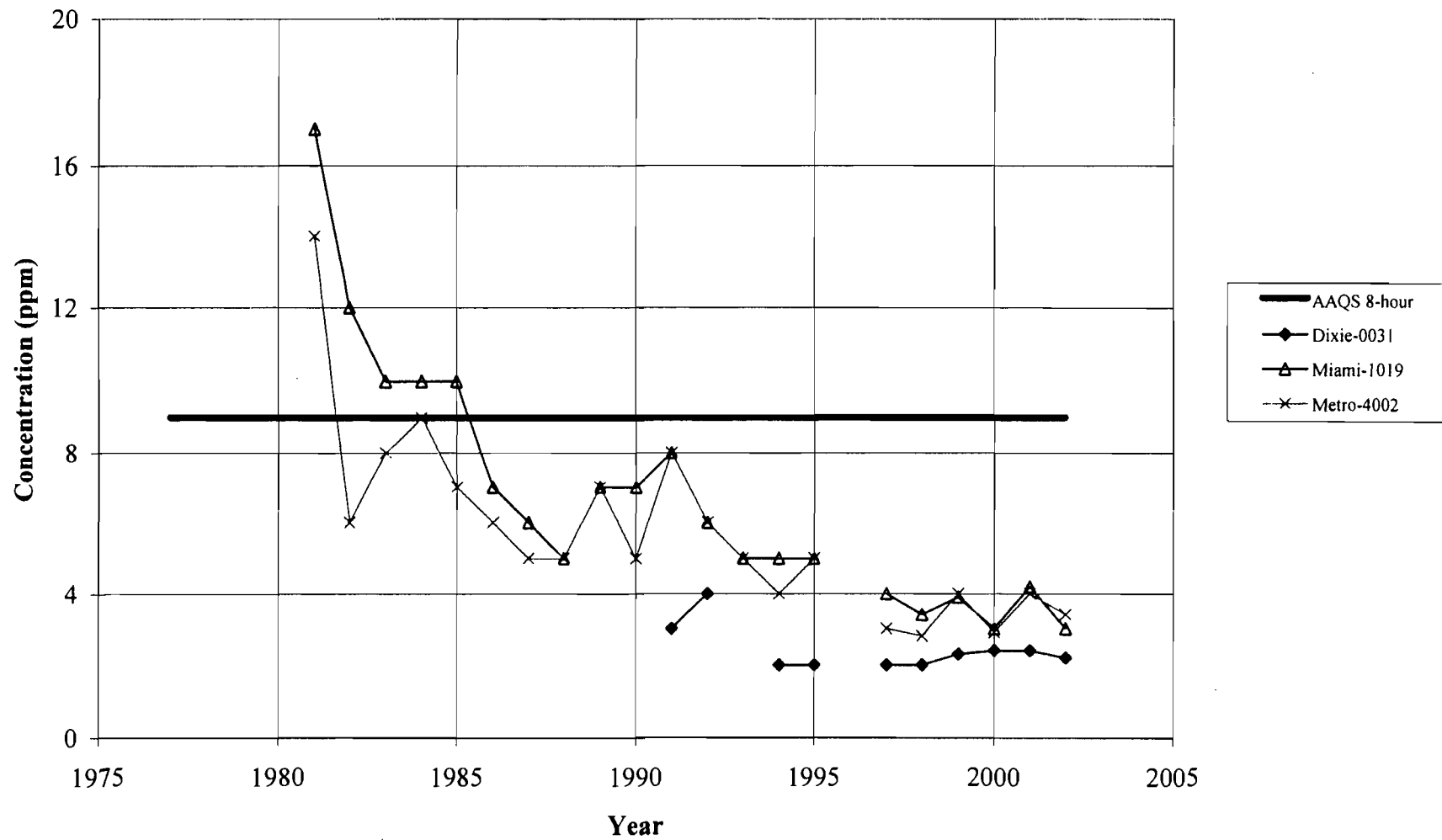
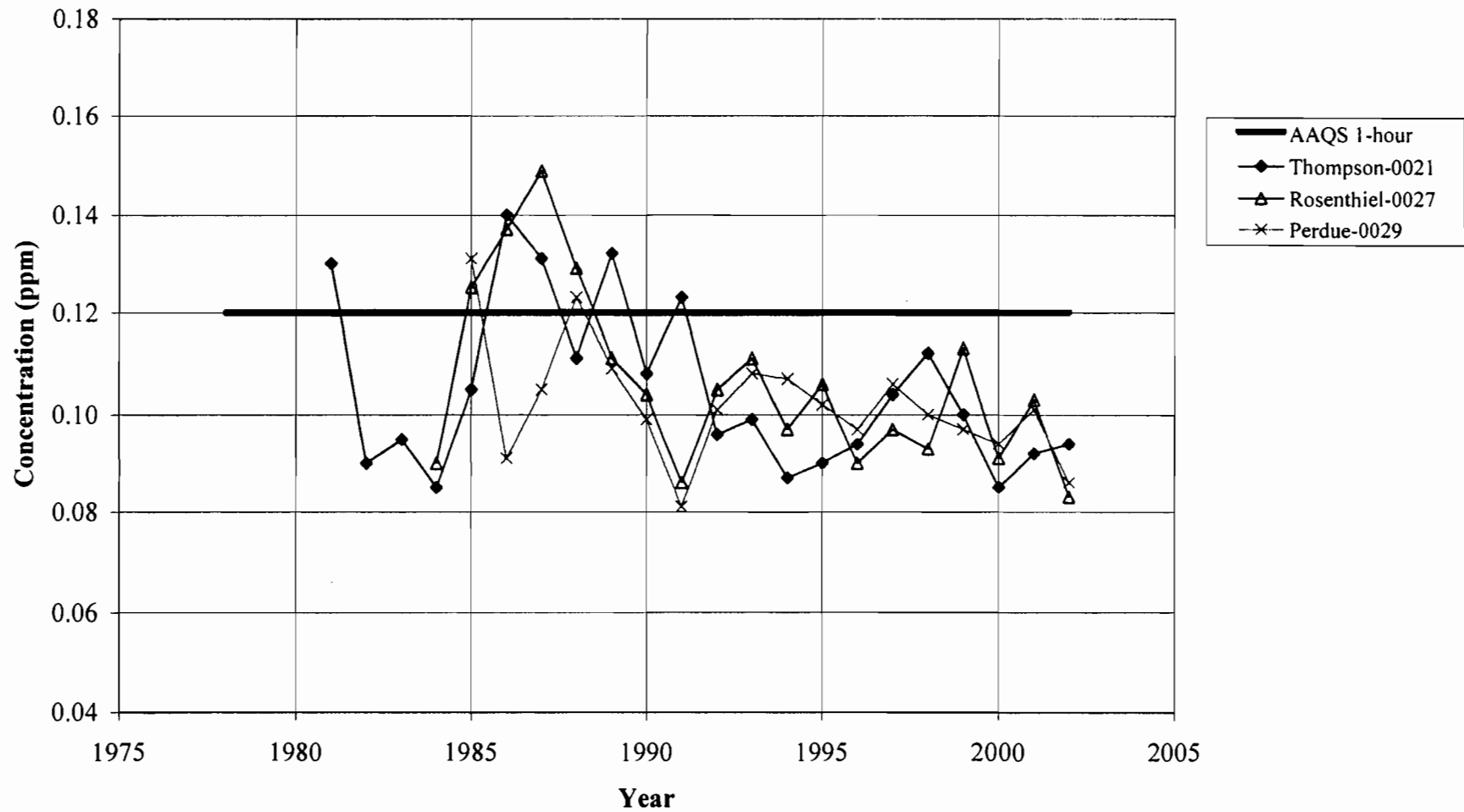


**Figure 7-17. Measured 1-Hour Average Ozone Concentrations
(2nd Highest Values) from 1981 to 2002 - Miami-Dade County**



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APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION ON "F" CLASS COMBUSTION TURBINE

(Note: SO₂ based on 0.2 gr/100 cf of H₂S. Actual total sulfur based on 1 gr/100 cf to account for odorant (mercaptans) in pipeline gas.)

APPENDIX A TO AIR CONSTRUCTION/PSD APPLICATION
DESCRIPTION OF EMISSIONS TABLES FOR TURKEY POINT EXPANSION PROJECT

Emission Tables – The following tables present the estimated emissions for the Turkey Point Expansion Project. Tables A-1 through A-8 present individual CT/HRSG performance and emissions when firing natural gas. Tables A-9 through A-14 present individual CT/HRSG performance and emissions when firing light oil. Tables A-15 and A-16 present emissions of hazardous air pollutants for natural gas and light oil firing, respectively. Tables A-15a and A-16a present emissions of formaldehyde for natural gas and light oil firing, respectively.

Table A-1 and A-2 includes performance and emissions for maximum duct firing at 550 MMBtu/hr (HHV). While this is the maximum design rate, the maximum duct firing is only used when one of the four CT/HRSG trains is not operating. This allows the maximum steam production from the CT/HRSG and provides the increased steam to the steam turbine/electric generator when only three CT/HRSG trains are operating. During normal operation the maximum heat input for the duct burners is 210 MMBtu/hr (HHV). This heat input combined with the heat recovered from the CT exhaust provides the maximum steam for the steam turbine/electric generator associated with Unit 5. Tables A-1 and A-2 also includes operation using power augmentation in the CT. During this mode of operation the duct burners would have a heat input of 360 MMBtu/hr with the additional steam injected into the CT to increase power production additional mass flow in the CT.

Tables A-17 and A-18 present the emissions and performance for natural gas firing that produce the maximum emissions with four CT/HRSG trains operating. These conditions are: 1) baseload operation with duct firing at 210 MMBtu/hr and a turbine inlet of 35°F, and 2) power augmentation with duct firing at 360 MMBtu/hr and a turbine inlet of 80°F. Power augmentation would occur during higher inlet temperatures that allows greater production of electric power.

Regional Haze Modeling – The air modeling evaluation to determine Regional Haze Impacts for the Project in the Everglades National Park Class I Area was based on the following conditions:

- Natural Gas – power augmentation with duct firing at 360 MMBtu/hr and a turbine inlet of 80°F. This operation, although limited to 400 hours per year, produces the highest combination of particulate matter, sulfur dioxide and nitrogen oxide emissions.

- Light Oil – baseload operation and a turbine inlet of 35°F. While this condition is extremely rare in south Florida, it produces the highest combination of particulate matter, sulfur dioxide and nitrogen oxide emissions.

The speciation of particulate matter used in the Regional Haze modeling is shown in Tables A-19 and A-20 for natural gas and light oil firing. For natural gas firing, the filterable particulate from the CT was based on “soil”. This is supported by information from the CT manufacturer, General Electric (GE) which stated that PM emissions are essentially zero from the combustion process and that any PM is a result of other factors. GE’s letter is included in this appendix. From a combustion standpoint the DLN combustion process pre-mixes the natural gas and air. The pre-mixing of the fuel and air, along with combustion temperatures of 2,600°F, suggests that combustion components such as “elemental carbon” would not occur. Indeed, the combustion temperature of carbon is about 1,200°F. For emissions from the duct burner, it was assumed that all filterable particulate was elemental carbon. Filterable particulate was also added from the SCR system. This filterable particulate was assumed to be soil. The condensable emissions from the CT and duct burners are based on manufacturer guarantees. The sulfuric acid mist was based on the maximum amount of sulfur in the natural gas. It should be noted that emissions of sulfur dioxide, SCR filterable particulate and sulfuric acid mist were determined independently and not adjusted for the total amount of sulfur in the fuel. Therefore, these emissions are overstated and conservative for the analysis.

For light oil firing, the filterable particulate from the CT was based on the manufacturer guarantee with the “elemental carbon” component being the average emission rates from tests and the “soil” component the remainder. This is supported by information from the CT manufacturer, GE which stated that PM emissions are essentially zero from the combustion process and that any PM is a result of other factors. GE’s letter is included in this appendix. This is also supported from a combustion standpoint since combustion temperatures are 2,600°F and the combustion temperature of carbon is about 1,200°F. Filterable particulate was also added from the SCR system. This filterable particulate was assumed to be soil. The condensable emissions from the CT and duct burners are based on the average emission tests from GE and subtracting out components associated with fuel sulfur. In the GE letter the average condensable emissions are 14 lb/hr with a contribution of 10 lb/hr from fuel sulfur content (0.05 percent). Unit 5 will use ultra low sulfur content light oil (i.e., 0.0015 percent) that will contribute virtually no sulfur components to condensable particulate. The sulfuric acid mist was based on the maximum amount of sulfur in the light oil. It should be noted that emissions of

sulfur dioxide, SCR filterable particulate and sulfuric acid mist were determined independently and not adjusted for the total amount of sulfur in the fuel. Therefore, these emissions are overstated and conservative for the analysis. In addition, the ultra low sulfur content light oil will be comparable in quality to natural gas. For example, the maximum SO₂ emissions from burning natural gas at 2 grains/100 scf is about 9 lb/hr per CT, while the SO₂ emissions firing light oil with a sulfur content of 0.0015 percent is about 3 lb/hr. It is likely that the assumed amount of filterable particulate is high since this guarantee is based on 0.05-percent sulfur fuel currently available. This is also supported by tests conducted on four GE Frame 7FA turbines at FPL facilities using 0.05 percent sulfur distillate oil. The median value for 11 test runs was 3.6 lb filterable particulate. The 4.8 lb/hr assumed as elemental carbon is conservative for ultra low sulfur content light oil.

Table A-1. Design Information and Stack Parameters for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only					CT with Duct Burner				
	Turbine Inlet Temperature					Turbine Inlet Temperature				
	35 °F Case 8	59 °F Case 6	75 °F Case 4	80 °F PAug	95 °F Case 2	35 °F w/DB Case 7	59 °F w/DB Case 5	75 °F w/DB Case 3	80 °F w/DB PAug	95 °F w/DB Case 1
Combustion Turbine Performance										
Net power output (MW)	181.64	172.44	163.14	164.44	149.74	181.64	172.44	163.14	164.44	149.74
Net heat rate (Btu/kWh, LHV)	9,213	9,280	9,412	9,440	9,666	9,213	9,280	9,412	9,440	9,666
(Btu/kWh, HHV)	10,227	10,301	10,447	10,481	10,729	10,227	10,301	10,447	10,481	10,729
Heat input (MMBtu/hr, LHV)	1,674	1,600	1,536	1,552.7	1,447	1,674	1,600	1,536	1,552.7	1,447
(MMBtu/hr, HHV)	1,858	1,776	1,704	1,723	1,607	1,858	1,776	1,704	1,723	1,607
Inlet Fogger	Off	Off	Off	On	Off	Off	Off	Off	On	Off
Relative Humidity (%)	20	60	60	60	50	20	60	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110
Duct Burner (DB)										
Heat input (MMBtu/hr, HHV)	0	0	0	0	0	550	550	550	550	550
(MMBtu/hr, LHV)	0	0	0	0	0	495.5	495.5	495.5	495.5	495.5
CT/DB Exhaust Flow										
Mass flow (lb/hr)- with no margin	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	3,728,099.6	3,561,100	3,440,100	3,466,100	3,279,100
- provided	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000					
Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
Moisture (% Vol.)	7.56	8.39	9.04	9.7	9.92	9.59	10.50	11.21	12.49	12.17
Oxygen (% Vol.)	12.60	12.44	12.36	12.19	12.27	10.35	10.10	9.94	10.34	9.75
Molecular Weight	28.49	28.39	28.33	28.25	28.22	28.36	28.26	28.18	29.68	28.08
Fuel Usage										
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))										
Heat input (MMBtu/hr, LHV)	1,674	1,600	1,536	1,553	1,447	1,674	1,600	1,536	1,553	1,447
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	80,322	76,808	73,698	74,524	69,470	80,322	76,808	73,698	74,524	69,470
Heat content (Btu/cf, LHV)- assumed	933	933	933	933	933	933	933	933	933	933
Fuel density (lb/ft)	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662
Fuel Usage - Duct Burner Only										
Fuel usage (lb/hr)- calculated	0	0	0	0	0	23,782	23,782	23,782	23,782	23,782
Fuel usage (cf/hr)- calculated	0	0	0	0	0	530,846	530,846	530,846	530,846	530,846
HRSG Stack										
HRSG - Stack Height (ft)	131	131	131	131	131	131	131	131	131	131
Diameter (ft)	19	19	19	19	19	19	19	19	19	19
CT Flow Conditions										
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr										
Mass flow (lb/hr)	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	NA	NA	NA	NA	NA
Temperature (°F)	1,095	1,116	1,128	1,125	1,143	NA	NA	NA	NA	NA
Molecular weight	28.49	28.39	28.33	28.25	28.22	NA	NA	NA	NA	NA
Volume flow (acfm)- calculated	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	NA	NA	NA	NA	NA
(ft/s)- calculated	41,009	39,824	38,850	39,169	37,505	NA	NA	NA	NA	NA
Diameter (ft)	22	22	22	22	22	NA	NA	NA	NA	NA
Velocity (ft/sec)- calculated	107.9	104.8	102.2	103.0	98.7	NA	NA	NA	NA	NA
HRSG Stack Flow Conditions										
Velocity (ft/sec) = Volume flow (acfm) / [(diameter) ² / 4] x 3.14159 / 60 sec/min										
Mass flow (lb/hr)	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	3,728,100	3,561,100	3,440,100	3,466,100	3,279,100
HRSG Stack Temperature (°F)	203	202	204	204	201	189	188	189	188	190
Molecular weight	28.49	28.39	28.33	28.25	28.22	28.36	28.26	28.18	29.68	28.08
Volume flow (acfm)	1,048,619	1,004,150	974,675	984,548	927,921	1,037,294	993,802	964,236	920,636	923,335
Diameter (ft)	19	19	19	19	19	19	19	19	19	19
Velocity (ft/sec)- calculated	61.6	59.0	57.3	57.9	54.5	61.0	58.4	56.7	54.1	54.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft²

Source: GE, 2000 - CT Performance Data; Golder Associates, 2003 - DB Calculations

Table A-2. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only					CT with Duct Burner				
	Turbine Inlet Temperature					Turbine Inlet Temperature				
	35 °F	59 °F	75 °F	80 °F	95 °F	35 °F w/DB	59 °F w/DB	75 °F w/DB	80 °F w/DB	95 °F w/DB
	Case 8	Case 6	Case 4	PAug	Case 2	Case 7	Case 5	Case 3	PAug	Case 1
HRSG Stack Emission rate (lb/hr)	1.02	0.98	0.94	0.95	0.89	1.33	1.28	1.24	1.25	1.19
<u>Lead</u>										
Lead (lb/hr) = NA										
Emission Rate Basis	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O₂ oxygen.

Source: GE, 2000 - CT Performance Data; Golder Associates, 2003 - DB Calculations

Table A-3. Design Information and Stack Parameters for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 12	59 °F Case 11	75 °F Case 10	95 °F Case 9
Combustion Turbine Performance				
Net power output (MW)	136.7	129.24	122.24	112.24
Net heat rate (Btu/kWh, LHV)	9,855	10,043	10,236	10,602
(Btu/kWh, HHV)	10,939	11,148	11,362	11,769
Heat Input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
(MMBtu/hr, HHV)	1,495	1,441	1,389	1,321
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,979,000	2,888,000	2,803,000	2,694,000
- provided	2,979,000	2,888,000	2,803,000	2,694,000
Temperature (°F)	1,122	1,139	1,153	1,170
Moisture (% Vol.)	7.49	8.27	8.92	9.8
Oxygen (% Vol.)	12.67	12.57	12.49	12.41
Molecular Weight	28.50	28.41	28.33	28.23
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	64,660	62,299	60,058	57,115
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft³)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,443,832	1,391,103	1,341,054	1,275,357
HRSG Stack				
HRSG - Stack Height (ft)	131	131	131	131
Diameter (ft)	19	19	19	19
CT Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F) + 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,979,000	2,888,000	2,803,000	2,694,000
Temperature (°F)	1,122	1,139	1,153	1,170
Molecular weight	28.50	28.41	28.33	28.23
Volume flow (acfm)- calculated	2,011,853	1,977,488	1,941,432	1,892,412
(ft³/s)- calculated	33,531	32,958	32,357	31,540
Diameter (ft)	22.0	22.0	22.0	22.0
Velocity (ft/sec)- calculated	88.2	86.7	85.1	83.0
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [(diameter)² / 4] x 3.14159 / 60 sec/min				
Mass flow (lb/hr)	2,979,000	2,888,000	2,803,000	2,694,000
HRSG Stack Temperature (°F)	187	188	189	190
Molecular weight	28.50	28.41	28.33	28.23
CT volume flow (acfm)	822,545	801,136	781,026	754,411
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	48.4	47.1	45.9	44.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft²

Source: GE, 2000 - CT Performance Data.

Table A-4. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 12	59 °F Case 11	75 °F Case 10	95 °F Case 9
<u>Particulate from CTand SCR</u>				
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only				
a. PM ₁₀ (front half) (lb/hr)				
CT- provided	9.0	9.0	9.0	9.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)				
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) x conversion of SO ₂ to SO ₃ x lb SO ₃ /lb SO ₂ x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x lb (NH ₄) ₂ SO ₄ / lb SO ₃				
SO ₂ emission rate (lb/hr)- calculated	8.3	7.9	7.7	7.3
Conversion (%) from SO ₂ to SO ₃	9.8	9.8	9.8	9.8
MW SO ₃ / SO ₂ (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100	100
MW (NH ₄) ₂ SO ₄ / SO ₃ (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.67	1.61	1.55	1.47
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0
Total HRSG stack emission rate (lb/hr) [a + b]	10.7	10.6	10.5	10.5
(lb/mmBtu, HHV)	0.0068	0.0070	0.0072	0.0075
<u>Sulfur Dioxide</u>				
SO ₂ (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO ₂ /lb S) /100				
Fuel use (cf/hr)	1,443,832	1,391,103	1,341,054	1,275,357
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO ₂ /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	8.3	7.9	7.7	7.3
<u>Nitrogen Oxides</u>				
NOx (lb/hr) = NOx (ppmvd @ 15% O ₂) x {[20.9 x (1-Moisture (%)/100) - Oxygen, dry(%)] x 2116.8 lb/ft ² x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT / DB, ppmvd @15% O ₂	9	9	9	9
Moisture (%)	7.49	8.27	8.92	9.8
Oxygen (%)	12.67	12.57	12.49	12.41
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
CT/DB Emission rate (lb/hr)	48.9	47.1	45.4	43.1
HRSG Stack, ppmvd @ 15% O ₂	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	13.6	13.1	12.6	12.0
<u>Carbon Monoxide</u>				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft ² x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	9	9	9	9
Moisture (%)	7.49	8.27	8.92	9.8
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
HRSG Exhaust Temperature (°F)	187	188	189	190
Emission rate (lb/hr)- provided	24.4	23.5	22.7	21.7

Table A-4. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F	59 °F	75 °F	95 °F
	Case 12	Case 11	Case 10	Case 9
<u>Volatile Organic Compounds</u>				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%) / 100] x 2116.8 lb/ft ² x Volume flow (acfm) x				
16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	1.4	1.4	1.4	1.4
Moisture (%)	7.49	8.27	8.92	9.8
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
HRSG Exhaust Temperature (°F)	186.8	186.8	186.8	186.8
Emission rate (lb/hr)	2.17	2.09	2.02	1.93
<u>Sulfuric Acid Mist</u>				
Sulfuric Acid Mist (lb/hr) = SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight) / 100				
CT SO ₂ emission rate (lb/hr) - provided	8.3	7.9	7.7	7.3
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10	10
DB SO ₂ emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H ₂ SO ₄ (%) - provided	20	20	20	20
Emission rate (lb/hr)- calculated	0.83	0.79	0.77	0.73
<u>Lead</u>				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-5. Design Information and Stack Parameters for FPL Turkey Point Combined-Cycle Expansions Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Combustion Turbine Performance				
Net power output (MW)	91.1	86.5	81.34	74.64
Net heat rate (Btu/kWh, LHV)	11,820	12,050	12,415	12,866
(Btu/kWh, HHV)	13,120	13,375	13,780	14,281
Heat Input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
(MMBtu/hr, HHV)	1,195	1,157	1,121	1,066
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,456,000	2,396,000	2,336,000	2,267,000
- provided	2,456,000	2,396,000	2,336,000	2,267,000
Temperature (°F)	1,168	1,184	1,195	1,200
Moisture (% Vol.)	7.21	7.97	8.62	9.45
Oxygen (% Vol.)	12.99	12.90	12.83	12.80
Molecular Weight	28.51	28.43	28.35	28.25
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	51,682	50,026	48,467	46,091
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft ³)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,154,037	1,117,062	1,082,231	1,029,181
HRSG Stack				
HRSG - Stack Height (ft)	131	131	131	131
Diameter (ft)	19	19	19	19
CT Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,456,000	2,396,000	2,336,000	2,267,000
Temperature (°F)	1,168	1,184	1,195	1,200
Molecular weight	28.51	28.43	28.35	28.25
Volume flow (acfm)- calculated	1,705,874	1,685,637	1,658,984	1,620,525
(ft ³ /s)- calculated	28,431	28,094	27,650	27,009
Diameter (ft)	22.0	22.0	22.0	22.0
Velocity (ft/sec)- calculated	74.8	73.9	72.7	71.1
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	2,456,000	2,396,000	2,336,000	2,267,000
HRSG Stack Temperature (°F)	175	178	175	182
Molecular weight	28.51	28.43	28.35	28.25
CT volume flow (acfm)	665,689	653,646	636,829	626,928
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	39.1	38.4	37.4	36.9

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2000 - CT Performance Data.

Table A-6. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Particulate from CTand SCR				
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only				
a. PM ₁₀ (front half) (lb/hr)				
CT- provided	9.0	9.0	9.0	9.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)				
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) x conversion of SO ₂ to SO ₃ x lb SO ₃ /lb SO ₂ x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x lb (NH ₄) ₂ SO ₄ / lb SO ₃				
SO ₂ emission rate (lb/hr)- calculated	6.6	6.4	6.2	5.9
Conversion (%) from SO ₂ to SO ₃	9.8	9.8	9.8	9.8
MW SO ₃ / SO ₂ (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100	100
MW (NH ₄) ₂ SO ₄ / SO ₃ (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.33	1.29	1.25	1.19
CT emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0
Total emission rate (lb/hr) [a + b]	10.3	10.3	10.2	10.2
(lb/mmBtu, HHV)	0.0081	0.0083	0.0085	0.0089
Sulfur Dioxide				
SO ₂ (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO ₂ /lb S)/100				
Fuel use (cf/hr)	1,154,037	1,117,062	1,082,231	1,029,181
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO ₂ /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	6.6	6.4	6.2	5.9
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd @ 15% O ₂) x {[20.9 x (1-Moisture (%)/100) - Oxygen, dry(%)] x 2116.8 lb/ft ² x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT / DB, ppmvd @15% O ₂	9	9	9	9
Moisture (%)	7.21	7.97	8.62	9.45
Oxygen (%)	12.99	12.90	12.83	12.80
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
CT/DB Emission rate (lb/hr)	38.7	37.5	36.2	34.5
CT emission rate, ppmvd @ 15% O ₂	9	9	9	9
CT emission rate (lb/hr)	38.70	37.46	36.25	34.49
HRSG Stack, ppmvd @ 15% O ₂	2.5	2.5	2.5	2.5
HRSG Stack emission rate (lb/hr)	10.8	10.4	10.1	9.6
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft ² x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	9	9	9	9
Moisture (%)	7.21	7.97	8.62	9.45
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525

Table A-6. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F	59 °F	75 °F	95 °F
	Case 16	Case 15	Case 14	Case 13
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
HRSG Exhaust Temperature (°F)	175	178	175	182
Emission rate (lb/hr)- provided	20.1	19.5	19.0	18.3
<u>Volatile Organic Compounds</u>				
$\text{VOCs (lb/hr)} = \text{VOC(ppmvd)} \times [1 - \text{Moisture}(\%)/100] \times 2116.8 \text{ lb/ft}^3 \times \text{Volume flow (acfm)} \times$ $16 \text{ (mole. wgt as methane)} \times 60 \text{ min/hr} / [1545 \times (\text{CT temp. (°F)} + 460^\circ\text{F}) \times 1,000,000 \text{ (adj. for ppm)}]$				
Basis, ppmvw	1.4	1.4	1.4	1.4
Moisture (%)	7.21	7.97	8.62	9.45
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
HRSG Exhaust Temperature (°F)	175	175	175	175
Emission rate (lb/hr)- provided	1.79	1.74	1.69	1.63
<u>Sulfuric Acid Mist</u>				
$\text{Sulfuric Acid Mist (lb/hr)} = \text{SO}_2 \text{ emission (lb/hr)} \times \text{Conversion to H}_2\text{SO}_4 \text{ (% by weight)/100}$				
CT SO ₂ emission rate (lb/hr) - provided	6.6	6.4	6.2	5.9
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10	10
DB SO ₂ emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H ₂ SO ₄ (%) - provided	20	20	20	20
Emission rate (lb/hr)- calculated	0.66	0.64	0.62	0.59
<u>Lead</u>				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-7. Design Information and Stack Parameters for the FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Peak

Parameter	Turbine Inlet Temperature			
	35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
Combustion Turbine Performance				
Net power output (MW)	190.3	182.44	174.64	165.54
Net heat rate (Btu/kWh, LHV)	9,080	9,210	9,330	9,482
(Btu/kWh, HHV)	10,079	10,223	10,356	10,525
Heat Input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
(MMBtu/hr, HHV)	1,918	1,865	1,809	1,742
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,713,000	3,558,000	3,478,000	3,356,000
- provided	3,713,000	3,558,000	3,478,000	3,356,000
Temperature (°F)	1,109	1,130	1,145	1,158
Moisture (% Vol.)	7.74	8.84	9.61	10.73
Oxygen (% Vol.)	12.39	12.15	12.01	11.81
Molecular Weight	28.48	28.36	28.27	28.15
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	82,933	80,648	78,205	75,335
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft ³)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,851,839	1,800,825	1,746,274	1,682,185
HRSG Stack				
HRSG - Stack Height (ft)	131	131	131	131
Diameter (ft)	19	19	19	19
CT Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,713,000	3,558,000	3,478,000	3,356,000
Temperature (°F)	1,109	1,130	1,145	1,158
Molecular weight	28.48	28.36	28.27	28.15
Volume flow (acfm)- calculated	2,488,641	2,426,858	2,402,002	2,346,741
(ft ³ /s)- calculated	41,477	40,448	40,033	39,112
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	109.1	106.4	105.3	102.9
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [(diameter) ² / 4] x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,713,000	3,558,000	3,478,000	3,356,000
HRSG Stack Temperature (°F)	205	205	207	204
Molecular weight	28.48	28.36	28.27	28.15
CT volume flow (acfm)	1,055,240	1,014,759	998,327	962,538
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	62.0	59.7	58.7	56.6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2000.

Table A-8. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Peak

Parameter	Turbine Inlet Temperature			
	35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
<u>Particulate from CT and SCR</u>				
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only				
a. PM ₁₀ (front half) (lb/hr)				
CT- provided	9.0	9.0	9.0	9.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only = Sulfur trioxide from conversion				
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) x conversion of SO ₂ to SO ₃ x lb SO ₃ /lb SO ₂ x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x lb (NH ₄) ₂ SO ₄ / lb SO ₃				
SO ₂ emission rate (lb/hr)- calculated	10.6	10.3	10.0	9.6
Conversion (%) from SO ₂ to SO ₃	9.8	9.8	9.8	9.8
MW SO ₃ / SO ₂ (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100	100
MW (NH ₄) ₂ SO ₄ / SO ₃ (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.14	2.08	2.02	1.94
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0
Total HRSG stack emission rate (lb/hr) [a + b]	11.1	11.1	11.0	10.9
(lb/mmBtu, HHV)	0.0056	0.0057	0.0058	0.0060
<u>Sulfur Dioxide</u>				
SO ₂ (lb/hr) = Natural gas (scf/hr) x sulfur content (gr/100 scf) x 1 lb/7000 gr x (lb SO ₂ /lb S) /100				
Fuel use (cf/hr)	1,851,839	1,800,825	1,746,274	1,682,185
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO ₂ /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	10.6	10.3	10.0	9.6
<u>Nitrogen Oxides</u>				
NOx (lb/hr) = NOx (ppmvd @ 15% O ₂) x {[20.9 x (1-Moisture (%)/100) - Oxygen, dry(%)] x 2116.8 lb/ft ² x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @ 15% O ₂	15	15	15	15
Moisture (%)	7.74	8.84	9.61	10.73
Oxygen (%)	12.39	12.15	12.01	11.81
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
CT/DB Emission rate (lb/hr)	105.1	101.3	99.0	95.5
CT emission rate, ppmvd @ 15% O ₂	15	15	15	15
CT emission rate (lb/hr)	105.1	101.3	99.0	95.5
HRSG Stack, ppmvd @ 15% O ₂	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	17.5	16.9	16.5	15.9
<u>Carbon Monoxide</u>				
CO (lb/hr) = CO (ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft ² x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	15	15	15	15
Basis, ppmvd @ 15% O ₂ - calculated	11.85	11.69	11.62	11.54
Moisture (%)	7.74	8.84	9.61	10.73

Table A-8. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Peak

Parameter	Turbine Inlet Temperature			
	35 °F	59 °F	75 °F	95 °F
	Case 20	Case 19	Case 18	Case 17
Oxygen (%)	12.39	12.15	12.01	11.81
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
HRSG Exhaust Temperature (°F)	205	205	207	204
Emission rate (lb/hr)- provided	50.5	48.0	46.7	44.7
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%) / 100] x 2116.8 lb/ft ³ x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	1.4	1.4	1.4	1.4
Basis, ppmvd @ 15% O ₂ - calculated	1.2	1.2	1.2	1.2
Moisture (%)	7.74	8.84	9.61	10.73
Oxygen (%)	12.39	12.15	12.01	11.81
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
HRSG Exhaust Temperature (°F)	205	205	207	204
Emission rate (lb/hr)- provided	2.69	2.56	2.49	2.38
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr) = SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight) / 100				
CT SO ₂ emission rate (lb/hr) - provided	10.6	10.3	10.0	9.6
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10	10
DB SO ₂ emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H ₂ SO ₄ (%) - provided	20	20	20	20
Emission rate (lb/hr)- calculated	1.06	1.03	1.00	0.96
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-9. Design Information and Stack Parameters for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
Combustion Turbine Performance				
Net power output (MW)	189.1	180.4	172.5	172.5
Net heat rate (Btu/kWh, LHV)	10,019	10,037	10,101	9,486
(Btu/kWh, HHV)	10,620	10,639	10,707	10,056
Heat Input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
(MMBtu/hr, HHV)	2,008	1,919	1,847	1,735
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,367	18,367	18,367	18,367
(Btu/lb, HHV)	19,469	19,469	19,469	19,469
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,862,000	3,683,000	3,552,000	3,376,000
- provided	3,862,000	3,683,000	3,552,000	3,376,000
Temperature (°F)	1,074	1,098	1,113	1,131
Moisture (% Vol.)	10.6	11.21	11.68	12.18
Oxygen (% Vol.)	11.19	11.06	11.00	11.00
Molecular Weight	28.39	28.33	28.27	28.21
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
Heat content (Btu/lb, LHV)	18,367	18,367	18,367	18,367
Fuel usage (lb/hr)- calculated	103,147	98,584	94,871	89,100
HRSG Stack				
HRSG - Stack Height (ft)	131	131	131	131
Diameter (ft)	19	19	19	19
CT Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,862,000	3,683,000	3,552,000	3,376,000
Temperature (°F)	1,074	1,098	1,113	1,131
Molecular weight	28.39	28.33	28.27	28.21
Volume flow (acfm)- calculated	2,538,306	2,464,273	2,403,828	2,316,007
(ft³/s)- calculated	42,305	41,071	40,064	38,600
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	111.3	108.0	105.4	101.5
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [(diameter)² / 4] x 3.14159 / 60 sec/min				
Mass flow (lb/hr)	3,862,000	3,683,000	3,552,000	3,376,000
HRSG Stack Temperature (°F)	297	295	294	294
Molecular weight	28.39	28.33	28.27	28.21
CT volume flow (acfm)	1,252,275	1,193,859	1,151,484	1,096,864
(ft³/s)- calculated	20,871	19,898	19,191	18,281
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	73.6	70.2	67.7	64.5

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2000 - CT Performance Data.

Table A-10. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
<u>Particulate from CT and SCR</u>				
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only				
a. PM ₁₀ (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)				
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) x conversion of SO ₂ to SO ₃ x lb SO ₃ /lb SO ₂ x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x lb (NH ₄) ₂ SO ₄ / lb SO ₃				
SO ₂ emission rate (lb/hr)- calculated	3.1	3.0	2.8	2.7
Conversion (%) from SO ₂ to SO ₃	9.8	9.8	9.8	9.8
MW SO ₃ / SO ₂ (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100	100
MW (NH ₄) ₂ SO ₄ / SO ₃ (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.63	0.60	0.58	0.54
CT emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	17.6	17.6	17.6	17.5
(lb/mmBtu, HHV)	0.0088	0.0092	0.0095	0.0101
<u>Sulfur Dioxide</u>				
SO ₂ (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO ₂ /lb S) /100				
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	103,147	98,584	94,871	89,100
lb SO ₂ / lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	3.1	3.0	2.8	2.7
<u>Nitrogen Oxides</u>				
NOx (lb/hr) = NOx (ppmvd @ 15% O ₂) x {[20.9 x (1-Moisture (%)/100) - Oxygen, dry(%)] x 2116.8 lb/ft ³ x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O ₂	42	42	42	42
Moisture (%)	10.6	11.21	11.68	12.18
Oxygen (%)	11.19	11.06	11.00	11.00
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
CT/DB Emission rate (lb/hr)	333.8	319.2	306.8	288.2
CT emission rate, ppmvd @ 15% O ₂	42	42	42	42
CT emission rate (lb/hr)	333.8	319.2	306.8	288.2
HRSG Stack, ppmvd @ 15% O ₂	10	10	10.0	10.0
HRSG Stack Emission rate (lb/hr)	79.5	76.0	73.1	68.6
<u>Carbon Monoxide</u>				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft ³ x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	10.6	11.21	11.68	12.18
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007

Table A-10. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
HRSG Exhaust Temperature (°F)	297	295	294	294
Emission rate (lb/hr)- provided	68.1	64.7	62.1	58.9
<u>Volatile Organic Compounds</u>				
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft ² x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Basis, ppmvd	3.91	3.94	3.96	3.99
Basis, ppmvd @ 15% O ₂	2.76	2.75	2.77	2.81
Moisture (%)	10.60	11.21	11.68	12.18
Oxygen (%)	11.19	11.06	11.00	11.00
Oxygen (%-dry)	12.52	12.46	12.45	12.53
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
Emission rate (lb/hr)- provided	7.62	7.28	7.04	6.70
<u>Sulfuric Acid Mist</u>				
Sulfuric Acid Mist (lb/hr)= SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight)/100				
CT SO ₂ emission rate (lb/hr) - provided	3.1	3.0	2.8	2.7
CT Conversion to H ₂ SO ₄ (% by weight) - provided	20	20	20	20
DB SO ₂ emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H ₂ SO ₄ (%) - provided	20	20	20	20
Emission rate (lb/hr)- calculated	0.62	0.59	0.57	0.53
<u>Lead</u>				
Lead (lb/hr) = Basis (lb/10 ¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10 ¹² Btu				
Emission Rate Basis (lb/10 ¹² Btu)	14	14	14	14
Emission rate (lb/hr)	0.0265	0.0253	0.0244	0.0229

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-11. Design Information and Stack Parameters for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
Combustion Turbine Performance				
Net power output (MW)	141.5	135.0	129.1	119.1
Net heat rate (Btu/kWh, LHV)	10,654	10,730	10,866	11,138
(Btu/kWh, HHV)	11,293	11,373	11,518	11,807
Heat Input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
(MMBtu/hr, HHV)	1,598	1,536	1,487	1,406
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,024,000	2,936,000	2,871,000	2,758,000
- provided	3,024,000	2,936,000	2,871,000	2,758,000
Temperature (°F)	1,121	1,137	1,149	1,166
Moisture (% Vol.)	10.23	10.68	11.06	11.54
Oxygen (% Vol.)	11.22	11.21	11.22	11.25
Molecular Weight	28.44	28.38	28.33	28.27
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	81,993	78,784	76,298	72,154
HRSG Stack				
HRSG - Stack Height (ft)	131	131	131	131
Diameter (ft)	19	19	19	19
CT Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F) + 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,024,000	2,936,000	2,871,000	2,758,000
Temperature (°F)	1,121	1,137	1,149	1,166
Molecular weight	28.44	28.38	28.33	28.27
Volume flow (acfm)- calculated	2,045,011	2,009,479	1,983,445	1,929,486
(ft ³ /s)- calculated	34,084	33,491	33,057	32,158
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	89.7	88.1	87.0	84.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,024,000	2,936,000	2,871,000	2,758,000
HRSG Stack Temperature (°F)	271	274	276	278
Molecular weight	28.44	28.38	28.33	28.27
CT volume flow (acfm)	945,414	923,329	907,281	875,151
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	55.6	54.3	53.3	51.4

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft²

Source: GE, 2000

Table A-12. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
Particulate from CTand SCR				
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only				
a. PM ₁₀ (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)				
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) x conversion of SO ₂ to SO ₃ x lb SO ₃ /lb SO ₂ x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x lb (NH ₄) ₂ SO ₄ / lb SO ₃				
SO ₂ emission rate (lb/hr)- calculated	2.5	2.4	2.3	2.2
Conversion (%) from SO ₂ to SO ₃	9.8	9.8	9.8	9.8
MW SO ₃ / SO ₂ (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100	100
MW (NH ₄) ₂ SO ₄ / SO ₃ (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.50	0.48	0.46	0.44
CT emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	17.5	17.5	17.5	17.4
(lb/mmBtu, HHV)	0.0108	0.0112	0.0116	0.0122
Sulfur Dioxide				
SO ₂ (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO ₂ /lb S) /100				
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	81,993	78,784	76,298	72,154
lb SO ₂ / lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	2.5	2.4	2.3	2.2
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd @ 15% O ₂) x {[20.9 x (1-Moisture (%)/100) - Oxygen, dry(%)] x 2116.8 lb/ft ² x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @ 15% O ₂	42	42	42	42
Moisture (%)	10.23	10.68	11.06	11.54
Oxygen (%)	11.22	11.21	11.22	11.25
Turbine Flow (acfm)	2,045,011	2,009,479	1,983,445	1,929,486
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
CT emission rate (lb/hr)	262.6	252.6	244.5	231.2
CT emission rate, ppmvd @ 15% O ₂	42	42	42	42
CT emission rate (lb/hr)	262.6	252.6	244.5	231.2
HRSG Stack, ppmvd @ 15% O ₂	10	10	10.0	10.0
HRSG Stack Emission rate (lb/hr)	62.5	60.1	58.2	55.0
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft ² x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	10.23	10.68	11.06	11.54
Turbine Flow (acfm)	2,045,011	2,009,479	1,983,445	1,929,486
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166

Table A-12. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
HRSG Exhaust Temperature (°F)	271	274	276	278
Emission rate (lb/hr)- provided	53.5	51.7	50.5	48.3
<u>Volatile Organic Compounds</u>				
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft ³ x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Moisture (%)	10.23	10.68	11.06	11.54
Turbine Flow (acfm)	11.22	11.21	11.22	11.25
Turbine Exhaust Temperature (°F)	2,045,011	2,009,479	1,983,445	1,929,486
HRSG Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
Emission rate (lb/hr)- provided	5.95	5.79	5.67	5.46
<u>Sulfuric Acid Mist</u>				
Sulfuric Acid Mist (lb/hr)= SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight)/100				
CT SO ₂ emission rate (lb/hr) - provided	2.5	2.4	2.3	2.2
CT Conversion to H ₂ SO ₄ (% by weight) - provided	20	20	20	20
DB SO ₂ emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H ₂ SO ₄ (%) - provided	20	20	20	20
Emission rate (lb/hr)- calculated	0.49	0.47	0.46	0.43
<u>Lead</u>				
Lead (lb/hr) = Basis (lb/10 ¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10 ¹² Btu.				
Emission Rate Basis (lb/10 ¹² Btu)	14	14	14	14
Emission rate (lb/hr)	0.0211	0.0203	0.0196	0.0186

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-13. Design Information and Stack Parameters for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
Combustion Turbine Performance				
Net power output (MW)	93.8	89.5	85.6	78.9
Net heat rate (Btu/kWh, LHV)	12,685	12,867	13,069	13,453
(Btu/kWh, HHV)	13,446	13,639	13,853	14,260
Heat Input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
(MMBtu/hr, HHV)	1,261	1,221	1,186	1,125
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,487,000	2,435,000	2,389,000	2,323,000
- provided	2,487,000	2,435,000	2,389,000	2,323,000
Temperature (°F)	1,168	1,182	1,193	1,200
Moisture (% Vol.)	9.29	9.77	10.17	10.6
Oxygen (% Vol.)	11.76	11.76	11.77	11.86
Molecular Weight	28.51	28.46	28.40	28.34
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	64,720	62,637	60,847	57,736
HRSG Stack				
HRSG - Stack Height (ft)	131	131	131	131
Diameter (ft)	19	19	19	19
CT Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1.545 x (Temp. (°F) + 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,487,000	2,435,000	2,389,000	2,323,000
Temperature (°F)	1,168	1,182	1,193	1,200
Molecular weight	28.51	28.46	28.40	28.34
Volume flow (acfm)- calculated	1,727,369	1,709,200	1,691,211	1,654,983
(ft³/s)- calculated	28,789	28,487	28,187	27,583
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	75.7	74.9	74.2	72.6
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² / 4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	2,487,000	2,435,000	2,389,000	2,323,000
HRSG Stack Temperature (°F)	256	259	264	268
Molecular weight	28.51	28.46	28.40	28.34
CT volume flow (acfm)	759,385	748,426	740,736	725,501
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	44.6	44.0	43.5	42.6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2000

Table A-14. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
<u>Particulate from CTand SCR</u>				
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only				
a. PM ₁₀ (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17.0
b. PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)				
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) x conversion of SO ₂ to SO ₃ x lb SO ₃ /lb SO ₂ x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x lb (NH ₄) ₂ SO ₄ / lb SO ₃				
SO ₂ emission rate (lb/hr)- calculated	1.9	1.9	1.8	1.7
Conversion (%) from SO ₂ to SO ₃	9.8	9.8	9.8	9.8
MW SO ₃ / SO ₂ (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100	100
MW (NH ₄) ₂ SO ₄ / SO ₃ (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.39	0.38	0.37	0.35
CT emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	17.4	17.4	17.4	17.4
(lb/mmBtu, HHV)	0.0138	0.0142	0.0146	0.0154
<u>Sulfur Dioxide</u>				
SO ₂ (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO ₂ /lb S) /100				
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	64,720	62,637	60,847	57,736
lb SO ₂ / lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	1.9	1.9	1.8	1.7
<u>Nitrogen Oxides</u>				
NOx (lb/hr) = NOx (ppmvd @ 15% O ₂) x [(20.9 x (1-Moisture (%)/100) - Oxygen, dry(%)) x 2116.8 lb/ft ³ x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O ₂	42	42	42	42
Moisture (%)	9.29	9.77	10.17	10.6
Oxygen (%)	11.76	11.76	11.77	11.86
Turbine Flow (acfm)	1,727,369	1,709,200	1,691,211	1,654,983
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
CT/DB Emission rate (lb/hr)	205.6	198.9	192.9	183.2
CT emission rate, ppmvd @ 15% O ₂	42	42	42	42
CT emission rate (lb/hr)	205.6	198.9	192.9	183.2
HRSG Stack, ppmvd @ 15% O ₂	10	10	10.0	10.0
HRSG Stack Emission rate (lb/hr)	49.0	47.4	45.9	43.6
<u>Carbon Monoxide</u>				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft ³ x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	9.29	9.77	10.17	10.6
Turbine Flow (acfm)	1,727,369	1,709,200	1,691,211	1,654,983
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200

Table A-14. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F	59 °F	75 °F	95 °F
	Case 36	Case 35	Case 34	Case 33
HRSG Exhaust Temperature (°F)	29	28	28	28
Emission rate (lb/hr)- provided	44.3	43.2	42.3	41.0
<u>Volatile Organic Compounds</u>				
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft ³ x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Moisture (%)	9.29	9.77	10.17	10.60
Turbine Flow (acfm)	11.76	11.76	11.77	11.86
Turbine Exhaust Temperature (°F)	1,727,369	1,709,200	1,691,211	1,654,983
HRSG Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
Emission rate (lb/hr)- provided	4.88	4.79	4.71	4.59
<u>Sulfuric Acid Mist</u>				
Sulfuric Acid Mist (lb/hr)= SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight)/100				
CT SO ₂ emission rate (lb/hr) - provided	1.9	1.9	1.8	1.7
CT Conversion to H ₂ SO ₄ (% by weight) - provided	20	20	20	20
DB SO ₂ emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H ₂ SO ₄ (%) - provided	20	20	20	20
Emission rate (lb/hr)- calculated	0.39	0.38	0.37	0.35
<u>Lead</u>				
Lead (lb/hr) = Basis (lb/10 ¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10 ¹² Btu				
Emission Rate Basis (lb/10 ¹² Btu)	14	14	14	14
Emission rate (lb/hr)	0.0167	0.0161	0.0157	0.0149

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data.

Table A-15. Regulated and Hazardous Air Pollutant Emission Factors and Emissions for FPL Turkey Point Combined-Cycle Expansion Project when Firing Natural Gas

Parameter	Emission Rate (lb/hr) firing Natural Gas for Operating Conditions of Base Load (1)			Natural Gas Maximum Annual Emissions (TPY) (2)		
	Ambient Temperature (°F):			59 °F	59 °F	
	HIR (MMBtu/hr):	59 °F	59 °F w/DB	1	4	
		1,776	2,326	CT/HRSG	CTs/HRSGs	
Sulfuric acid mist		0.98	1.28	1.25	4.7	18.9
<u>HAPs (Section 112(b) of Clean Air Act)</u>						
1,3-Butadiene		0.000764	0.001000	0.000978	0.0037	0.0147
Acetaldehyde		0.0711	0.0931	0.0909	0.3425	1.37
Acrolein		0.0114	0.0149	0.0146	0.0548	0.219
Benzene		0.0213	0.0279	0.0273	0.1027	0.411
Ethylbenzene		0.0568	0.0744	0.0728	0.2740	1.096
Formaldehyde		0.387	0.507	0.496	1.8665	7.47
Naphthalene		0.00231	0.00302	0.00296	0.0111	0.0445
Polycyclic Aromatic Hydrocarbons (PAH)	(3)	0.00391	0.00512	0.00500	0.0188	0.0753
Propylene Oxide		0.0515	0.0675	0.0659	0.2483	0.993
Toluene		0.0586	0.0768	0.0750	0.2825	1.13
Xylene		0.114	0.149	0.146	0.5480	2.19
Antimony		0.0	0.0	0.0	0.00	0.00
Arsenic		0.0	0.0	0.0	0.00	0.00
Beryllium		0.0	0.0	0.0	0.00	0.00
Cadmium		0.0	0.0	0.0	0.00	0.00
Chromium		0.0	0.0	0.0	0.00	0.00
Lead		0.0	0.0	0.0	0.00	0.00
Manganese		0.0	0.0	0.0	0.00	0.00
Mercury		0.0	0.0	0.0	0.00	0.00
Nickel		0.0	0.0	0.0	0.00	0.00
Selenium		0.0	0.0	0.0	0.00	0.00
HAPs (Total)		0.779	1.020	0.997	5.00	15.0

(1) Emissions based on the following emission factors and conversion factors for firing natural gas:

Emission Factors	Value	Reference
Sulfuric acid mist	5 %	Conversion of SO ₂ to SO ₃ in gas turbine
1,3-Butadiene (a)	0.43 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Acetaldehyde	40 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Acrolein	6.4 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Benzene	12 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Ethylbenzene	32 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Formaldehyde	218 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000. Database
Naphthalene	1.3 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)	2.2 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Propylene Oxide (a)	29 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Toluene	33 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000. Database
Xylene	64 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Antimony	0.00E+00	
Arsenic	0.00E+00	
Beryllium	0.00E+00	
Cadmium	0.00E+00	
Chromium	0.00E+00	
Lead	0.00E+00	
Manganese	0.00E+00	
Mercury	0.00E+00	
Nickel	0.00E+00	
Selenium	0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

(2) Annual emissions based on ambient temperature of 59 °F firing natural gas for following hours:

5,880
2,480
400

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

Table A-15a. Maximum Formaldehyde Emissions for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only					
	Turbine Inlet Temperature					
	35 °F Case 8	59 °F	59 °F Case 6	75 °F Case 4	80 °F Peak	95 °F Case 2
Formaldehyde (CH ₂ O) MW =	30					
$\text{CH}_2\text{O (lb/hr)} = \text{CH}_2\text{O (ppmvd@ 15\% O}_2\text{)} \times \{[20.9 \times (1 - \text{Moisture (\%)/100}] - \text{Oxygen, dry(\%)}\} \times 2116.8 \text{ lb/ft}^2 \times \text{Volume flow (acfm)} \times$ $30 \text{ (mole. wgt CH}_2\text{O)} \times 60 \text{ min/hr} / [1545 \times (\text{CT temp. (}^\circ\text{F)} + 460) \times (20.9 - 15) \times 1,000,000 \text{ (adj. for ppm)}]$						
CT, ppmvd @15% O ₂	0.091	0.091	0.091	0.091	0.091	0.091
Moisture (%)	7.56	8.3	8.39	9.04	9.7	9.92
Oxygen (%)	12.6	12.56	12.44	12.36	12.19	12.27
Turbine Flow (acfm)	2,460,544	2,390,425	2,389,462	2,331,000	2,350,164	2,250,314
Turbine Exhaust Temperature (°F)	1,095	1,117	1,116	1,128	1,125	1,143
CT Emission rate (lb/hr)	0.404	0.584	0.387	0.371	0.377	0.350
CT Emission rate (lb/10 ¹² Btu)	217.7		217.7	217.9	218.7	217.9

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data; Golder Associates, 2003

Table A-16. Regulated and Hazardous Air Pollutant Emission Factors and Emissions for FPL FPL Turkey Point Combined-Cycle Expansion Project when Firing Distillate Fuel Oil

Parameter	Emission Rate (lb/hr)		Maximum Annual Emissions (TPY)			
	Firing Distillate Fuel Oil (1)		Distillate Fuel Oil (2)			
	Base Load		Natural Gas (4)			
Ambient Temperature (°F):	59 °F					
HIR (MMBtu/hr):	1,919		1	4	4	4
			CT/HRSG	CTs/HRSGs	CTs/HRSGs	CTs/HRSGs
Sulfuric acid mist	0.6		0.15	0.6	18.9	18.4
<u>HAPs (Section 112(b) of Clean Air Act)</u>						
1,3-Butadiene	0.0307		0.0077	0.0307	0.0147	0.045
Acetaldehyde	0.00		0.00	0.00	1.37	1.3
Acrolein	0.00		0.00	0.00	0.219	0.21
Benzene	0.106		0.0264	0.1056	0.411	0.49
Ethylbenzene	0.00		0.00	0.00	1.096	1.03
Formaldehyde	0.451		0.113	0.451	7.47	7.5
Naphthalene	0.0672		0.0168	0.0672	0.0445	0.109
Polycyclic Aromatic Hydrocarbons (PAH) (3)	0.0768		0.0192	0.0768	0.0753	0.15
Propylene Oxide	0.00		0.00	0.00	0.993	0.94
Toluene	0.00		0.00	0.00	1.13	1.1
Xylene	0.00		0.00	0.00	2.19	2.1
Antimony	0.00		0.00	0.00	0.00	0.0
Arsenic	0.0211		0.00528	0.0211	0.00	0.021
Beryllium	0.000595		0.000149	0.000595	0.00	0.00059
Cadmium	0.00921		0.00230	0.00921	0.00	0.0092
Chromium	0.0211		0.00528	0.0211	0.00	0.021
Lead	0.0269		0.00672	0.0269	0.00	0.027
Manganese	1.52		0.379	1.52	0.00	1.5
Mercury	0.00230		0.000576	0.00230	0.00	0.0023
Nickel	0.00883		0.00221	0.00883	0.00	0.0088
Selenium	0.0480		0.0120	0.0480	0.00	0.048
HAPs (Total)	2.39		0.795	2.39	15.0	16.5

(1) Emissions based on the following emission factors and conversion factors for firing distillate fuel oil:

Emission Factors	Value	Reference
Sulfuric acid mist	5	%; Conversion of SO ₂ to SO ₃ in gas turbine
1,3-Butadiene	(a) 16	lb/10 ¹² Btu; AP-42, Table 3.1-4. EPA 2000
Acetaldehyde	0.0	
Acrolein	0.0	
Benzene	55	lb/10 ¹² Btu; AP-42, Table 3.1-4. EPA 2000
Ethylbenzene	0.0	
Formaldehyde	235	lb/10 ¹² Btu; AP-42, Table 3.1-4. EPA 2000
Naphthalene	35	lb/10 ¹² Btu; AP-42, Table 3.1-4. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)	40	lb/10 ¹² Btu; AP-42, Table 3.1-4. EPA 2000
Propylene Oxide	0.0	
Toluene	0.0	
Xylene	0.0	
Antimony	0.0	
Arsenic	(a) 11	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Beryllium	(a) 0.31	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Cadmium	4.8	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Chromium	11	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Lead	14	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Manganese	790	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Mercury	1.2	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Nickel	(a) 4.6	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000
Selenium	(a) 25	lb/10 ¹² Btu; AP-42, Table 3.1-5. EPA 2000

(a) Based on 1/2 the detection limit; expected emissions are lower.

- (2) Annual emissions based on ambient temperature of 59°F and firing fuel oil at base load for : 500 hours
(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.
(4) Annual emissions based on maximum emissions presented for natural gas-firing
(5) Maximum total annual emissions based on 500 hours of firing fuel and remaining hours firing natural gas.

Table A-16a. Maximum Formaldehyde Emissions for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	CT Only			
	Turbine Inlet Temperature			
	35 °F Case 28	59 °F	75 °F Case 24	95 °F Case 22
<u>Formaldehyde (CH₂O) MW =</u> 30				
$\text{CH}_2\text{O (lb/hr)} = \text{CH}_2\text{O (ppmvd@ 15\% O}_2\text{)} \times \{[20.9 \times (1 - \text{Moisture (\%)/100}] - \text{Oxygen, dry(\%)}\} \times 2116.8 \text{ lb/ft}^2 \times \text{Volume flow (acfm)} \times$ $30 \text{ (mole. wgt CH}_2\text{O)} \times 60 \text{ min/hr} / [1545 \times (\text{CT temp. (°F)} + 460) \times (20.9 - 15) \times 1,000,000 \text{ (adj. for ppm)}]$				
CT, ppmvd @15% O ₂	0.091	0.091	0.091	0.091
Moisture (%)	10.6	11.21	11.68	12.18
Oxygen (%)	11.19	11.06	11.00	11.00
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
CT Emission rate (lb/hr)	0.472	0.451	0.434	0.407
CT Emission rate (lb/10 ¹² Btu)	234.8982	235.0044	234.7377	234.7508

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2000 - CT Performance Data; Golder Associates, 2003

Table A-17. Design Information and Stack Parameters for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NO_x Combustor, Natural Gas, Base Load

Parameter	CT Only	CT with Duct Burner	
	Turbine Inlet Temperature	Turbine Inlet Temperature	
	35 °F Case 8	35 °F w/DB Case 7	80 °F w/DB Peak
Combustion Turbine Performance			
Net power output (MW)	181.64	181.64	164.44
Net heat rate (Btu/kWh, LHV)	9,213	9,213	9440
(Btu/kWh, HHV)	10,227	10,227	10,481
Heat Input (MMBtu/hr, LHV)	1,674	1,674	1552.7
(MMBtu/hr, HHV)	1,858	1,858	1,723
Inlet Fogger	Off	Off	On
Relative Humidity (%)	20	20	
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110
Duct Burner (DB)			
Heat input (MMBtu/hr, HHV)	0	210	360
(MMBtu/hr, LHV)	0	189.2	324.3
CT/DB Exhaust Flow			
Mass Flow (lb/hr)- with no margin	3,706,000	3,714,438.0	3,458,465
- provided	3,706,000		
Temperature (°F)	1,095	1,095	1,125
Moisture (% Vol.)	7.56	8.34	11.72
Oxygen (% Vol.)	12.60	11.74	11.21
Molecular Weight	28.49	28.44	29.73
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,674	1,674	1,553
Heat content (Btu/lb, LHV)	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	80,322	80,322	74,524
Heat content (Btu/cf, LHV)- assumed	933	933	933
Fuel density (lb/ft ³)	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,792,892	1,792,892	1,663,474
Fuel Usage - Duct Burner Only			
Fuel usage (lb/hr)- calculated	0	9,080	15,566
Fuel usage (cf/hr)- calculated	0	202,686	347,463
HRSG Stack			
CT/Bypass-Stack height (ft)	80	80	80
Diameter (ft)	22	22	22
HRSG - Stack Height (ft)	131	131	131
Diameter (ft)	19	19	19
CT Flow Conditions			
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F) + 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	3,706,000	NA	NA
Temperature (°F)	1,095	NA	NA
Molecular weight	28.49	NA	NA
Volume flow (acfm)- calculated	2,460,544	NA	NA
(ft ³ /s)- calculated	41,009	NA	NA
Diameter (ft)	22	NA	NA
Velocity (ft/sec)- calculated	107.9	NA	NA
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [(diameter) ² / 4] x 3.14159 / 60 sec/min			
Mass flow (lb/hr)	3,706,000	3,714,438	3,458,465
HRSG Stack Temperature (°F)	203	189	188
Molecular weight	28.49	28.44	29.73
Volume flow (acfm)	1,048,619	1,030,566	916,879
Diameter (ft)	19	19	19
Velocity (ft/sec)- calculated	61.6	60.6	53.9

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft²

Source: GE, 2000 - CT Performance Data; Golder Associates, 2001 - DB Calculations

Table A-18. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only	CT with Duct Burner	
	Turbine Inlet Temperature	Turbine Inlet Temperature	
	35 °F Case 8	35 °F w/DB Case 7	80 °F w/DB Peak
<u>Particulate from CT, DB, and SCR</u>			
Total PM ₁₀ = PM ₁₀ (front half) + PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only			
a. PM ₁₀ (front half) (lb/hr)			
CT- provided	9.0	9.0	9.0
DB (lb/hr) - calculated	0.0	1.1	1.8
Total CT/DB emission rate (lb/hr)	9.0	10.1	10.8
b. PM ₁₀ ((NH ₄) ₂ SO ₄) from SCR only = Sulfur trioxide from conversion of SO ₂ converts to ammonium sulfate (= PM ₁₀)			
Particulate from conversion of SO ₂ = SO ₂ emissions (lb/hr) x conversion of SO ₂ to SO ₃ x lb SO ₃ /lb SO ₂ x conversion of SO ₃ to (NH ₄) ₂ SO ₄ x lb (NH ₄) ₂ SO ₄ / lb SO ₃			
SO ₂ emission rate (lb/hr)- calculated	10.2	11.4	11.5
Conversion (%) from SO ₂ to SO ₃	9.8	9.8	9.8
MW SO ₃ / SO ₂ (80/64)	1.3	1.3	1.3
Conversion (%) from SO ₃ to (NH ₄) ₂ (SO ₄)	100	100	100
MW (NH ₄) ₂ SO ₄ / SO ₃ (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.07	2.30	2.32
Total CT emission rate (lb/hr) [a]	9.0	NA	NA
Total HRSG stack emission rate (lb/hr) [a + b] (lb/mmBtu, HHV)	11.1 0.0060	12.4 0.0060	13.1 0.0063
<u>Sulfur Dioxide</u>			
SO ₂ (lb/hr) = Natural gas (scf/hr) x sulfur content (gr/100 scf) x 1 lb/7000 gr x (lb SO ₂ /lb S) /100			
Fuel use (cf/hr)	1,792,892	1,995,579	2,010,937
Sulfur content (grains/ 100 cf)	2	2	2
lb SO ₂ /lb S (64/32)	2	2	2
HRSG stack emission rate (lb/hr)	10.2	11.4	11.5
<u>Nitrogen Oxides</u>			
NO _x (lb/hr) = NO _x (ppmvd @ 15% O ₂) x {[20.9 x (1-Moisture (%)/100) - Oxygen, dry(%)] x 2116.8 lb/ft ³ Volume flow (acfm) x 46 (mole. wgt NO _x) x 60 min/hr / [1545 x (CT temp. (°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT/DB, ppmvd @ 15% O ₂	9	9.5	13.2
Moisture (%)	7.56	8.34	11.72
Oxygen (%)	12.6	11.74	11.21
Turbine Flow (acfm)	2,460,544	2,470,753	2,394,697
Turbine Exhaust Temperature (°F)	1,095	1,095	1,125
CT/DB Emission rate (lb/hr)	61.3	78.1	105.0
HRSG Stack emission rate, ppmvd @ 15% O ₂	2.5	2.5	2.5
HRSG Stack emission rate (lb/hr)	17.0	20.6	19.9
<u>Carbon Monoxide</u>			
CO (lb/hr) = CO (ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft ³ Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp. (°F) + 460) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	9	11.7	13.9
Basis, ppmvd @ 15% O ₂ - calculated	7.30	8.5	10.0
Moisture (%)	7.56	8.34	11.72
Oxygen (%)	12.60	11.74	11.21

Table A-18. Maximum Emissions for Criteria Pollutants for FPL Turkey Point Combined-Cycle Expansion Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only	CT with Duct Burner	
	Turbine Inlet Temperature	Turbine Inlet Temperature	
	35 °F Case 8	35 °F w/DB Case 7	80 °F w/DB Peak
Turbine Flow (acfm)	2,460,544	2,470,753	2,394,697
Turbine Exhaust Temperature (°F)	1,095	1,095	1,125
CT/DB Emission rate (lb/hr) (corrected 3/3/2003)	30.3	38.7	42.1
Emission rate (lb/hr)	30.3	38.7	42.1
<u>Volatile Organic Compounds</u>			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%) / 100] x 2116.8 lb/hr x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw			
Basis, ppmvd	1.5	2.0	2.4
Basis, ppmvd @ 15% O2 - calculated	1.3	1.6	1.9
Moisture (%)	7.56	8.34	11.72
Oxygen (%) wet	12.60	11.74	11.21
Oxygen (%) dry			
Turbine Flow (acfm)	2,460,544	2,470,753	2,394,697
Turbine Exhaust Temperature (°F)	1,095	1,095	1,125
CT/DB Emission rate (lb/hr)	2.89	3.73	4.08
HRSG Stack Emission rate (lb/hr)	2.89	3.73	4.08
<u>Sulfuric Acid Mist</u>			
Sulfuric Acid Mist (lb/hr) = SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight) / 100			
CT SO ₂ emission rate (lb/hr) - provided	10.2	10.2	9.5
CT Conversion to H ₂ SO ₄ (% by weight) - provided	10	10	10
DB SO ₂ emission rate (lb/hr) - provided	0	1.2	2.0
DB Conversion to H ₂ SO ₄ (%) - provided	20	20	20
HRSG Stack Emission rate (lb/hr)	1.02	1.26	1.35
<u>Lead</u>			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; Q= oxygen.

Source: GE, 2000 - CT Performance Data; Golder Associates, 2001 - DB Calculations

Table A-19. GAS FIRING - COMBINED CYCLE (Emissions are per CT; 4-CT/HRSG in Project)
CALPUFF Emissions 80 °F Inlet Fogged Power Augmentation (360 MMBtu/hr)

PM	Source	Rate (lb/hr)	Soil	Elemental Carbon (EC)	H ₂ SO ₄	Organic
Filterable	CT	9	9	0		
	DB	1.8	0	1.8		
	SCR	2.26	2.26			
Condensible	CT	3.5			1.12	2.38
	DB	1.8			0.23	1.57
Total PM ₁₀		18.36	11.26	1.8	1.35	3.95
		100.00%	61.33%	9.80%	7.35%	21.51%
Extinction Factor			1.00	10.00	6.00	4.00
Total Relative Extinction Factor		53.16	11.26	18.00	8.10	15.80
		100.00%	21.18%	33.86%	15.24%	29.72%

Notes: DB emissions based on 0.005 lb/MMBtu for both filterable and condensible.

CT filterable is soil based on GE data and information; GE stated that no PM from combustion process (i.e., no EC).

DB filterable assumed to be EC.

H₂SO₄ based on direct calculation and apportioned based on heat input.

GE emission estimates:

	Average Rate (lb/hr)
Filterable (Front Half)	4.8
Condensible (Back Half)	2.8
Total (Front and Back Half)	7.6

Other Pollutants Modeled	Rate (lb/hr)	
	1 CT	4 CTs
SO ₂ :	11.5	46.0
NO _x :	19.9	79.6

Stack Parameters for Modeling

Temperature	°F	188
Velocity	ft/s	53.9
Diameter	ft	19
Height	ft	131

Particle Size Distribution (NPS Nov. 2002)

Species Name	Geometric Mass (microns)	Cumulative Size Distribution (%)	Distribution by Category (%)	Emission Rate (lb/hr)	
				1 CT	4 CTs
PM (Total PM ₁₀ - H ₂ SO ₄)			100	17.0	68.0
PM0005	0.05	15	15	2.55	10.21
PM0010	0.10	40	25	4.25	17.01
PM0015	0.15	63	23	3.91	15.65
PM0020	0.20	78	15	2.55	10.21
PM0025	0.25	89	11	1.87	7.48
PM0100	1.00	100	11	1.87	7.48

Table A-20. OIL FIRING - COMBINED CYCLE (Emissions are per CT; 4 CT/HRS in Project)
CALPUFF Emissions 35°F Inlet Baseload

PM	Source	Rate (lb/hr)	Soil	Elemental Carbon (EC)	H ₂ SO ₄	Organic
Filterable	CT	17	12.2	4.8		
	DB	0	0	0		
	SCR	0.63	0.63			
Condensable	CT	4.62			0.62	4.00
	DB	0				0.00
Total PM ₁₀		22.25	12.83	4.8	0.62	4
		100.00%	57.66%	21.57%	2.79%	17.98%
Extinction Factor			1.00	10.00	6.00	4.00
Total Relative Extinction Factor		80.55	12.83	48.00	3.72	16.00
		100.00%	15.93%	59.59%	4.62%	19.86%

Notes: CT filterable is soil based on GE data and information; 4.8 lb/hr is 50% of average front-half test data.

Condensable based on GE average rate and subtracting the effect of 0.05% sulfur fuel.

H₂SO₄ based on direct calculation and apportioned based on heat input.

GE emission estimates:

	Average Rate (lb/hr)
Filterable (Front Half)	9.5
Condensable (Back Half)	4
Total (Front and Back Half)	13.5

14 lb/hr minus sulfate of 10 lb/hr

Other Pollutants Modeled	Rate (lb/hr)	
	1 CT	4 CTs
SO ₂ :	3.1	12.4
NO _x :	79.5	318

Stack Parameters for Modeling

Temperature	°F	297
Velocity	ft/s	73.6
Diameter	ft	19
Height	ft	131

Particle Size Distribution

Species Name	Geometric Mass (microns)	Cumulative Size Distribution (%)	Distribution by Category (%)	Emission Rate (lb/hr)	
				1 CT	4 CTs
PM (Total PM ₁₀ - H ₂ SO ₄)			100	21.63	86.5
PM0005	0.05	16	16	3.46	13.84
PM0010	0.10	48	32	6.92	27.69
PM0015	0.15	72	24	5.19	20.76
PM0020	0.20	85	13	2.81	11.25
PM0025	0.25	93	8	1.73	6.92
PM0100	1.00	100	7	1.51	6.06



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September 19, 2003

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Tel: 561-694-4000

SUBJECT: Expected Particulate Matter Emissions: GE 7FA DLN Combustion Turbines

Dear Mr. Gnecco:

In response to your request for expected PM-10 emissions data for GE 7FA DLN gas turbines, enclosed is a summary of the data gathered to date on our 7FA units with liquid fuel-firing and water injection for NOx control. All of the emissions data included in this summary must be considered as estimates only and are not guarantees under any condition.

Only limited data are available in-house for water injected liquid fuel-fired 7FA units. The data presented in this transmittal correspond to stack measurements for 7 tests on 3 units located at different sites and operating at base load conditions. Both front and back half emissions were measured using EPA Method 5 and 202, respectively. Each test consisted of 3 runs each, with exception of Test 1 where the back half emissions were measured for only 2 of the 3 runs.

From the enclosed summary, it is observed that PM-10 emissions (front and back half) for liquid fuel operations range from 4 to 37 lbs/hr with an average of 24 lbs/hr and a standard deviation of 9 lbs/hr. Front half emissions ranged from 1 to 20 lbs/hr with an average of 10 lbs/hr and a standard deviation of 4 lbs/hr, and back half emissions ranged from 3 to 21 lbs/hr with an average of 14 lbs/hr and a standard deviation of 6 lbs/hr. It is assumed that back half emissions include sulfur mist emissions corresponding to an 0.05% by wt. Sulfur fuel. The 0.05% by wt. sulfur can contribute as much as 10 lbs/hr of sulfur mist emissions at base load operating conditions. With a 0.0015% by wt. sulfur fuel, the expected corresponding sulfur mist contribution to total PM-10 emissions is less than 1 lb/hr.

As evident in the summary data, PM-10 emissions vary widely although they reflect emissions from equivalent units (same combustor and size) firing similar liquid fuels. Additionally, the combustion process in gas turbines is highly efficient, complete and repeatable process with a very specific range of allowable operating conditions. Therefore, it is assumed that the variation in the data is largely due to non-combustion factors such as fuel and ambient air impurities and measurement artifacts. For these reasons, it is GE's policy to keep the PM-10 emissions guarantee for 7FA liquid-fuel operations to 34 lbs/hr excluding sulfur compounds. Additionally

in the case of non-compliance, GE's only remedy in meeting the PM-10 emissions guarantee is to re-test the unit after an extended period of operation (minimum of 300 hrs). To date, this has proven to be highly successful, which further reflect that PM-10 emissions variations from gas turbines are mostly due to non-combustion factors.

I hope you find this summary helpful. Please note that the summary data presented herein are subject to change as additional field data are gathered. If you have any questions, fell free to call me at (518) 385-5368.

Sincerely,

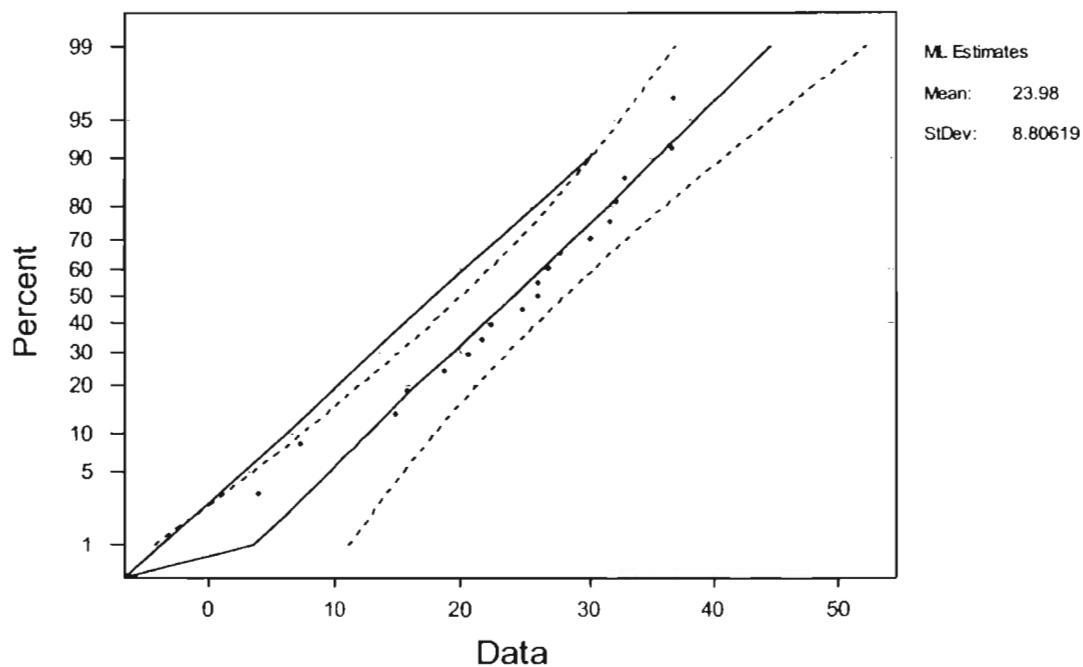
A handwritten signature in black ink, appearing to read 'B. Richani', with a stylized flourish at the end.

Brahim Richani, Ph.D.
Manager

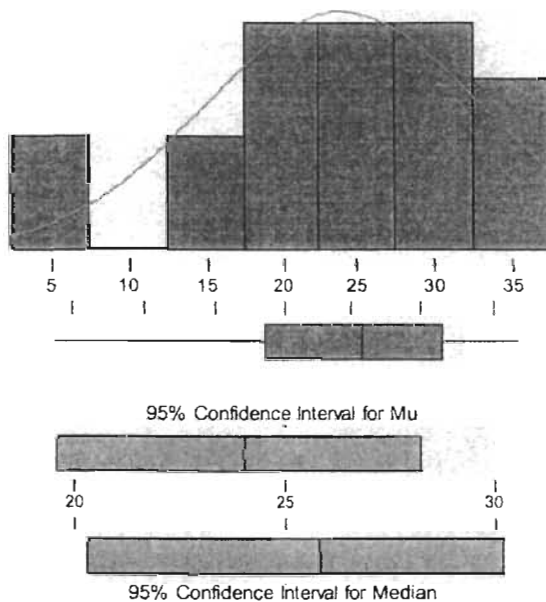
Enclosure

cc: John Almstead – GE
Frank Brooks – GE
Joel Chalfin – GE
Jeanne Beres – GE
Jim Dryzmala – GE

Normal Probability Plot for FrontandBack



Descriptive Statistics



Variable: FrontandBack

Anderson-Darling Normality Test

A-Squared: 0.301
P-Value: 0.545

Mean 23.9800
StDev 9.0475
Variance 81.8572
Skewness -7.1E-01
Kurtosis 0.202106
N 19

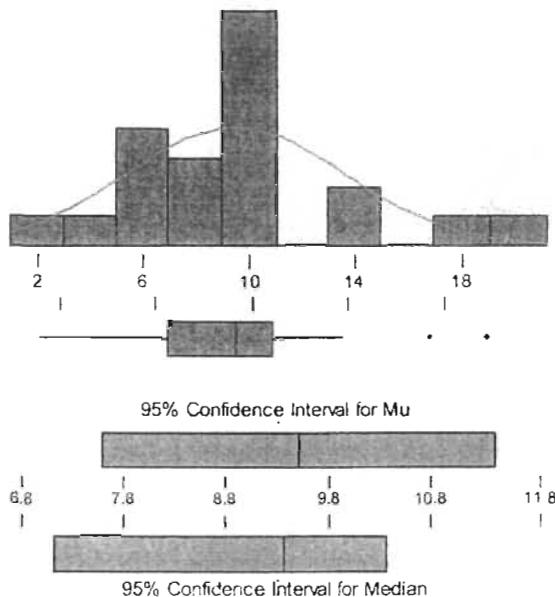
Minimum 3.7900
1st Quartile 18.8200
Median 25.9000
3rd Quartile 31.5400
Maximum 36.7400

95% Confidence Interval for Mu
19.6192 28.3408

95% Confidence Interval for Sigma
6.8364 13.3797

95% Confidence Interval for Median
20.3493 30.2094

Descriptive Statistics



Variable: Front Half

Anderson-Darling Normality Test

A-Squared: 0.548
 P-Value: 0.139

Mean 9.49652
 StDev 4.16896
 Variance 17.3802
 Skewness 0.656983
 Kurtosis 1.25466
 N 21

Minimum 1.2070
 1st Quartile 6.5800
 Median 9.3600
 3rd Quartile 10.8250
 Maximum 19.7000

95% Confidence Interval for Mu

7.5988 11.3942

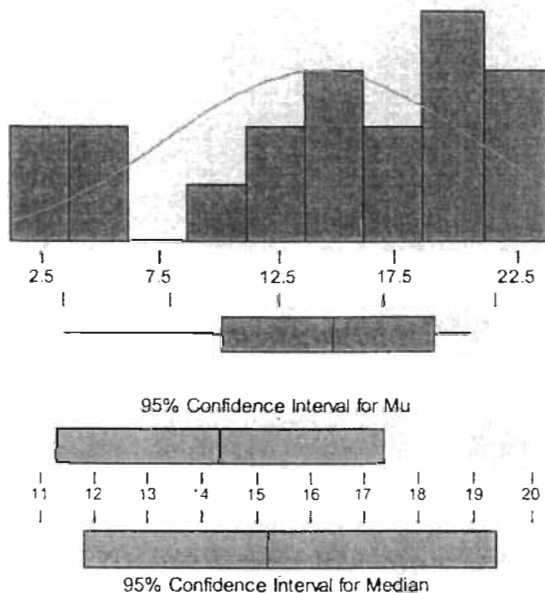
95% Confidence Interval for Sigma

3.1895 6.0203

95% Confidence Interval for Median

7.1372 10.3824

Descriptive Statistics



Variable: Back Half

Anderson-Darling Normality Test

A-Squared: 0.635
 P-Value: 0.083

Mean 14.3511
 StDev 6.3264
 Variance 40.0235
 Skewness -6.8E-01
 Kurtosis -7.4E-01
 N 19

Minimum 2.5900
 1st Quartile 10.0600
 Median 15.2200
 3rd Quartile 19.9400
 Maximum 21.4600

95% Confidence Interval for Mu

11.3018 17.4003

95% Confidence Interval for Sigma

4.7803 9.3557

95% Confidence Interval for Median

11.8572 19.3957



GE International
Power Systems

Brahim Richani, Ph.D.
Manager – GPPSD/PPE CC Systems, Applications & Environmental Engineering
(518) 385-5368
Fax: (518) 381-7450

Global Power Plant Systems Dept.
GE International, Inc.
1 River Road, Bldg. 2 - Room 304
Schenectady, NY 12345

June 17, 2003

Mr. John Gnecco
Florida Power and Light
Email: John_Gnecco@fpl.com
Tel: 561-694-4000

SUBJECT: Particulate Matter Emissions: GE PG7241FA DLN Combustion Turbines

Dear Mr. Gnecco:

In response to your request of PM-10 emissions data for GE PG7241 DLN (7FA) gas turbines, enclosed is a summary of the data gathered to date on our 7FA units with natural gas firing. All of the emissions data included in this summary are for natural gas-fired operations only.

From the enclosed summary, it is concluded that PM-10 emissions (front and back half) can range from 1 to 29 lbs/hr with an average of 7.5 lbs/hr. Front half emissions range from 0 to 17 lbs/hr with an average of 4.8 lbs/hr, and back half emissions range from 0 to 15 lbs/hr with an average of 2.8 lbs/hr.

As evident in the summary data, PM-10 emissions vary widely although they reflect emissions from equivalent units (same combustor and size) firing natural gas. The variation in the data implies that there is no consistency in the gathered PM-10 emissions. Please note that the combustion process in gas turbines, specifically DLN units, is a highly efficient, complete and repeatable process with a narrow and very specific range of allowable operating conditions. Once these units are field tuned and certified during the commissioning process, there are no operator adjustments conducted altering the combustion process thereafter. Due to the specific characteristics of the combustion process and the variation in the gathered data, GE believes that PM-10 emissions from its 7FA natural gas-fired units are essentially zero (no emissions from the combustion process itself). Therefore, it is impractical to speciate any PM-10 emissions from the combustion process.

The reported levels in the gathered data are due to non-combustion factors such as measurement artifacts, airborne PM which passes through the gas turbine inlet air filters, airborne construction debris, metallic rust or oxidation products, etc. It is anticipated that front-half (filterable) PM-10 emissions include ambient air and/or fuel quality effects for which GE has no control of and they generally may contain:

- Airborne PM-10 that passes through the gas turbine inlet air filters

- Particulate matter (inert solids) in the fuel gas supply
- Airborne construction debris (present in the inlet or exhaust equipment)
- Metallic rust or oxidation products (present in the inlet or exhaust equipment)
- Measurement (Method 5) artifacts

Additionally, back-half (condensable) PM-10 emissions are mostly from site-specific fuel contaminants and may contain:

- Formation of ammonia sulfates from the SCR system
- Sulfates even w/o an SCR system
- Unburned fuel hydrocarbons that agglomerate to form particles
- Possible other undefined condensables

I hope you find this summary helpful for your permitting needs. If you have any questions, or need additional information, please call me.

Sincerely,

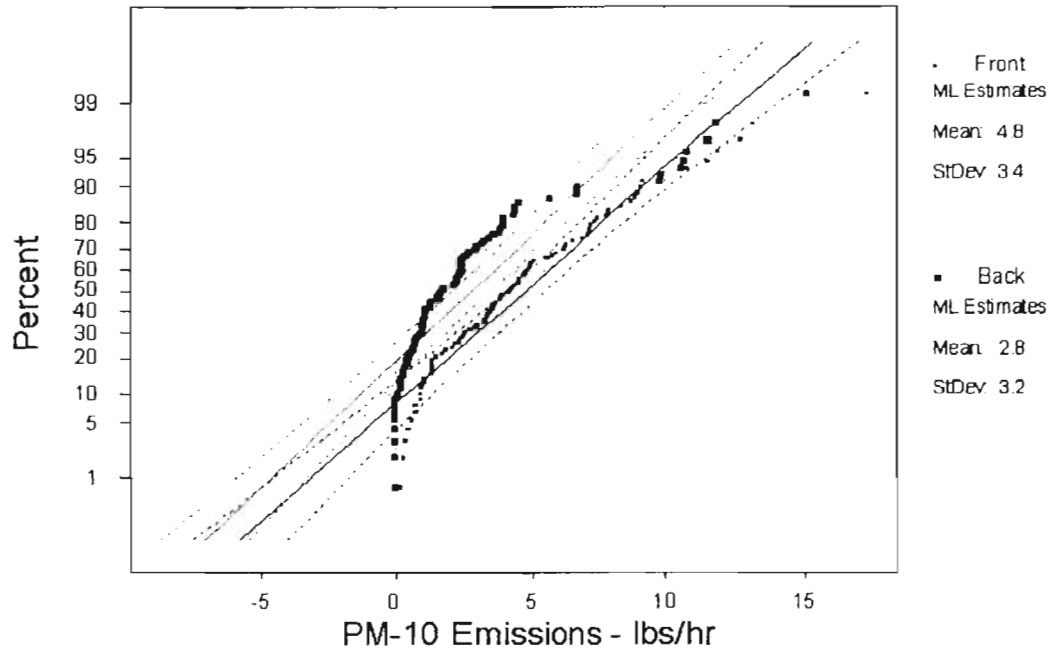


Brahim Richani, Ph.D.
Manager

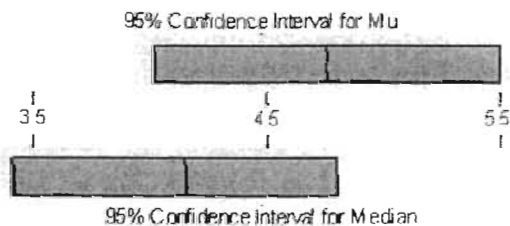
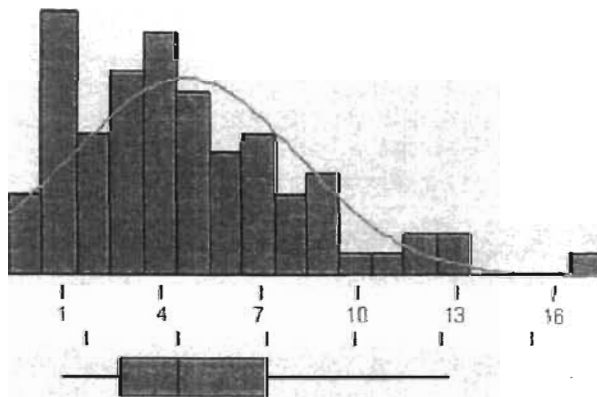
Enclosure

cc: Ken Kosky – Golder Associates – kkosky@golder.com; Tel: 352-336-5600
Frank Brooks – GE
Joel Chalfin – GE
Jeanne Beres - GE

Normal Probability Plot for Front & Back Halfs



Descriptive Statistics



Variable: Front Half

Anderson-Darling Normality Test

A-Squared: 1.400
P-Value: 0.001

Mean: 4.76165
StDev: 3.43445
Variance: 11.7954
Skewness: 1.07651
Kurtosis: 1.34730
N: 84

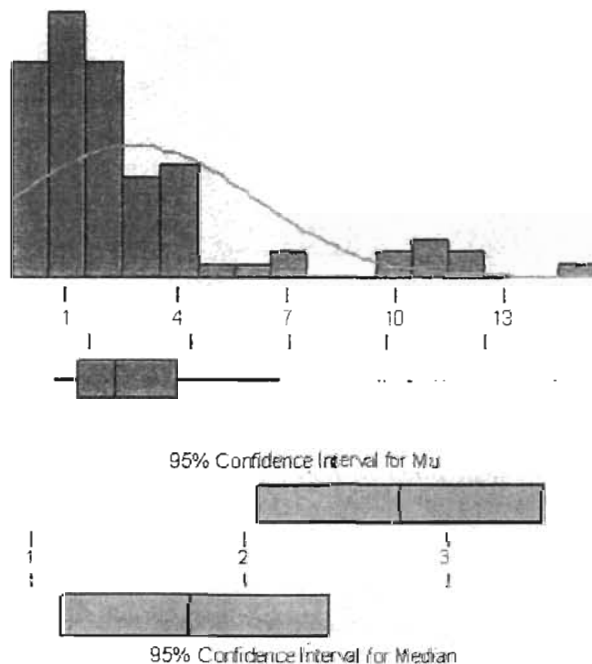
Minimum: 0.2400
1st Quartile: 2.1212
Median: 4.1500
3rd Quartile: 7.0850
Maximum: 17.3800

95% Confidence Interval for Mu:
4.0163 5.5070

95% Confidence Interval for Sigma:
2.9821 4.0498

95% Confidence Interval for Median:
3.4144 4.8127

Descriptive Statistics



Variable: Back Half

Anderson-Darling Normality Test

A-Squared: 6.800
P-Value: 0.000

Mean: 2.76214
StDev: 3.21017
Variance: 10.3052
Skewness: 1.96176
Kurtosis: 3.56237
N: 84

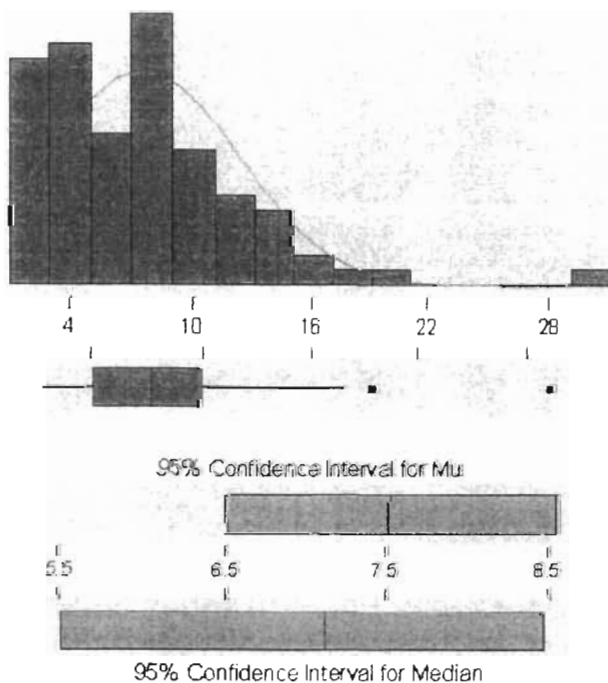
Minimum: 0.0000
1st Quartile: 0.6825
Median: 1.7350
3rd Quartile: 3.5425
Maximum: 15.1100

95% Confidence Interval for Mu
2.0655 3.4588

95% Confidence Interval for Sigma
2.7874 3.7854

95% Confidence Interval for Median
1.1300 2.4243

Descriptive Statistics



Variable: Front & Back Half

Anderson-Darling Normality Test

A-Squared: 1.368
P-Value: 0.001

Mean: 7.52395
StDev: 4.72575
Variance: 22.3327
Skewness: 1.50019
Kurtosis: 4.33434
N: 84

Minimum: 1.3600
1st Quartile: 3.9625
Median: 7.1100
3rd Quartile: 9.7750
Maximum: 29.2300

95% Confidence Interval for Mu
6.4984 8.5495

95% Confidence Interval for Sigma
4.1033 5.5725

95% Confidence Interval for Median
5.5049 8.4599

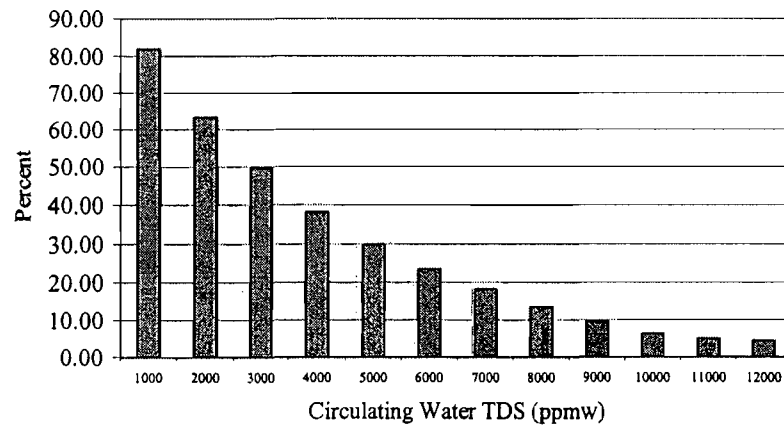
**PM AND PM₁₀ EMISSION RATE
CALCULATIONS FOR COOLING TOWER**

TDS (ppmw)	PM Emission Rate (lb/hr)	Percent of Emissions < or = PM10 %	PM10 Emissions (lb/hr)
1000	1.531	82.04	1.256
2000	3.062	63.50	1.945
3000	4.594	50.00	2.297
4000	6.125	38.33	2.348
5000	7.656	29.97	2.295
6000	9.187	23.59	2.167
7000	10.719	18.20	1.951
8000	12.250	13.57	1.662
9000	13.781	9.65	1.330
10000	15.312	6.28	0.962
11000	16.843	5.11	0.861
12000	18.375	4.46	0.820
30000	45.937	0.76	0.349
89600	137.198	0.22	0.302

Tower Circulation Rate (GPM)	Drift Rate %
306,000	0.001

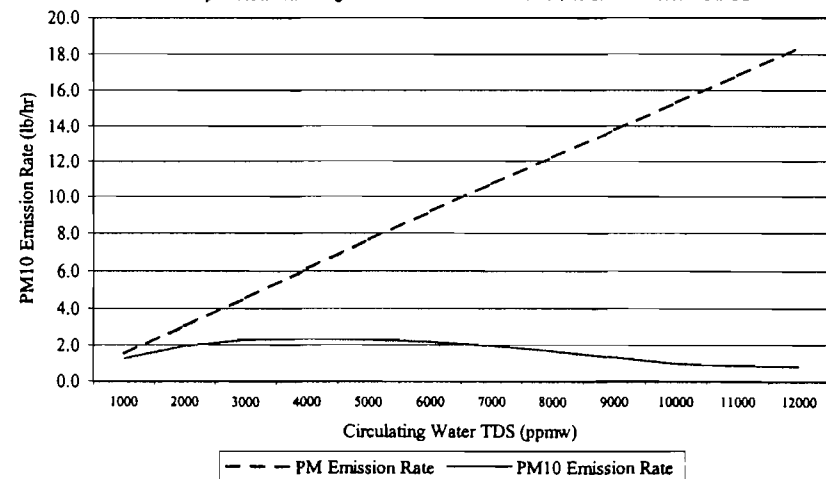
Calculated PM10 % < or = PM10 %
82.04
63.50
50.00
38.33
29.97
23.59
18.20
13.57
9.65
6.28
5.11
4.46
0.76
0.22

Percentage of Drift PM that Evaporates to PM10



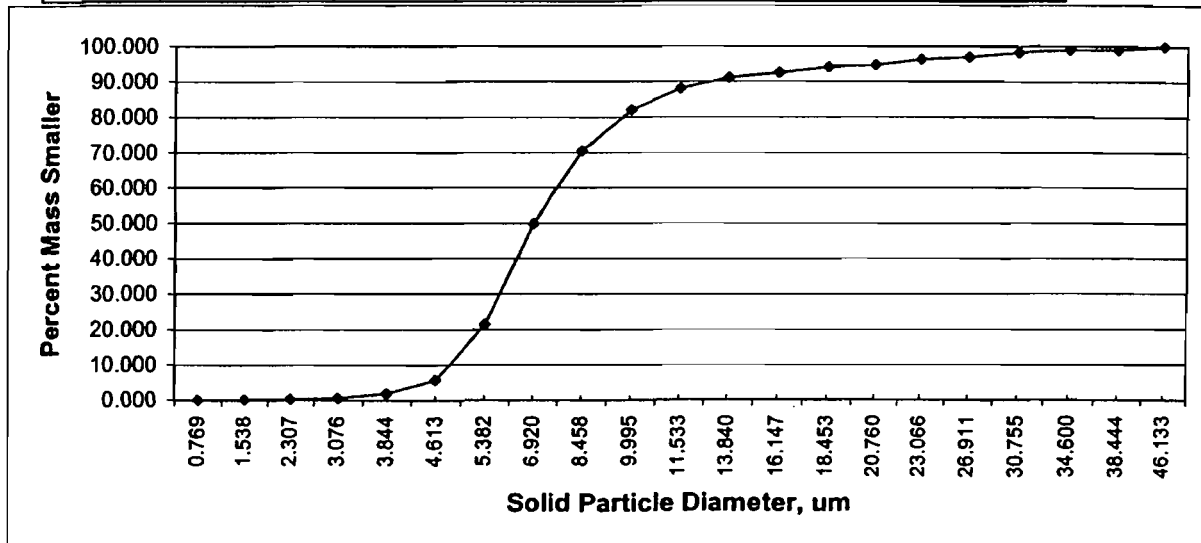
PM10 Emission Rate vs TDS

Data presented for wet cooling tower with water circulation rate of 187,400 GPM and 0.0005% drift rate.



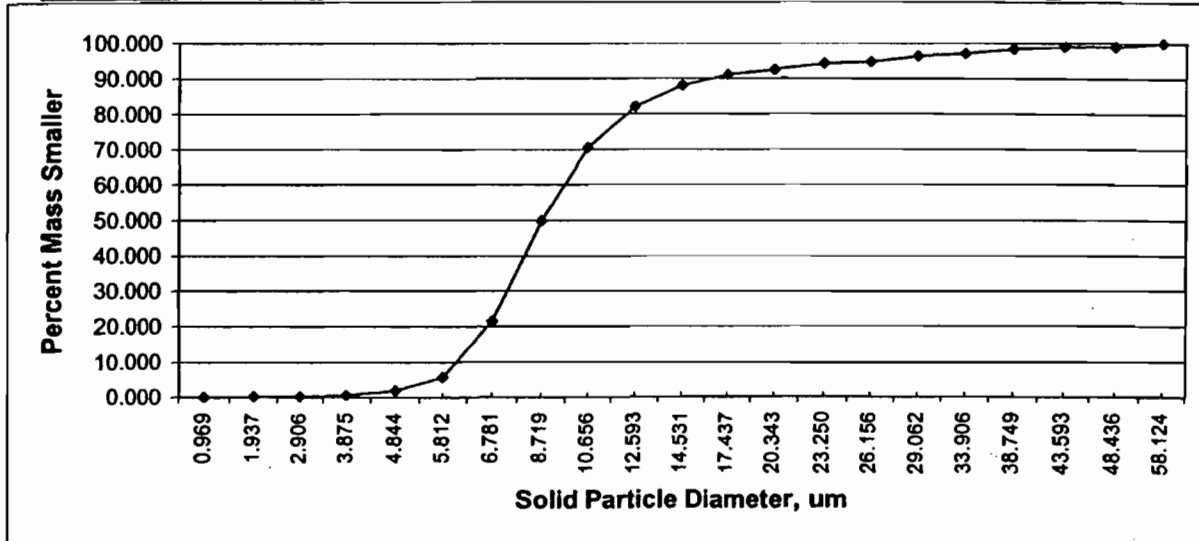
Resultant Solid Particulate Size Distribution (TDS = 1000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-07	0.24	0.769	0.000
20	4188.8	4.19E-03	4.19E-06	1.90	1.538	0.196
30	14137.2	1.41E-02	1.41E-05	6.43	2.307	0.226
40	33510.3	3.35E-02	3.35E-05	15.23	3.076	0.514
50	65449.8	6.54E-02	6.54E-05	29.75	3.844	1.816
60	113097.3	1.13E-01	1.13E-04	51.41	4.613	5.702
70	179594.4	1.80E-01	1.80E-04	81.63	5.382	21.348
90	381703.5	3.82E-01	3.82E-04	173.50	6.920	49.812
110	696910.0	6.97E-01	6.97E-04	316.78	8.458	70.509
130	1150346.5	1.15E+00	1.15E-03	522.88	9.995	82.023
150	1767145.9	1.77E+00	1.77E-03	803.25	11.533	88.012
180	3053628.1	3.05E+00	3.05E-03	1388.01	13.840	91.032
210	4849048.3	4.85E+00	4.85E-03	2204.11	16.147	92.468
240	7238229.5	7.24E+00	7.24E-03	3290.10	18.453	94.091
270	10305994.7	1.03E+01	1.03E-02	4684.54	20.760	94.689
300	14137166.9	1.41E+01	1.41E-02	6425.98	23.066	96.288
350	22449297.5	2.24E+01	2.24E-02	10204.23	26.911	97.011
400	33510321.6	3.35E+01	3.35E-02	15231.96	30.755	98.340
450	47712938.4	4.77E+01	4.77E-02	21687.70	34.600	99.071
500	65449846.9	6.54E+01	6.54E-02	29749.93	38.444	99.071
600	113097335.5	1.13E+02	1.13E-01	51407.88	46.133	100.000



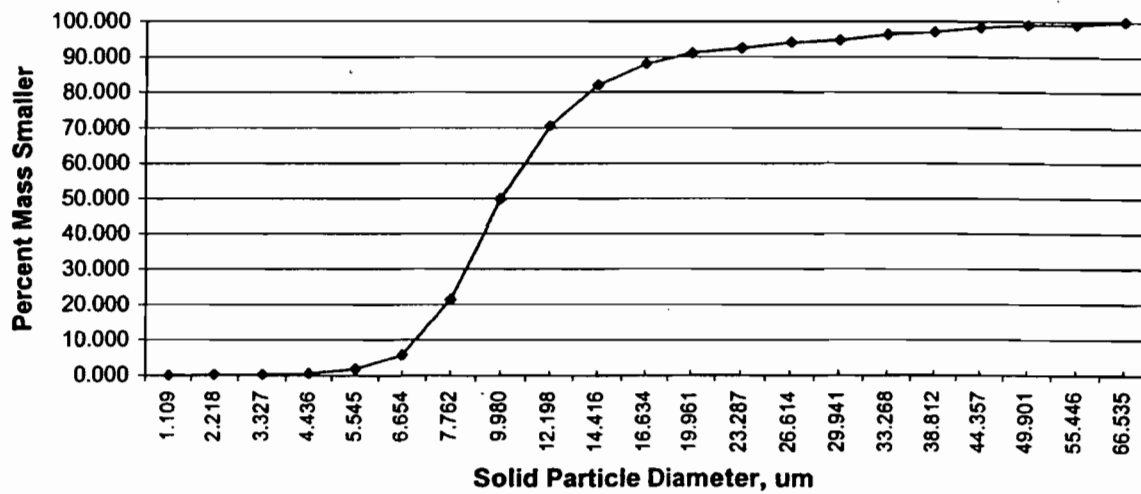
Resultant Solid Particulate Size Distribution (TDS = 2000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.05E-06	0.48	0.969	0.000
20	4188.8	4.19E-03	8.38E-06	3.81	1.937	0.196
30	14137.2	1.41E-02	2.83E-05	12.85	2.906	0.226
40	33510.3	3.35E-02	6.70E-05	30.46	3.875	0.514
50	65449.8	6.54E-02	1.31E-04	59.50	4.844	1.816
60	113097.3	1.13E-01	2.26E-04	102.82	5.812	5.702
70	179594.4	1.80E-01	3.59E-04	163.27	6.781	21.348
90	381703.5	3.82E-01	7.63E-04	347.00	8.719	49.812
110	696910.0	6.97E-01	1.39E-03	633.55	10.656	70.509
130	1150346.5	1.15E+00	2.30E-03	1045.77	12.593	82.023
150	1767145.9	1.77E+00	3.53E-03	1606.50	14.531	88.012
180	3053628.1	3.05E+00	6.11E-03	2776.03	17.437	91.032
210	4849048.3	4.85E+00	9.70E-03	4408.23	20.343	92.468
240	7238229.5	7.24E+00	1.45E-02	6580.21	23.250	94.091
270	10305994.7	1.03E+01	2.06E-02	9369.09	26.156	94.689
300	14137166.9	1.41E+01	2.83E-02	12851.97	29.062	96.288
350	22449297.5	2.24E+01	4.49E-02	20408.45	33.906	97.011
400	33510321.6	3.35E+01	6.70E-02	30463.93	38.749	98.340
450	47712938.4	4.77E+01	9.54E-02	43375.40	43.593	99.071
500	65449846.9	6.54E+01	1.31E-01	59499.86	48.436	99.071
600	113097335.5	1.13E+02	2.26E-01	102815.76	58.124	100.000



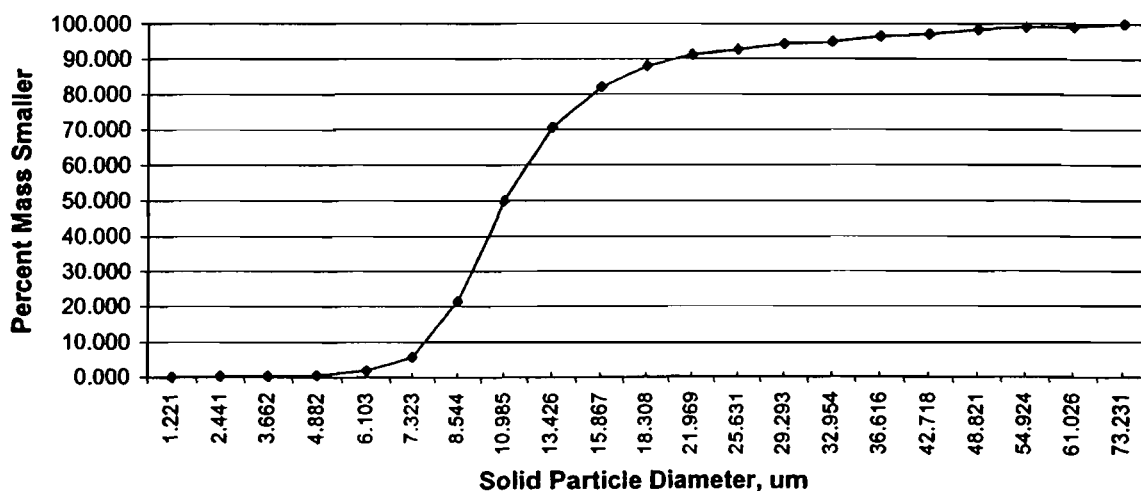
Resultant Solid Particulate Size Distribution (TDS = 3000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.57E-06	0.71	1.109	0.000
20	4188.8	4.19E-03	1.26E-05	5.71	2.218	0.196
30	14137.2	1.41E-02	4.24E-05	19.28	3.327	0.226
40	33510.3	3.35E-02	1.01E-04	45.70	4.436	0.514
50	65449.8	6.54E-02	1.96E-04	89.25	5.545	1.816
60	113097.3	1.13E-01	3.39E-04	154.22	6.654	5.702
70	179594.4	1.80E-01	5.39E-04	244.90	7.762	21.348
90	381703.5	3.82E-01	1.15E-03	520.50	9.980	49.812
110	696910.0	6.97E-01	2.09E-03	950.33	12.198	70.509
130	1150346.5	1.15E+00	3.45E-03	1568.65	14.416	82.023
150	1767145.9	1.77E+00	5.30E-03	2409.74	16.634	88.012
180	3053628.1	3.05E+00	9.16E-03	4164.04	19.961	91.032
210	4849048.3	4.85E+00	1.45E-02	6612.34	23.287	92.468
240	7238229.5	7.24E+00	2.17E-02	9870.31	26.614	94.091
270	10305994.7	1.03E+01	3.09E-02	14053.63	29.941	94.689
300	14137166.9	1.41E+01	4.24E-02	19277.95	33.268	96.288
350	22449297.5	2.24E+01	6.73E-02	30612.68	38.812	97.011
400	33510321.6	3.35E+01	1.01E-01	45695.89	44.357	98.340
450	47712938.4	4.77E+01	1.43E-01	65063.10	49.901	99.071
500	65449846.9	6.54E+01	1.96E-01	89249.79	55.446	99.071
600	113097335.5	1.13E+02	3.39E-01	154223.64	66.535	100.000



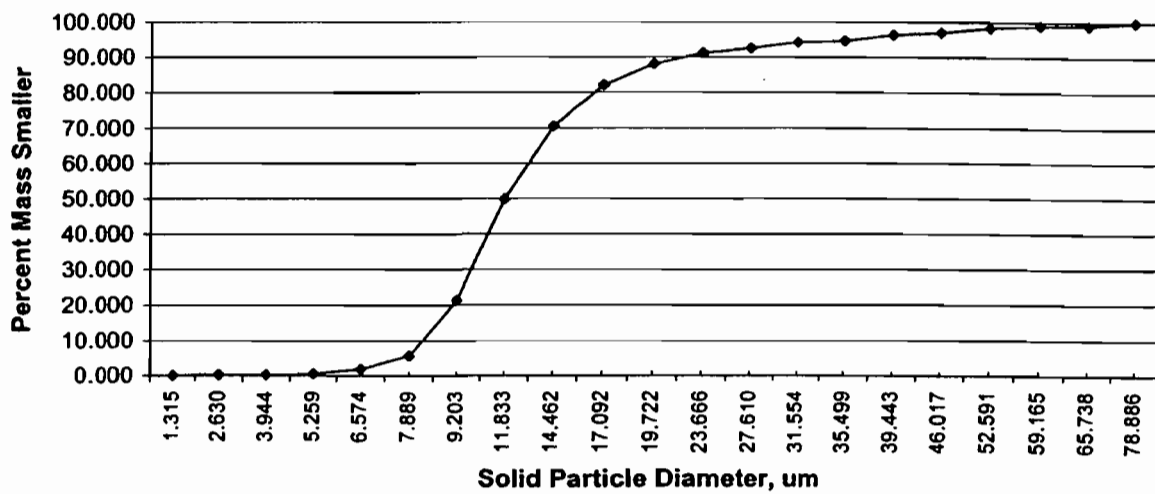
Resultant Solid Particulate Size Distribution (TDS = 4000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	2.09E-06	0.95	1.221	0.000
20	4188.8	4.19E-03	1.68E-05	7.62	2.441	0.196
30	14137.2	1.41E-02	5.65E-05	25.70	3.662	0.226
40	33510.3	3.35E-02	1.34E-04	60.93	4.882	0.514
50	65449.8	6.54E-02	2.62E-04	119.00	6.103	1.816
60	113097.3	1.13E-01	4.52E-04	205.63	7.323	5.702
70	179594.4	1.80E-01	7.18E-04	326.54	8.544	21.348
90	381703.5	3.82E-01	1.53E-03	694.01	10.985	49.812
110	696910.0	6.97E-01	2.79E-03	1267.11	13.426	70.509
130	1150346.5	1.15E+00	4.60E-03	2091.54	15.867	82.023
150	1767145.9	1.77E+00	7.07E-03	3212.99	18.308	88.012
180	3053628.1	3.05E+00	1.22E-02	5552.05	21.969	91.032
210	4849048.3	4.85E+00	1.94E-02	8816.45	25.631	92.468
240	7238229.5	7.24E+00	2.90E-02	13160.42	29.293	94.091
270	10305994.7	1.03E+01	4.12E-02	18738.17	32.954	94.689
300	14137166.9	1.41E+01	5.65E-02	25703.94	36.616	96.288
350	22449297.5	2.24E+01	8.98E-02	40816.90	42.718	97.011
400	33510321.6	3.35E+01	1.34E-01	60927.86	48.821	98.340
450	47712938.4	4.77E+01	1.91E-01	86750.80	54.924	99.071
500	65449846.9	6.54E+01	2.62E-01	118999.72	61.026	99.071
600	113097335.5	1.13E+02	4.52E-01	205631.52	73.231	100.000



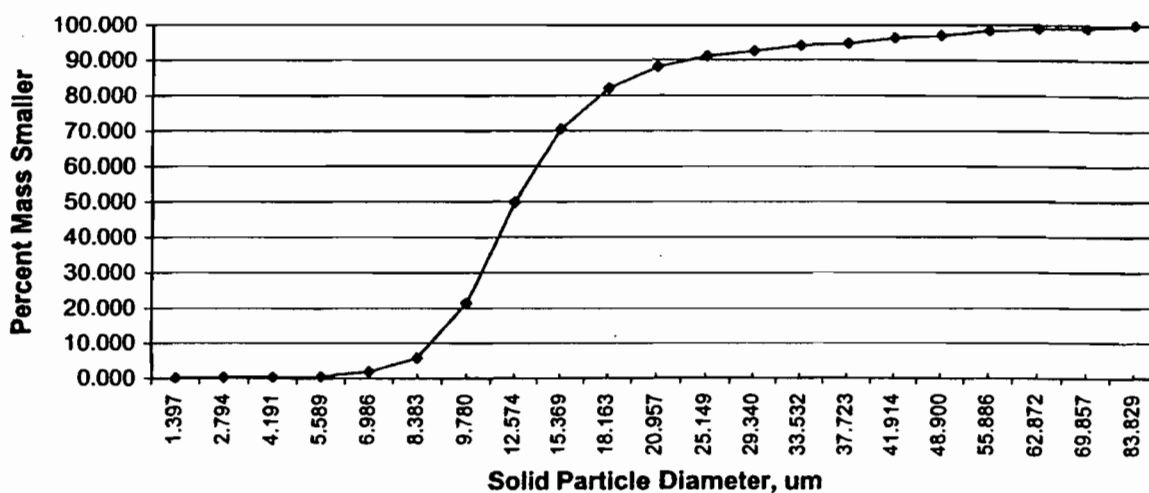
Resultant Solid Particulate Size Distribution (TDS = 5000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	2.62E-06	1.19	1.315	0.000
20	4188.8	4.19E-03	2.09E-05	9.52	2.630	0.196
30	14137.2	1.41E-02	7.07E-05	32.13	3.944	0.226
40	33510.3	3.35E-02	1.68E-04	76.16	5.259	0.514
50	65449.8	6.54E-02	3.27E-04	148.75	6.574	1.816
60	113097.3	1.13E-01	5.65E-04	257.04	7.889	5.702
70	179594.4	1.80E-01	8.98E-04	408.17	9.203	21.348
90	381703.5	3.82E-01	1.91E-03	867.51	11.833	49.812
110	696910.0	6.97E-01	3.48E-03	1583.89	14.462	70.509
130	1150346.5	1.15E+00	5.75E-03	2614.42	17.092	82.023
150	1767145.9	1.77E+00	8.84E-03	4016.24	19.722	88.012
180	3053628.1	3.05E+00	1.53E-02	6940.06	23.666	91.032
210	4849048.3	4.85E+00	2.42E-02	11020.56	27.610	92.468
240	7238229.5	7.24E+00	3.62E-02	16450.52	31.554	94.091
270	10305994.7	1.03E+01	5.15E-02	23422.72	35.499	94.689
300	14137166.9	1.41E+01	7.07E-02	32129.92	39.443	96.288
350	22449297.5	2.24E+01	1.12E-01	51021.13	46.017	97.011
400	33510321.6	3.35E+01	1.68E-01	76159.82	52.591	98.340
450	47712938.4	4.77E+01	2.39E-01	108438.50	59.165	99.071
500	65449846.9	6.54E+01	3.27E-01	148749.65	65.738	99.071
600	113097335.5	1.13E+02	5.65E-01	257039.40	78.886	100.000



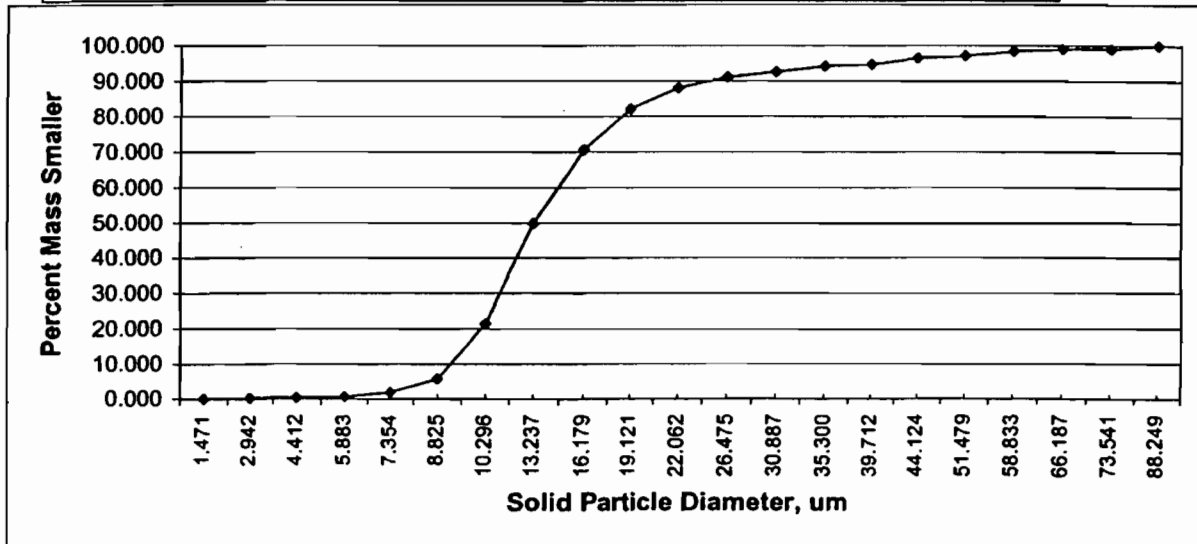
Resultant Solid Particulate Size Distribution (TDS = 6000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.14E-06	1.43	1.397	0.000
20	4188.8	4.19E-03	2.51E-05	11.42	2.794	0.196
30	14137.2	1.41E-02	8.48E-05	38.56	4.191	0.226
40	33510.3	3.35E-02	2.01E-04	91.39	5.589	0.514
50	65449.8	6.54E-02	3.93E-04	178.50	6.986	1.816
60	113097.3	1.13E-01	6.79E-04	308.45	8.383	5.702
70	179594.4	1.80E-01	1.08E-03	489.80	9.780	21.348
90	381703.5	3.82E-01	2.29E-03	1041.01	12.574	49.812
110	696910.0	6.97E-01	4.18E-03	1900.66	15.369	70.509
130	1150346.5	1.15E+00	6.90E-03	3137.31	18.163	82.023
150	1767145.9	1.77E+00	1.06E-02	4819.49	20.957	88.012
180	3053628.1	3.05E+00	1.83E-02	8328.08	25.149	91.032
210	4849048.3	4.85E+00	2.91E-02	13224.68	29.340	92.468
240	7238229.5	7.24E+00	4.34E-02	19740.63	33.532	94.091
270	10305994.7	1.03E+01	6.18E-02	28107.26	37.723	94.689
300	14137166.9	1.41E+01	8.48E-02	38555.91	41.914	96.288
350	22449297.5	2.24E+01	1.35E-01	61225.36	48.900	97.011
400	33510321.6	3.35E+01	2.01E-01	91391.79	55.886	98.340
450	47712938.4	4.77E+01	2.86E-01	130126.20	62.872	99.071
500	65449846.9	6.54E+01	3.93E-01	178499.58	69.857	99.071
600	113097335.5	1.13E+02	6.79E-01	308447.28	83.829	100.000



Resultant Solid Particulate Size Distribution (TDS = 7000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.67E-06	1.67	1.471	0.000
20	4188.8	4.19E-03	2.93E-05	13.33	2.942	0.196
30	14137.2	1.41E-02	9.90E-05	44.98	4.412	0.226
40	33510.3	3.35E-02	2.35E-04	106.62	5.883	0.514
50	65449.8	6.54E-02	4.58E-04	208.25	7.354	1.816
60	113097.3	1.13E-01	7.92E-04	359.86	8.825	5.702
70	179594.4	1.80E-01	1.26E-03	571.44	10.296	21.348
90	381703.5	3.82E-01	2.67E-03	1214.51	13.237	49.812
110	696910.0	6.97E-01	4.88E-03	2217.44	16.179	70.509
130	1150346.5	1.15E+00	8.05E-03	3660.19	19.121	82.023
150	1767145.9	1.77E+00	1.24E-02	5622.74	22.062	88.012
180	3053628.1	3.05E+00	2.14E-02	9716.09	26.475	91.032
210	4849048.3	4.85E+00	3.39E-02	15428.79	30.887	92.468
240	7238229.5	7.24E+00	5.07E-02	23030.73	35.300	94.091
270	10305994.7	1.03E+01	7.21E-02	32791.80	39.712	94.689
300	14137166.9	1.41E+01	9.90E-02	44981.89	44.124	96.288
350	22449297.5	2.24E+01	1.57E-01	71429.58	51.479	97.011
400	33510321.6	3.35E+01	2.35E-01	106623.75	58.833	98.340
450	47712938.4	4.77E+01	3.34E-01	151813.89	66.187	99.071
500	65449846.9	6.54E+01	4.58E-01	208249.51	73.541	99.071
600	113097335.5	1.13E+02	7.92E-01	359855.16	88.249	100.000

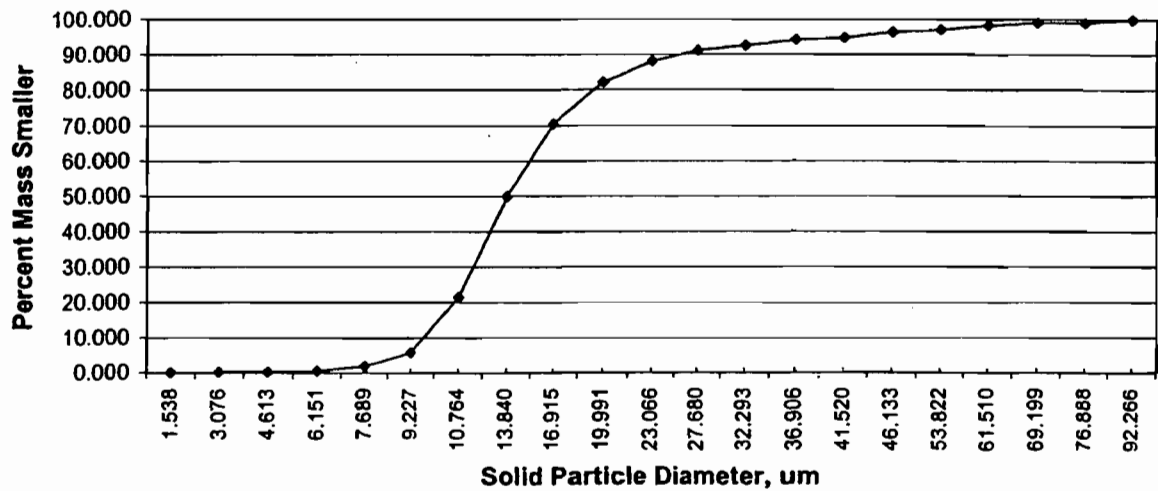


Resultant Solid Particulate Size Distribution (TDS = 9000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4188.8	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137.2	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510.3	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65449.8	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097.3	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594.4	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381703.5	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910.0	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150346.5	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767145.9	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628.1	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048.3	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229.5	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305994.7	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137166.9	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449297.5	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510321.6	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938.4	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449846.9	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097335.5	1.13E+02	8.71E-01	395840.67	91.098	100.000

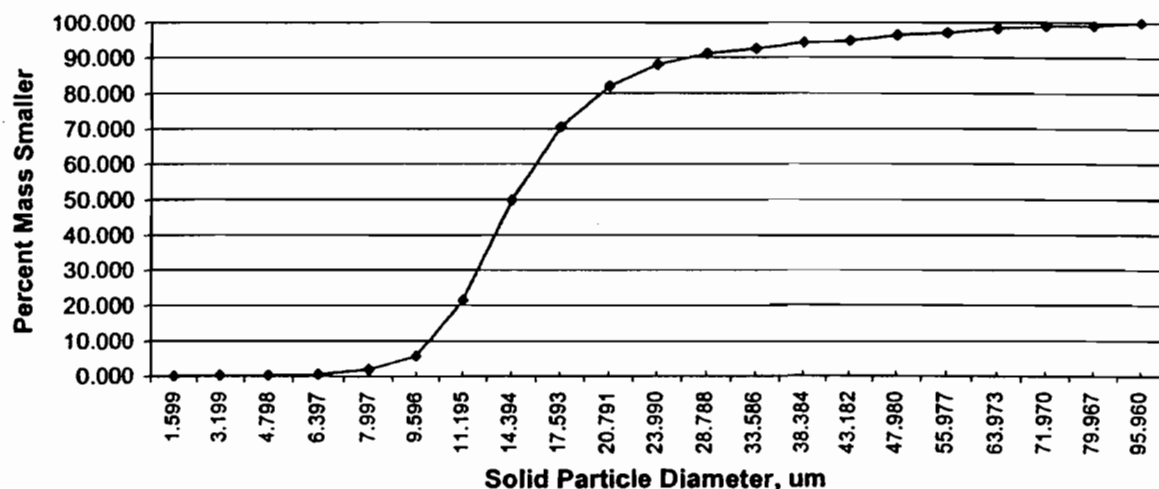
Resultant Solid Particulate Size Distribution (TDS = 8000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.19E-06	1.90	1.538	0.000
20	4188.8	4.19E-03	3.35E-05	15.23	3.076	0.196
30	14137.2	1.41E-02	1.13E-04	51.41	4.613	0.226
40	33510.3	3.35E-02	2.68E-04	121.86	6.151	0.514
50	65449.8	6.54E-02	5.24E-04	238.00	7.689	1.816
60	113097.3	1.13E-01	9.05E-04	411.26	9.227	5.702
70	179594.4	1.80E-01	1.44E-03	653.07	10.764	21.348
90	381703.5	3.82E-01	3.05E-03	1388.01	13.840	49.812
110	696910.0	6.97E-01	5.58E-03	2534.22	16.915	70.509
130	1150346.5	1.15E+00	9.20E-03	4183.08	19.991	82.023
150	1767145.9	1.77E+00	1.41E-02	6425.98	23.066	88.012
180	3053628.1	3.05E+00	2.44E-02	11104.10	27.680	91.032
210	4849048.3	4.85E+00	3.88E-02	17632.90	32.293	92.468
240	7238229.5	7.24E+00	5.79E-02	26320.83	36.906	94.091
270	10305994.7	1.03E+01	8.24E-02	37476.34	41.520	94.689
300	14137166.9	1.41E+01	1.13E-01	51407.88	46.133	96.288
350	22449297.5	2.24E+01	1.80E-01	81633.81	53.822	97.011
400	33510321.6	3.35E+01	2.68E-01	121855.72	61.510	98.340
450	47712938.4	4.77E+01	3.82E-01	173501.59	69.199	99.071
500	65449846.9	6.54E+01	5.24E-01	237999.44	76.888	99.071
600	113097335.5	1.13E+02	9.05E-01	411263.04	92.266	100.000



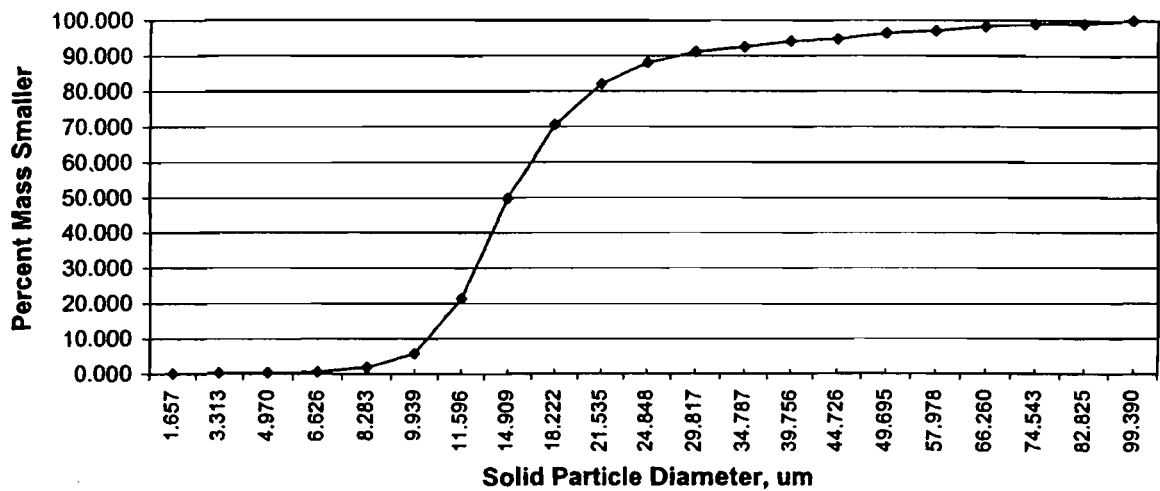
Resultant Solid Particulate Size Distribution (TDS = 9000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.71E-06	2.14	1.599	0.000
20	4188.8	4.19E-03	3.77E-05	17.14	3.199	0.196
30	14137.2	1.41E-02	1.27E-04	57.83	4.798	0.226
40	33510.3	3.35E-02	3.02E-04	137.09	6.397	0.514
50	65449.8	6.54E-02	5.89E-04	267.75	7.997	1.816
60	113097.3	1.13E-01	1.02E-03	462.67	9.596	5.702
70	179594.4	1.80E-01	1.62E-03	734.70	11.195	21.348
90	381703.5	3.82E-01	3.44E-03	1561.51	14.394	49.812
110	696910.0	6.97E-01	6.27E-03	2851.00	17.593	70.509
130	1150346.5	1.15E+00	1.04E-02	4705.96	20.791	82.023
150	1767145.9	1.77E+00	1.59E-02	7229.23	23.990	88.012
180	3053628.1	3.05E+00	2.75E-02	12492.11	28.788	91.032
210	4849048.3	4.85E+00	4.36E-02	19837.02	33.586	92.468
240	7238229.5	7.24E+00	6.51E-02	29610.94	38.384	94.091
270	10305994.7	1.03E+01	9.28E-02	42160.89	43.182	94.689
300	14137166.9	1.41E+01	1.27E-01	57833.86	47.980	96.288
350	22449297.5	2.24E+01	2.02E-01	91838.04	55.977	97.011
400	33510321.6	3.35E+01	3.02E-01	137087.68	63.973	98.340
450	47712938.4	4.77E+01	4.29E-01	195189.29	71.970	99.071
500	65449846.9	6.54E+01	5.89E-01	267749.37	79.967	99.071
600	113097335.5	1.13E+02	1.02E+00	462670.92	95.960	100.000



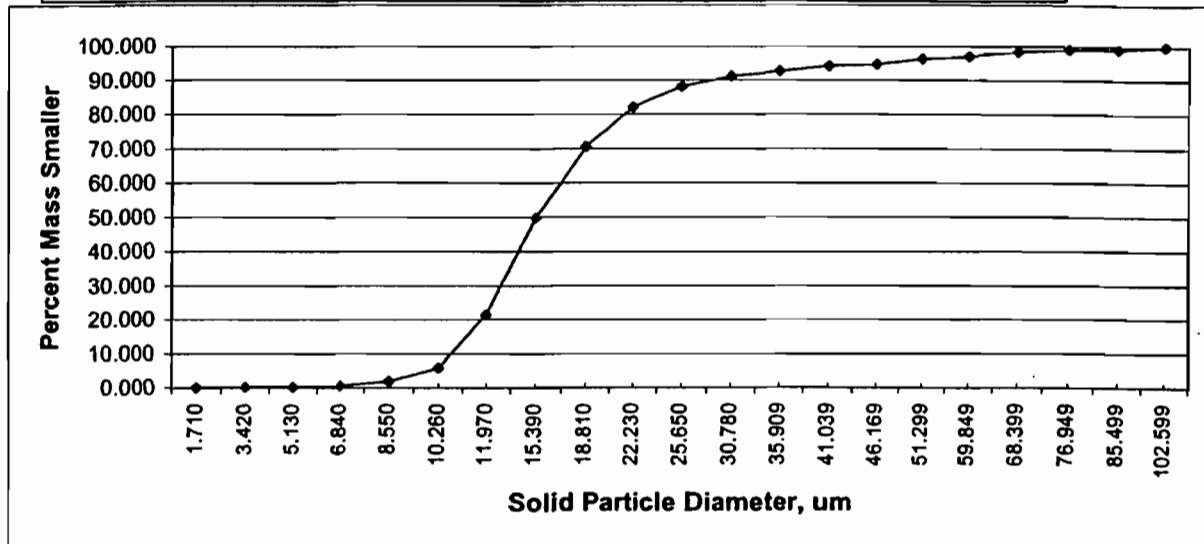
Resultant Solid Particulate Size Distribution (TDS = 10000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-06	2.38	1.657	0.000
20	4188.8	4.19E-03	4.19E-05	19.04	3.313	0.196
30	14137.2	1.41E-02	1.41E-04	64.26	4.970	0.226
40	33510.3	3.35E-02	3.35E-04	152.32	6.626	0.514
50	65449.8	6.54E-02	6.54E-04	297.50	8.283	1.816
60	113097.3	1.13E-01	1.13E-03	514.08	9.939	5.702
70	179594.4	1.80E-01	1.80E-03	816.34	11.596	21.348
90	381703.5	3.82E-01	3.82E-03	1735.02	14.909	49.812
110	696910.0	6.97E-01	6.97E-03	3167.77	18.222	70.509
130	1150346.5	1.15E+00	1.15E-02	5228.85	21.535	82.023
150	1767145.9	1.77E+00	1.77E-02	8032.48	24.848	88.012
180	3053628.1	3.05E+00	3.05E-02	13880.13	29.817	91.032
210	4849048.3	4.85E+00	4.85E-02	22041.13	34.787	92.468
240	7238229.5	7.24E+00	7.24E-02	32901.04	39.756	94.091
270	10305994.7	1.03E+01	1.03E-01	46845.43	44.726	94.689
300	14137166.9	1.41E+01	1.41E-01	64259.85	49.695	96.288
350	22449297.5	2.24E+01	2.24E-01	102042.26	57.978	97.011
400	33510321.6	3.35E+01	3.35E-01	152319.64	66.260	98.340
450	47712938.4	4.77E+01	4.77E-01	216878.99	74.543	99.071
500	65449846.9	6.54E+01	6.54E-01	297499.30	82.825	99.071
600	113097335.5	1.13E+02	1.13E+00	514078.80	99.390	100.000



Resultant Solid Particulate Size Distribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4188.8	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137.2	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510.3	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65449.8	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097.3	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594.4	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381703.5	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910.0	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150346.5	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767145.9	1.77E+00	1.94E-02	8835.73	25.850	88.012
180	3053628.1	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048.3	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229.5	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305994.7	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137166.9	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449297.5	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510321.6	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938.4	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449846.9	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097335.5	1.13E+02	1.24E+00	565486.68	102.599	100.000



Resultant Solid Particulate Size Distribution (TDS = 12000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	6.28E-06	2.86	1.760	0.000
20	4188.8	4.19E-03	5.03E-05	22.85	3.521	0.196
30	14137.2	1.41E-02	1.70E-04	77.11	5.281	0.226
40	33510.3	3.35E-02	4.02E-04	182.78	7.041	0.514
50	65449.8	6.54E-02	7.85E-04	357.00	8.801	1.816
60	113097.3	1.13E-01	1.36E-03	616.89	10.562	5.702
70	179594.4	1.80E-01	2.16E-03	979.61	12.322	21.348
90	381703.5	3.82E-01	4.58E-03	2082.02	15.843	49.812
110	696910.0	6.97E-01	8.36E-03	3801.33	19.363	70.509
130	1150346.5	1.15E+00	1.38E-02	6274.62	22.884	82.023
150	1767145.9	1.77E+00	2.12E-02	9638.98	26.404	88.012
180	3053628.1	3.05E+00	3.66E-02	16656.15	31.685	91.032
210	4849048.3	4.85E+00	5.82E-02	26449.35	36.966	92.468
240	7238229.5	7.24E+00	8.69E-02	39481.25	42.247	94.091
270	10305994.7	1.03E+01	1.24E-01	56214.52	47.528	94.689
300	14137166.9	1.41E+01	1.70E-01	77111.82	52.809	96.288
350	22449297.5	2.24E+01	2.69E-01	122450.71	61.610	97.011
400	33510321.6	3.35E+01	4.02E-01	182783.57	70.412	98.340
450	47712938.4	4.77E+01	5.73E-01	260252.39	79.213	99.071
500	65449846.9	6.54E+01	7.85E-01	356999.17	88.015	99.071
600	113097335.5	1.13E+02	1.36E+00	616894.56	105.618	100.000

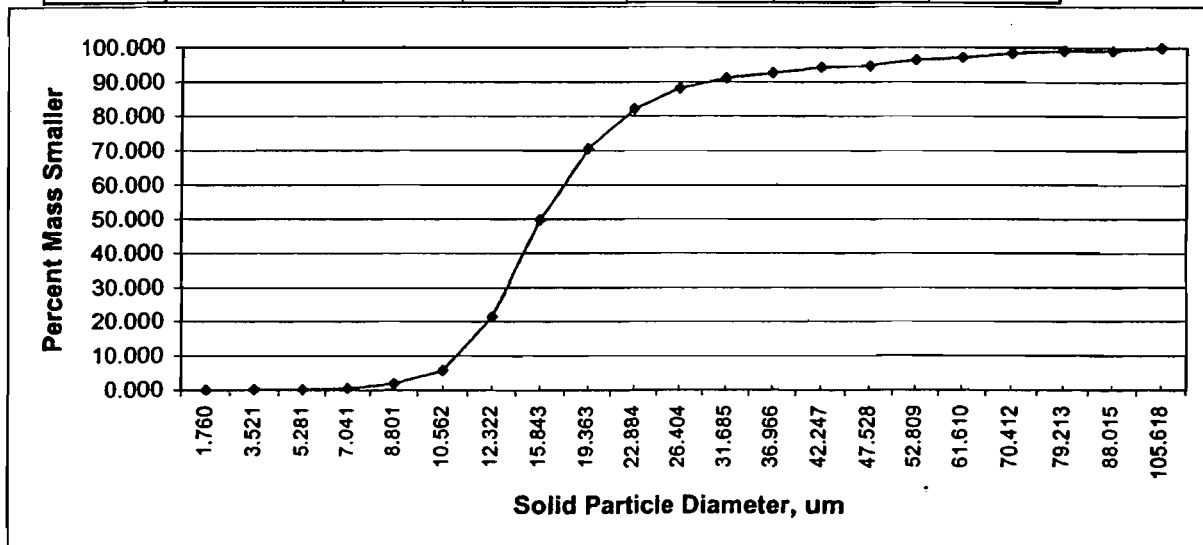


Table #. Resultant Solid Particulate Size Distribution (TDS = 30000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.57E-05	7.14	2.389	0.000
20	4188.8	4.19E-03	1.26E-04	57.12	4.778	0.196
30	14137.2	1.41E-02	4.24E-04	192.78	7.167	0.226
40	33510.3	3.35E-02	1.01E-03	456.96	9.556	0.514
50	65449.8	6.54E-02	1.96E-03	892.50	11.945	1.816
60	113097.3	1.13E-01	3.39E-03	1542.24	14.335	5.702
70	179594.4	1.80E-01	5.39E-03	2449.01	16.724	21.348
90	381703.5	3.82E-01	1.15E-02	5205.05	21.502	49.812
110	696910.0	6.97E-01	2.09E-02	9503.32	26.280	70.509
130	1150346.5	1.15E+00	3.45E-02	15686.54	31.058	82.023
150	1767145.9	1.77E+00	5.30E-02	24097.44	35.836	88.012
180	3053628.1	3.05E+00	9.16E-02	41640.38	43.004	91.032
210	4849048.3	4.85E+00	1.45E-01	66123.39	50.171	92.468
240	7238229.5	7.24E+00	2.17E-01	98703.13	57.338	94.091
270	10305994.7	1.03E+01	3.09E-01	140536.29	64.505	94.689
300	14137166.9	1.41E+01	4.24E-01	192779.55	71.673	96.288
350	22449297.5	2.24E+01	6.73E-01	306126.78	83.618	97.011
400	33510321.6	3.35E+01	1.01E+00	456958.93	95.564	98.340
450	47712938.4	4.77E+01	1.43E+00	650630.98	107.509	99.071
500	65449846.9	6.54E+01	1.96E+00	892497.91	119.455	99.071
600	113097335.5	1.13E+02	3.39E+00	1542236.39	143.346	100.000

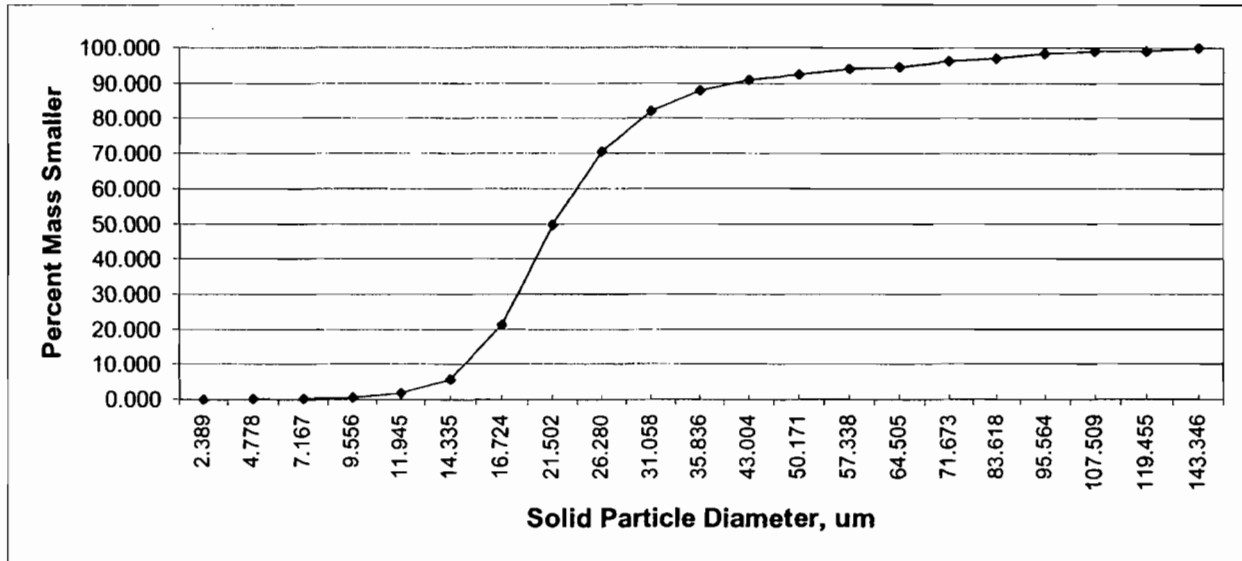
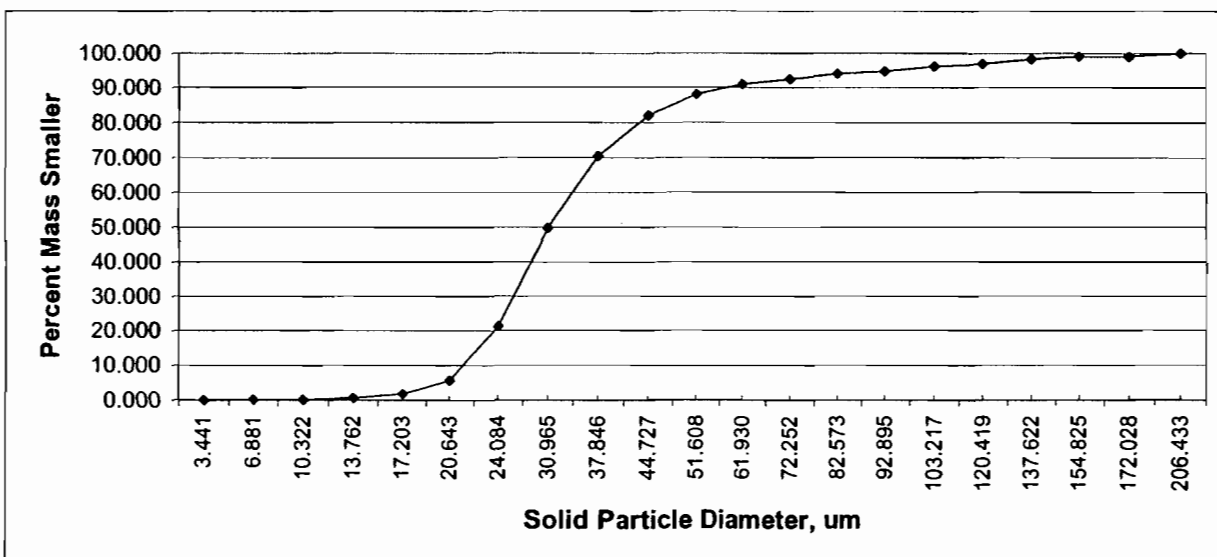


Table #. Resultant Solid Particulate Size Distribution (T DS = 89600 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um ³)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um ³)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.69E-05	21.32	3.441	0.000
20	4188.8	4.19E-03	3.75E-04	170.60	6.881	0.196
30	14137.2	1.41E-02	1.27E-03	575.77	10.322	0.226
40	33510.3	3.35E-02	3.00E-03	1364.78	13.762	0.514
50	65449.8	6.54E-02	5.86E-03	2665.59	17.203	1.816
60	113097.3	1.13E-01	1.01E-02	4606.15	20.643	5.702
70	179594.4	1.80E-01	1.61E-02	7314.39	24.084	21.348
90	381703.5	3.82E-01	3.42E-02	15545.74	30.965	49.812
110	696910.0	6.97E-01	6.24E-02	28383.24	37.846	70.509
130	1150346.5	1.15E+00	1.03E-01	46850.48	44.727	82.023
150	1767145.9	1.77E+00	1.58E-01	71971.03	51.608	88.012
180	3053628.1	3.05E+00	2.74E-01	124365.94	61.930	91.032
210	4849048.3	4.85E+00	4.34E-01	197488.51	72.252	92.468
240	7238229.5	7.24E+00	6.49E-01	294793.35	82.573	94.091
270	10305994.7	1.03E+01	9.23E-01	419735.06	92.895	94.689
300	14137166.9	1.41E+01	1.27E+00	575768.25	103.217	96.288
350	22449297.5	2.24E+01	2.01E+00	914298.66	120.419	97.011
400	33510321.6	3.35E+01	3.00E+00	1364784.01	137.622	98.340
450	47712938.4	4.77E+01	4.28E+00	1943217.86	154.825	99.071
500	65449846.9	6.54E+01	5.86E+00	2665593.77	172.028	99.071
600	113097335.5	1.13E+02	1.01E+01	4606146.03	206.433	100.000



Calculating Realistic PM₁₀ Emissions from Cooling Towers

Abstract No. 216 Session No. AM-1b

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ABSTRACT

Particulate matter less than 10 micrometers in diameter (PM₁₀) emissions from wet cooling towers may be calculated using the methodology presented in EPA's AP-42¹, which assumes that all total dissolved solids (TDS) emitted in "drift" particles (liquid water entrained in the air stream and carried out of the tower through the induced draft fan stack.) are PM₁₀. However, for wet cooling towers with medium to high TDS levels, this method is overly conservative, and predicts significantly higher PM₁₀ emissions than would actually occur, even for towers equipped with very high efficiency drift eliminators (e.g., 0.0006% drift rate). Such over-prediction may result in unrealistically high PM₁₀ modeled concentrations and/or the need to purchase expensive Emission Reduction Credits (ERCs) in PM₁₀ non-attainment areas. Since these towers have fairly low emission points (10 to 15 m above ground), over-predicting PM₁₀ emission rates can easily result in exceeding federal Prevention of Significant Deterioration (PSD) significance levels at a project's fenceline. This paper presents a method for computing realistic PM₁₀ emissions from cooling towers with medium to high TDS levels.

INTRODUCTION

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. Wet, or evaporative, cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or may provide cooling via heat exchangers, for example, steam condensers. Wet cooling towers provide direct contact between the cooling water and air passing through the tower, and as part of normal operation, a very small amount of the circulating water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Because the drift droplets contain the same chemical impurities as the water circulating through the tower, the particulate matter constituent of the drift droplets may be classified as an emission. The magnitude of the drift loss is influenced by the number and size of droplets produced within the tower, which are determined by the tower fill design, tower design, the air and water patterns, and design of the drift eliminators.

AP-42 METHOD OF CALCULATING DRIFT PARTICULATE

EPA's AP-42¹ provides available particulate emission factors for wet cooling towers, however, these values only have an emission factor rating of "E" (the lowest level of confidence acceptable). They are also rather high, compared to typical present-day manufacturers' guaranteed drift rates, which are on the order of 0.0006%. (Drift emissions are typically

expressed as a percentage of the cooling tower water circulation rate). AP-42 states that "a *conservatively high* PM₁₀ emission factor can be obtained by (a) multiplying the total liquid drift factor by the TDS fraction in the circulating water, and (b) assuming that once the water evaporates, all remaining solid particles are within the PM₁₀ range." (Italics per EPA).

If TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS for the make-up water and multiplying it by the cooling tower cycles of concentration. [The cycles of concentration is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up water.]

Using AP-42 guidance, the total particulate emissions (PM) (after the pure water has evaporated) can be expressed as:

$$PM = \text{Water Circulation Rate} \times \text{Drift Rate} \times \text{TDS} \quad [1]$$

For example, for a typical power plant wet cooling tower with a water circulation rate of 146,000 gallons per minute (gpm), drift rate of 0.0006%, and TDS of 7,700 parts per million by weight (ppmw):

$$PM = 146,000 \text{ gpm} \times 8.34 \text{ lb water/gal} \times 0.0006/100 \times 7,700 \text{ lb solids}/10^6 \text{ lb water} \times 60 \text{ min/hr} = \underline{3.38 \text{ lb/hr}}$$

On an annual basis, this is equivalent to almost 15 tons per year (tpy). Even for a state-of-the-art drift eliminator system, this is not a small number, especially if assumed to all be equal to PM₁₀, a regulated criteria pollutant. However, as the following analysis demonstrates, only a very small fraction is actually PM₁₀.

COMPUTING THE PM₁₀ FRACTION

Based on a representative drift droplet size distribution and TDS in the water, the amount of solid mass in each drop size can be calculated. That is, for a given initial droplet size, assuming that the mass of dissolved solids condenses to a spherical particle after all the water evaporates, and assuming the density of the TDS is equivalent to a representative salt (e.g., sodium chloride), the diameter of the final solid particle can be calculated. Thus, using the drift droplet size distribution, the percentage of drift mass containing particles small enough to produce PM₁₀ can be calculated. This method is conservative as the final particle is assumed to be perfectly spherical; hence as small a particle as can exist.

The droplet size distribution of the drift emitted from the tower is critical to performing the analysis. Brentwood Industries, a drift eliminator manufacturer, was contacted and agreed to provide drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull², 1999). The data consist of water droplet size distributions for a drift eliminator that achieved a tested drift rate of 0.0003 percent. As we are using a 0.0006 percent drift rate, it is reasonable to expect that the 0.0003 percent drift rate would produce smaller droplets, therefore,

this size distribution data can be assumed to be conservative for predicting the fraction of PM₁₀ in the total cooling tower PM emissions.

In calculating PM₁₀ emissions the following assumptions were made:

- Each water droplet was assumed to evaporate shortly after being emitted into ambient air, into a single, solid, spherical particle.
- Drift water droplets have a density (ρ_w) of water; 1.0 g/cm³ or 1.0 * 10⁻⁶ µg / µm³.
- The solid particles were assumed to have the same density (ρ_{TDS}) as sodium chloride, (i.e., 2.2 g/cm³).

Using the formula for the volume of a sphere, $V = 4\pi r^3 / 3$, and the density of pure water, $\rho_w = 1.0 \text{ g/cm}^3$, the following equations can be used to derive the solid particulate diameter, D_p , as a function of the TDS, the density of the solids, and the initial drift droplet diameter, D_d :

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3 \quad [2]$$

$$\text{Mass of solids in drift droplet} = (\text{TDS})(\rho_w)(\text{Volume of drift droplet}) \quad [3]$$

substituting,

$$\text{Mass of solids in drift} = (\text{TDS})(\rho_w)(4/3)\pi(D_d/2)^3 \quad [4]$$

Assuming the solids remain and coalesce after the water evaporates, the mass of solids can also be expressed as:

$$\text{Mass of solids} = (\rho_{TDS})(\text{solid particle volume}) = (\rho_{TDS})(4/3)\pi(D_p/2)^3 \quad [5]$$

Equations [4] and [5] are equivalent:

$$(\rho_{TDS})(4/3)\pi(D_p/2)^3 = (\text{TDS})(\rho_w)(4/3)\pi(D_d/2)^3 \quad [6]$$

Solving for D_p :

$$D_p = D_d [(\text{TDS})(\rho_w / \rho_{TDS})]^{1/3} \quad [7]$$

Where,

TDS is in units of ppmw

D_p = diameter of solid particle, micrometers (µm)

D_d = diameter of drift droplet, µm

Using formulas [2] – [7] and the particle size distribution test data, Table 1 can be constructed for drift from a wet cooling tower having the same characteristics as our example; 7,700 ppmw TDS and a 0.0006% drift rate. The first and last columns of this table are the particle size distribution derived from test results provided by Brentwood Industries. Using straight-line interpolation for a solid particle size 10 µm in diameter, we conclude that approximately 14.9 percent of the mass emissions are equal to or smaller than PM₁₀. The balance of the solid

particulate are particulate greater than 10 μm . Hence, PM_{10} emissions from this tower would be equal to PM emissions x 0.149, or 3.38 lb/hr x 0.149 = 0.50 lb/hr. The process is repeated in Table 2, with all parameters equal except that the TDS is 11,000 ppmw. The result is that approximately 5.11 percent are smaller at 11,000 ppm. Thus, while total PM emissions are larger by virtue of a higher TDS, overall PM_{10} emissions are actually lower, because more of the solid particles are larger than 10 μm .

Table 1. Resultant Solid Particulate Size Distribution (TDS = 7700 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2] ¹	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4189	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65450	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381704	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150347	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767146	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305995	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137167	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449298	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510322	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449847	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097336	1.13E+02	8.71E-01	395840.67	91.098	100.000

¹ Bracketted numbers refer to equation number in text.

The percentage of PM_{10}/PM was calculated for cooling tower TDS values from 1000 to 12000 ppmw and the results are plotted in Figure 1. Using these data, Figure 2 presents predicted PM_{10} emission rates for the 146,000 gpm example tower. As shown in this figure, the PM emission rate increases in a straight line as TDS increases, however, the PM_{10} emission rate increases to a maximum at around a TDS of 4000 ppmw, and then begins to decline. The reason is that at higher TDS, the drift droplets contain more solids and therefore, upon evaporation, result in larger solid particles for any given initial droplet size.

CONCLUSION

The emission factors and methodology given in EPA's AP-42¹ Chapter 13.4 *Wet Cooling Towers*, do not account for the droplet size distribution of the drift exiting the tower. This is a critical factor, as more than 85% of the mass of particulate in the drift from most cooling towers will result in solid particles larger than PM_{10} once the water has evaporated. Particles larger than PM_{10} are no longer a regulated air pollutant, because their impact on human health has been shown to be insignificant. Using reasonable, conservative assumptions and a realistic drift

droplet size distribution, a method is now available for calculating realistic PM₁₀ emission rates from wet mechanical draft cooling towers equipped with modern, high-efficiency drift eliminators and operating at medium to high levels of TDS in the circulating water.

Table 2. Resultant Solid Particulate Size Distribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2] ¹	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4189	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65450	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381704	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150347	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767146	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305995	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137167	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449298	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510322	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449847	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097336	1.13E+02	1.24E+00	565486.68	102.599	100.000

Figure 1: Percentage of Drift PM that Evaporates to PM₁₀

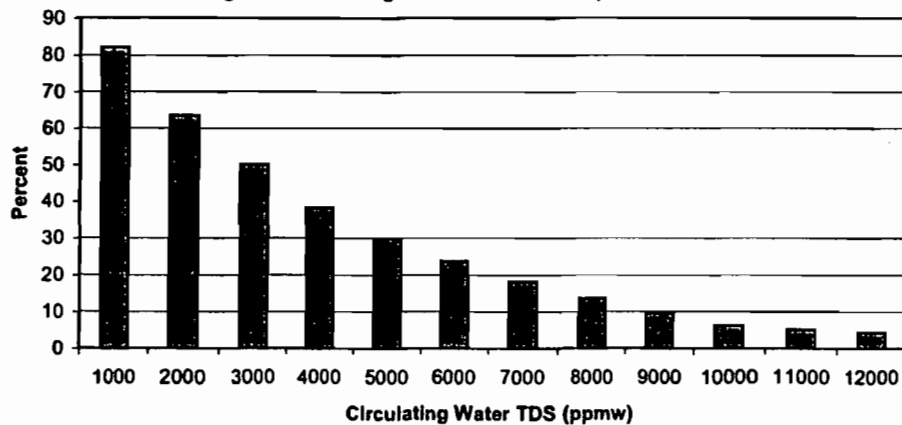
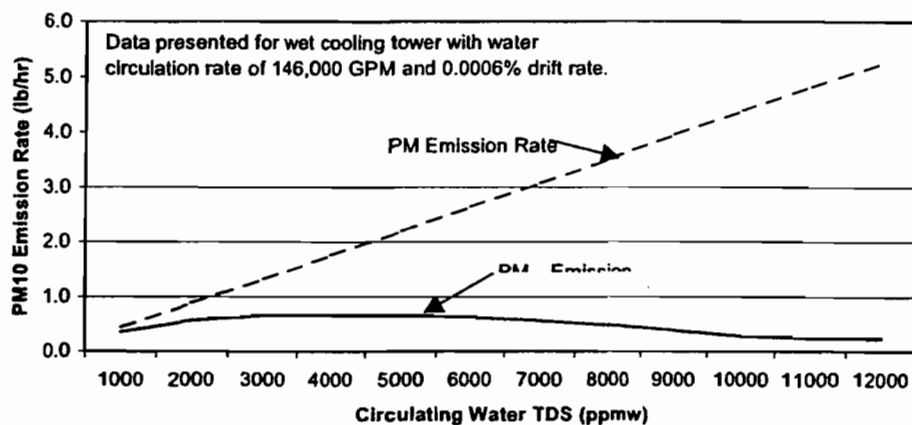


Figure 2: PM₁₀ Emission Rate vs. TDS



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KEY WORDS

Drift
Drift eliminators
Cooling tower
PM₁₀ emissions
TDS

APPENDIX B

**BEST AVAILABLE CONTROL TECHNOLOGY FOR
THE PROPOSED COMBUSTION TURBINES**

B.1 NEW SOURCE PERFORMANCE STANDARDS

BACT is a case-by-case emission limitation for each applicable pollutant, based on the maximum degree of emission reduction after taking into account the energy, environmental, and economic impacts, and other costs. The BACT cannot be any less stringent than any applicable new source performance standards (NSPS) and consideration must be given to the applicable NSPS in the determination of BACT. This requirement also applies for any applicable National Emission Standard for Hazardous Air Pollutants promulgated under 40 CFR Part 61. For combustion turbines the applicable NSPS is 40 CFR Part 60, Subpart GG Standards of Performance for Stationary Gas Turbines.

B.1.1 SUBPART GG

The NSPS regulations (40 CFR, Subpart GG) applicable to gas turbines apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100×10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100×10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the combustion turbines proposed for the project and are the most stringent provision of the NSPS. These requirements are summarized in Table B-1 and were considered in the BACT analysis.

As noted from Table B-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.03 percent, the NSPS is increased by 0.0012 percent or 12 parts per million (ppm). The NSPS NO_x emission limit adjustment is not affected by natural gas combustion.

B.1.2 SUBPART DA

On September 16, 1998, the NSPS for fossil fuel fired steam electric generators with more than 250 MMBtu/hr heat input were updated to include generally more stringent emission limitations for NO_x. These revised NSPS (Subpart Da) apply to any affected facility, which commenced construction after July 9, 1997. The applicable NO_x NSPS limit for firing coal, oil or natural gas, or a mixture of these, or any other fuels, is 1.6 lb/MW [40 CFR 60.44a(d)(1)]. These NSPS are applicable to the project.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

The "top-down" analysis for determining BACT, as provided for in EPA's Draft 1990 New Source Review Workshop Manual was considered in evaluating BACT for the Project. The procedure involves 5 steps: identification of control technologies, elimination of technically infeasible control technologies, a ranking of the control technologies, an evaluation of the effective control technologies and the selection of BACT.

The identification of control technologies is developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina. While these data are comprehensive it is often not up to date with the most recent BACT/LAER decisions and separate contact with state agencies is required. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

The elimination of infeasible technologies is based on those engineering aspects that would preclude a technology's use due to physical, chemical or other engineering consideration. Control technologies that are technically feasible are ranked by control effectiveness, with determination of the environmental, economic and energy costs and benefits of the control technologies. This information forms the basis for the case-by-case consideration of environmental, energy and

economic impacts. The "top" feasible control alterable is selected unless it can be rejected based on economic, environmental or energy considerations. This section of Appendix B presents information related to the proposed BACT emission limitation.

B.2.1 NITROGEN OXIDES

Identification of NO_x Control Technologies

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table B-2 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines including duct firing. This table was developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina.

Historically, the most stringent NO_x controls for CTs established as LAER/BACT by state agencies were combustion controls with selective catalytic reduction (SCR) and combustion controls alone. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process. When SCR has been employed, dry low-NO_x combustion technology is used to minimize the NO_x emissions formed in the combustion process.

Wet injection was the first combustion technology introduced for combustion turbines (pre-1980's) and was the primary method of reducing NO_x emissions from CTs prior to the 1990's. Indeed, this method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O₂ and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15 percent O₂) when burning natural gas. Wet injection is still the only means of reducing NO_x formation in the combustion process when firing oil.

The dry low-NO_x combustion technology has been developed and made available since the early 1990's for gas turbines to achieve emission levels of 25 ppmvd corrected to 15 percent O₂. More recently, however, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 9 ppmvd (corrected to 15 percent O₂) when firing natural gas.

SCR is an available and demonstrated control technology for NO_x control on combined cycle units, which has been installed or permitted in over 100 projects. Beginning in the late 1980s and early 1990s, SCR was initially installed on cogeneration facilities with capacities of 50 MW or less. Most of these projects were in California. Many of these initial SCR projects were located in the Southern California NO₂ nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. As noted previously, there are distinct regulatory and policy differences between LAER and BACT. As discussed in Section 3.0, BACT involves an evaluation of the economic, environmental, and energy impacts of alternative control technologies. In contrast, LAER only considers the technical aspects of control.

More recently, projects with SCR have been installed throughout the US. A majority of these projects are natural gas-fired combined cycle facilities. The size of these projects ranges from 22 MW to over 500 MW. While many of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to over 80 percent of NO_x in the exhaust gas stream. The most common BACT emission limiting standard over the last two years is 3.5 ppmvd corrected to 15 percent O₂ or less for natural gas firing when using DLN and SCR. The most common emission limiting standard established as LAER is 2.5 ppmvd corrected to 15 percent O₂ or less for natural gas firing and using SCR.

Other available control technologies that have become available for controlling NO_x emissions from combustion turbines include SCONO_xTM and XONONTM. SCONO_xTM is an add-on control using absorption and chemical conversion to remove NO_x formed from combustion, while XONONTM is a catalytic combustion system integral to the turbine. Other potential technologies used in combustion process for NO_x removal include: NO_xOUT, Thermal DeNO_x, and NSCR.

Technology Descriptions and Feasibility

Wet Injection

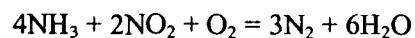
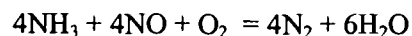
The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion results (i.e., CO and VOC emissions). In "F" Class turbines using wet injection with gas firing, the NO_x emission rates in the range of 30 ppm have been demonstrated. However, wet injection is no longer offered for gas firing in "F" Class turbines. Wet injection is the only current feasible means of reducing NO_x emissions in the combustion process when firing oil.

Dry Low-NO_x Combustor

In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on conventional machines manufactured by General Electric (GE), Siemens Westinghouse, Mitsubishi Heavy Industries (MHI) and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. All these vendors have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level when firing natural gas at baseload conditions is 9 ppmvd (corrected to 15 percent O₂), a level which is guaranteed by the selected vendor for the project.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) uses ammonia (NH₃) to react with NO_x in the gas stream in the presence of a catalyst. NH₃, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:



SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR

with base metal catalysts. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been primarily limited to combined-cycle facilities that burn natural gas with small amounts of fuel oil. Initially, the traditional metal catalysts used in SCR systems were contaminated by sulfur-containing fuels. For most fuel-oil-burning facilities, catalyst operation was discontinued, or the exhaust bypasses the SCR system. This was due to the formation of ammonium salts (ammonium sulfate and bisulfate) resulting from the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required with concomitant cost and technical requirements. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts. Ceramic and specially designed catalysts have been designed to overcome the problems with base-metal catalysts. The sulfur in No. 2 distillate oil has also been reduced from 0.5 percent available in the early 1990's to 0.05 percent. In addition, HRSG designs can accommodate the impacts of the formation of ammonium salts.

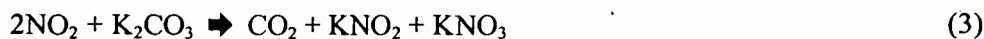
For combined cycle units, SCR is an available, technically feasible and demonstrated technology.

SCONO_x™ Process

SCONO_x™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc. In 1998, ABB acquired the exclusive license for the technology in the United States for control applications larger than 100 MW.

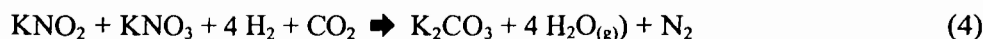
The SCONO_x™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2 . NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The SCONO_x™ oxidation/absorption cycle reactions are:





CO₂ produced by reaction (1) and (2) is released to the atmosphere as part of the CT/HRSG exhaust gas stream.

As shown in Reaction (3), the potassium carbonate catalyst coating reacts with NO₂ to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O₂. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO₂ in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The SCONOXTM regeneration cycle reaction is:

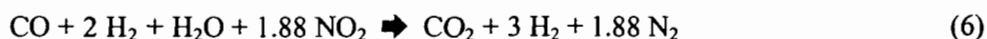
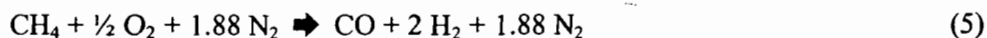


Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the SCONOXTM catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 75 percent of the catalyst sections will be in the oxidation/absorption cycle, while 25 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 5 minutes.

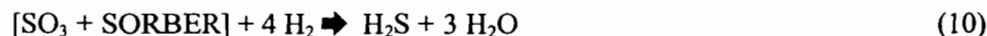
Regeneration gas is produced by reacting natural gas with O₂ present in ambient air. The SCONOXTM system uses a gas generator produced by Surface Combustion. This unit uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and ambient air are reacted across a partial oxidation catalyst at 1,900°F to form CO and hydrogen. Steam is added and the gas mixture is then passed across a low temperature shift catalyst, forming CO₂ and additional hydrogen. The

resulting gas stream is diluted to less than 4 percent hydrogen using steam or another inert gas. The regeneration gas reactions are:



The SCONOXTM operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For SCONOXTM systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONOXTM catalyst that reforms the natural gas.

The SCONOXTM system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SCOSO_xTM) to remove sulfur compounds is installed upstream of the SCONOXTM catalyst. During regeneration of the SCONOXTM catalyst, either hydrogen sulfide or SO₂ is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the SCOSO_xTM process is proprietary. SCOSO_xTM oxidation/absorption and regeneration reactions are:



Utility materials needed for the operation of the SCONOXTM control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the SCONOXTM control system is limited to one small combined cycle (CC) power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine (30 MW size) equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The SCONOXTM control system was installed at

the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmv resulting in an approximate 85 percent NO_x removal efficiency.

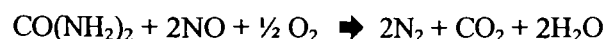
A second SCONO_xTM system was installed at the Genetics Institute Facility in Andover, Massachusetts in late 1998. The system is installed on a 5-MW Caterpillar Solar Turbine with a Deltak boiler. The NO_x emission limit is 2.5 ppmvd at 15-percent O₂. ABB Environmental reports that the system is operating successfully, although there have been incidents of high NO_x emissions that ABB Environmental attributes to combustion control problems and not to the SCONO_xTM system.

XONONTM Catalytic Combustor

Catalytic combustors are being developed for low emission applications on turbines where the catalyst is internal to the combustion system. The XONONTM Combustion System is a catalytic combustion system developed by Catalytica Combustion Systems, Inc. that can achieve low emission levels of NO_x, CO and VOCs. The XONONTM system combusts the fuel over a catalyst, reducing the temperature of combustion and providing for more complete combustion of the fuel. The system is referred to as "flameless combustion" where temperature are below those where limited NO_x formation occurs. However, the exhaust temperatures from a combustion turbine standpoint are still sufficient for the expansion of the gases through the turbine for power generation. Emission levels of NO_x at less than 2 ppm have been reported for the 1.5 MW Kawasaki gas turbine located at Sun Valley Power. Recently, this technology has been proposed for a 750 MW combined cycle facility. This facility, the Pastoria Energy Facility, is a project proposed by affiliates of Enron Corporation, which has a 15 percent interest in Catalytica Combustion Systems, Inc. Commercial operation is scheduled for the summer of 2003. Catalytica is currently working in collaboration with several gas turbine manufacturers including General Electric, Pratt & Whitney, Rolls Royce Allison and Solar.

NO_xOUT Process

The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:



The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x . In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of use of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited and the NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the "F" Class CT is about 1,100°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x .

Thermal De NO_x

Thermal De NO_x is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal De NO_x requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal De NO_x are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There

are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of material requirements, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal DeNO_x process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of an "F" Class combustion turbine is typically 1,100°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction

Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

Technology Demonstration and Feasibility

The combustion controls using dry low-NO_x combustors for the combustion turbine and low-NO_x burners for duct firing are available, demonstrated and technically feasible for combustion turbines in either simple cycle or combined cycle configuration. The dry low-NO_x combustion technology alone can achieve 9 ppm (corrected to 15 percent O₂ dry conditions) when firing natural gas.

The technical evaluation of post-combustion gas controls that include NO_xOUT, Thermal DeNO_x, and NSCR, and indicate that these processes have not been applied to either simple cycle combustion turbines or combined cycle systems and are technically infeasible for the project because of process constraints (e.g., temperature). The SCONO_xTM control technology is available but not considered to be technically feasible because it has not been commercially demonstrated on large "F" Class CTs. The CTs planned for the project, General Electric Frame 7FA units, each have a nominal generating capacity of 170 MW which are approximately seven times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the SCONO_xTM technology given the large differences in machine flow

rates are unknown. Additional concerns with the SCONO_xTM control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, relatively brief operating history of the technology, and distillate oil firing. While the XONONTM catalytic combustion system is applied directly to the combustion turbine, application on a large combined cycle unit has not been demonstrated. For these reasons, the SCONO_xTM and XONONTM are still considered in the commercial demonstration stage. SCR is commercially available, technically feasible and demonstrated for combined cycle units.

For combined cycle operation, the combination of dry low-NO_x combustion technology and water injection with SCR is a technically feasible alternative that can achieve a maximum degree of emission reduction. The combined technology is capable of achieving a NO_x emission levels of 2.5 ppm when firing natural gas (corrected to 15 percent O₂ dry conditions) 10 ppm when firing distillate oil (corrected to 15 percent O₂ dry conditions).

Below is a summary of the technical availability, demonstration and feasibility for the proposed project.

Combined Cycle

<u>Technology</u>	<u>Status</u>
Selective Catalytic Reduction	Available, Demonstrated and Feasible
Dry Low-NO _x Combustors	Available, Demonstrated and Feasible for gas firing
Wet Injection	Available, Demonstrated or Feasible for oil firing
SCONO _x	Available, Not Demonstrated
XONON TM	Not Demonstrated
Thermal De NO _x	Not Available or Feasible
NO _x Out	Not Available or Feasible
NSCR	Not Available or Feasible

SCR Cost Estimates

Tables B-3 and B-4 present the total capital and annualized cost to achieve 3.5 ppmvd corrected to 15 percent oxygen when firing natural gas using SCR and SCONO_xTM applied to combined cycle operation, respectively. The emission rate for oil firing for both SCR and SCONO_xTM is based on 12 ppmvd corrected to 15 percent oxygen. The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993) and vendor based estimates for each control system. Standard EPA recommended cost factors were used. A capital recovery period of 15 years was used for the capital

costs. Tables B-3a and B-4a present the total capital and annualized cost to achieve 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas and 10 ppmvd when firing fuel oil.

Comparison of Economic, Environmental, and Energy Impacts

Table B-5 presents a comparison of the economic, environmental, and energy impacts associated with the top control alternatives to achieve 3.5 ppmvd corrected to 15 percent oxygen when firing gas and 12 ppmvd corrected to 15 percent oxygen when firing oil. Table B-6 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions. Tables B-5a and B-6a present the economic, environmental and energy impacts associated with achieving 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas and 10 ppmvd when firing fuel oil.

B.2.2 CARBON MONOXIDE

Identification of CO Control Technologies

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table B-7 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with combustion controls alone. These installations have been required to use LAER technology and typically have CO limits less than 10 ppmvd (corrected to dry conditions).

Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with an efficiency of 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Oxidation Catalyst Costs

Tables B-8 and B-9 present the capital and annualized cost for an oxidation catalyst installed in the HRSG.

Comparison of Economic, Environmental, and Energy Impacts

Table B-10 presents a comparison of the economic, environmental, and energy impacts associated with the top control alternatives for the combined cycle unit. Table B-11 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions. The latter results from generation lost due to the back pressure of the oxidation catalyst. The maximum CO impacts are less than 0.5 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as reducing acidic deposition, to reducing CO.

Table B-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation ^a
Nitrogen Oxides ^b	0.0075 percent by volume (75 ppm) at 15 percent O ₂ on a dry basis adjusted for heat rate and fuel nitrogen
^a Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10 ⁶ Btu/hr. ^b Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:	
Fuel-Bound Nitrogen (percent by weight)	Allowed Increase NO _x Percent by Volume
N ≤ 0.015	0
0.015 < N ≤ 0.1	0.04(N)
0.1 < N ≤ 0.25	0.004 + 0.0067(N - 0.1)
N > 0.25	0.005

where: N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO _x Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR; WI		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NO _x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmBtu NG/FO - GE; 0.013/0.046 lb/mmBtu	SCR/WI		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu)	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
Tenaska Alabama IV Partners	AL	Oct-01	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - \$6,145/ton NO _x ; CatOx-\$1,506/ton CO
Duke Energy Autauga, LLC	AL	Oct-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$18760/ton NO _x ; CatOx-\$5,006/ton CO
Duke Energy Dale, LLC	AL	Dec-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		SCONOx - \$18,403/ton NO _x ; CatOx-\$2,634/ton CO+VOC
Barton Shoals Energy, LLC	AL	Jul-02	1,200	4	4	GE 7FA (170 MW)	NG	CC	8,760	2.5 ppm (0.0092 lb/mmBtu)	SCR		EPA did not received application until 5/24/02
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	Netting out of PSD for NO _x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD review for NO _x

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO _x Limit	Control Method	Avg. Time	Comments
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	SCONOX - \$16,712/ton NO _x ; CatOx - \$2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		SCONOX - no cost eval.; CatOx - \$4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		Repowering project: netting out of NO _x , CO, PM ₁₀ and SO ₂ review (subject to VOC review)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		base/duct burner/power aug./60-70% load; SCONOX - \$9,982/ton NO _x ; CatOx - \$1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	Mar-02	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		
Broward Energy Center	FL	May-02	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	Aug-02	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	Jan-02	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Repowering Project: Netting out of PSD for NO _x , SO ₂ , VOC, lead and SAM (subject for PM ₁₀ and CO)
CPV Cana Power Generation Facility	FL	01/17/2002	245	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR		PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FPL Martin	FL	04/16/2003	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	2.5 ppm NG; 10 ppm FO/9-15 ppm NG; 42 ppm FO	SCR/DLN; WI		PA = Power Augmentation
FPL Manatee	FL	04/15/2003	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	2.5 ppm CC/9-15 ppm SC	SCR/DLN		PA = Power Augmentation
FPC - Hines Energy Complex	FL	draft permit	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG/ 10 ppm FO	SCR		SCONOX - \$8,597/ton NO _x ;
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Buffalo Creek, LLC	GA	Oct-00	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		SCONOX - \$19,948/ton NO _x ; CatOx - \$2,469/ton CO
Augusta Energy LLC	GA	Oct-00	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONOX - \$17,490/ton NO _x ; CatOx - \$4,133/ton CO

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO _x Limit	Control Method	Avg. Time	Comments
GenPower Rincon	GA	Dec-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Effingham Power Co.	GA	Dec-00	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	Feb-01	1,550	6	4	F* Class	NG	CC/SC	8,760/2,500	3.5/9 ppm	SCR/DLN;		
CPV Terrapin, LLC	GA	Jun-01	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 5.4 ppm (NG w/DB); 8.0 ppm FO	SCR		
Savannah Electric and Power - Plant McIntosh	GA	04/17/2003	1,260	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.5 ppm NG; 6 ppm FO	SCR		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
Live Oak Co., LLC	GA	applic. under review	600	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Pecan Grove Generating	GA	applic. under review	550	2	2	SW 501FD (175 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm NG; 12. ppm FO	SCR		
Big River Power, LLC	GA	applic. under review	855	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	3.0 ppm NG; 8.0 ppm FO	SCR/DLN; WI		SCR - \$5,075/ton NO _x ; CatOx - \$4,712/ton CO
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
Duke Energy Trimble	KY	applic. under review	1,240	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm	SCR		
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Cogentrix Energy, Southaven Power Project	MS	Apr-00	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/DB)	DLN/SCR		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		revised application to add SCR
GenPower - McAdams LLC	MS	Aug-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
Lone Oak Energy Center	MS	Nov-01	800	3	3	F* Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
Lee Power Partners	MS	Mar-01	1,000	4	4	F* Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
LSP-Pike Energy LLC	MS	Nov-00	1,100	4	4	F* Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
Magnolia Energy	MS	May-01	900	3	3	F* Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	3.5 ppm	DLN, SCR		
Reliant Energy - Choctaw Co., LLC	MS	Jun-01	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	SCONox - \$48,663/ton NO _x ; CatOx - \$3,550/ton CO
Crossroads Energy Center	MS	Jun-02	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONox - \$23,400/ton NO _x ; CatOx - \$11,039/ton CO
Choctaw Gas Generation, LLC	MS	Dec-01	700	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	
Granite Power Partners II (Batesville)	MS	Nov-01	300	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR		
Panada Black Prairie LP	MS	applic. under review	1,040	4	4	F* Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR		GE7FA or SW501F
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	Nov-99	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
GenPower Earleys, LLC	NC	Jan-02	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONox - \$21,942/ton NO _x ; CatOx - \$3,246/ton CO

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO _x Limit	Control Method	Avg. Time	Comments
Mirant Gastonia	NC	05/28/2002	1,200	4	4	"F" Class (175 MW)	NG	CC	8,760	2.5/3.5 ppm	SCR		CO Limit depends on CT model; NO _x limit depends on operating history and 3.3 ppm trigger level
Carolina Plant	NC	applic. under review	1,300	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	2.5/3.5 ppm; 13/18 ppm	SCR		CO Limit depends on CT model; NO _x limit depends on operating history and 3.3 ppm trigger level
Mountain Creek - Granville Energy Center	NC	applic. under review	911	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONox - \$22,600/ton NO _x ; CatOx - \$3,560/ton CO
Dominion Person, Inc.	NC	applic. under review	1,100	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm; 15 ppm FO	SCR		
Forsyth Energy Project	NC	applic. under review	812	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	2.5/3.5 ppm NG; 13/18 ppm FO	SCR		CO Limit depends on CT model; NO _x limit depends on operating history and 3.3/17 ppm trigger levels
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		Netted out of NO _x , SO ₂ and PM ₁₀ PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		SCONox - no analysis; CatOx - \$1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	3.5 ppm	DLN/SCR		
Greenville Power Project	SC	applic. under review	810	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 20 ppm FO	SCR		SCONox - \$18,300/ton NO _x ; CatOx - \$5,800/ton CO; DB < 5,120 hr/yr
Jasper County Generating Facility	SC	05/28/2002	1,260	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	2.5 ppm NG; 7.5 ppm FO	SCR		SCONox - \$19,870/ton NO _x ; CatOx - \$3,320/ton CO
Cherokee Falls Combined-Cycle Facility	SC	applic. under review	1,260	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONox - \$22,434/ton NO _x ; CatOx - \$2,500/ton CO
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR		
Palmetto Energy Center	SC	applic. under review	970	3	3	GE 7FB (180 MW)	NG	CC	8,760	3.5 ppm	SCR		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		
Memphis Generation LLC	TN	Apr-01	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	Feb-02	900	3	3	SW, GE 7FA or GE	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TVA - Franklin	TN	draft permit	610	2	2	GE 7FA (195 MW)		CC	8,760	3.5 ppm	SCR		
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	3.5/9 ppm NG; 12/42 ppm FO	SCR/DLN: SCR/WI		

Abbreviations:

GE = General Electric
SW = Siemens WestinghouseNG = Nat. Gas
FO = Fuel Oil
DB = Duct BurnerSC = Simple Cycle
CC = Combined CycleDLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic ReductionCatOx = Catalytic Oxidation
GCP = Good Combustion PracticesSource: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOX™ for the GE Frame 7FA Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOX™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	\$1,059,603	\$14,750,000	Vendor Estimates
Ammonia Storage Tank	\$123,865	\$0	\$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	\$44,505	\$69,725	Vatavauk, 1990
Instrumentation	\$50,000	\$50,000	Additional NO _x Monitor and System
Taxes	\$63,576	\$885,000	6% of SCR Associated Equipment and Catalyst
Freight	\$52,980	\$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	\$1,394,530	\$16,492,225	
Direct Installation Costs			
Foundation and supports	\$111,562	1,319,378	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	\$195,234	2,308,912	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	\$55,781	659,689	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping	\$27,891	329,845	2% of TDCC and RCC; OAQPS Cost Control Manual
Insulation for ductwork	\$13,945	164,922	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	\$13,945	164,922	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation	\$5,000	\$5,000	Engineering Estimate
Buildings	\$15,000	\$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	\$438,359	\$4,967,668	
Total Capital Costs (TCC)	\$1,832,888	\$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	\$139,453	\$1,649,223	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	\$50,000	\$0	Engineering Estimate
Construction and Field Expense	\$69,726	\$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	\$139,453	\$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	\$27,891	\$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	\$13,945	\$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	\$41,836	\$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	\$482,304	\$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	\$2,315,192	\$26,572,482	Sum of TCC and TInCC

Table B-3a. Capital Cost for Selective Catalytic Reduction and SCONOX™ for the GE Frame 7FA Combined Cycle Combustion Turbine
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOX™	Basis of Cost Component
<u>Direct Capital Costs</u>			
Pollution Control Equipment	\$1,165,563	\$14,750,000	Vendor Estimates
Ammonia Storage Tank	\$123,865	\$0	\$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	\$44,505	\$69,725	Vatavauk, 1990
Instrumentation	\$50,000	\$50,000	Additional NO _x Monitor and System
Taxes	\$69,934	\$885,000	6% of SCR Associated Equipment and Catalyst
Freight	\$58,278	\$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	\$1,512,145	\$16,492,225	
<u>Direct Installation Costs</u>			
Foundation and supports	\$120,972	1,319,378	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	\$211,700	2,308,912	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	\$60,486	659,689	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping	\$30,243	329,845	2% of TDCC and RCC; OAQPS Cost Control Manual
Insulation for ductwork	\$15,121	164,922	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	\$15,121	164,922	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation	\$5,000	\$5,000	Engineering Estimate
Buildings	\$15,000	\$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	\$473,644	\$4,967,668	
Total Capital Costs (TCC)	\$1,985,789	\$21,459,893	Sum of TDCC, TDIC and RCC
<u>Indirect Costs</u>			
Engineering	\$151,215	\$1,649,223	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	\$50,000	\$0	Engineering Estimate
Construction and Field Expense	\$75,607	\$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	\$151,215	\$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	\$30,243	\$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	\$15,121	\$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	\$45,364	\$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	\$518,765	\$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	\$2,504,554	\$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOXTM for the GE Frame 7FA in Combined Cycle Operation
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOX TM	Basis of Cost Component
<u>Direct Annual Costs</u>			
Operating Personnel	\$18,720	\$37,440	24 hours/week at \$15/hr for SCR; SCONOX 2 times SCR costs
Supervision	\$2,808	\$5,616	15% of Operating Personnel; OAQPS Cost Control Manual
Ammonia	\$126,898	\$0	\$580 per ton NH ₃ based on 19% Aqueous NH ₃
PSM/RMP Update	\$15,000	\$0	Engineering Estimate
Inventory Cost	\$2,844	\$4,266	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOX 1.5 times SCR
Catalyst Cost	\$77,704	\$116,556	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	\$7,319	\$4,916	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$251,293	\$168,795	
<u>Energy Costs</u>			
Electrical	\$28,032	\$70,080	80kW/h for SCR @ \$0.04/kWh times Capacity Factor; 200 kW for SCONOX
MW Loss and Heat Rate Penalty	\$321,289	\$642,578	0.3 % output for SCR; 0.6% for SCONOX; EPA, 1993
Steam Costs for SCONOX	\$0	\$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; \$3/mmBtu
Natural Gas for SCONOX	\$0	\$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; \$3/mmBtu
Total Energy Costs (TEC)	\$349,321	\$1,451,962	
<u>Indirect Annual Costs</u>			
Overhead	89,055	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	23,152	265,725	1% of Total Capital Costs
Insurance	23,152	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	254,208	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDIC
Total Indirect Annual Costs (TIAC)	\$389,567	\$3,474,942	
Total Annualized Costs	\$990,181	\$5,095,698	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 3.5)	\$3,744	\$19,265	per ton of NO _x Removed
Incremental Cost Effectiveness (9 to 3.5)	\$3,744	\$19,265	per incremental ton of NO _x Removed
	264.50	264.50	tons NO _x removed /year; 3.5 ppmvd corrected to 15% oxygen

Source: Golder 2003, EPA 1993 (Alternative Control Techniques Document--NO_x Emissions from Stationary Gas Turbines, Page 6-20)

Table B-4a. Annualized Cost for Selective Catalytic Reduction and SCONOXTM for the GE Frame 7FA in Combined Cycle Operation
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOX TM	Basis of Cost Component
<u>Direct Annual Costs</u>			
Operating Personnel	\$21,840	\$43,680	28 hours/week at \$15/hr for SCR; SCONOX 2 times SCR costs
Supervision	\$3,276	\$6,552	15% of Operating Personnel; OAQPS Cost Control Manual
Ammonia	\$135,244	\$0	\$580 per ton NH ₃ based on 19% Aqueous NH ₃
PSM/RMP Update	\$15,000	\$0	Engineering Estimate
Inventory Cost	\$3,775	\$5,662	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOX 1.5 times SCR
Catalyst Cost	\$103,135	\$154,702	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	\$8,468	\$6,318	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$290,737	\$216,914	
<u>Energy Costs</u>			
Electrical	\$28,032	\$70,080	80kW/h for SCR @ \$0.04/kWh times Capacity Factor; 200 kW for SCONOX
MW Loss and Heat Rate Penalty	\$385,547	\$670,516	0.36 % output for SCR; 0.6% for SCONOX; EPA, 1993
Steam Costs for SCONOX	\$0	\$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; \$3/
Natural Gas for SCONOX	\$0	\$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; \$3/mmBtu
Total Energy Costs (TEC)	\$413,579	\$1,479,900	
<u>Indirect Annual Costs</u>			
Overhead	96,216	30,139	60% of Operating/Supervision Labor and Ammonia
Property Taxes	25,046	265,725	1% of Total Capital Costs
Insurance	25,046	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	275,000	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	\$421,307	\$3,479,247	
Total Annualized Costs	\$1,125,622	\$5,176,062	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 2.5)	\$3,753	\$17,259	per ton of NO _x Removed
Incremental Cost Effectiveness (3.5 to 2.5)	\$3,826	\$2,270	per incremental ton of NO _x Removed
	299.90	299.90	tons NO _x removed /year; 2.5 ppmvd corrected to 15% oxygen

Source: Golder 2000. EPA 1993 (Alternative Control Techniques Document--NO_x Emissions from Stationary Gas Turbines, Page 6-20)

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (3.5 ppmvd corrected)	DLN with SCONOx™ (3.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact ^a			
Capital Costs	included	\$2,315,192	\$26,572,482
Annualized Costs	included	\$990,181	\$5,095,698
Cost Effectiveness (per ton of Nox removed)			
Total	NA	\$3,744	\$19,265
Environmental Impact ^b			
Total NOx (TPY)	398	133.4	133.4
NOx Reduction (TPY)	NA	-265	-265
Ammonia Emissions (TPY)	0	111	0
PM Emissions (TPY)	0	9.6	0
Secondary Emissions (TPY)	0	6.2	41.3
Net Emission Reduction (TPY)	NA	-138	-223
Addition Greenhouse Gas (as CO2; tons/year)	0	3,413	22,901
Energy Impacts ^c			
Energy Use (kWh/yr) - Total	0	5,232,523	35,108,528
Energy Use (kWh/yr) - Back Pressure	0	4,531,723	9,063,446
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	436	2,926
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	53,891	361,591
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	54	362
Energy Use (percent of combustion turbine output)	0	0.35%	2.32%

^a See Tables B-3, B-4, and B-5 for detailed development of capital costs (including recurring costs) and annualized costs.

^b See emission data presented in Table B-7.

^c Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.3 percent of 166 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-5a. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (2.5 ppmvd corrected)	DLN with SCONOx™ (2.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact ^a			
Capital Costs	included	\$2,504,554	\$26,572,482
Annualized Costs	included	\$1,125,622	\$5,176,062
Cost Effectiveness (per ton of Nox removed)			
Incremental from 3.5 ppm	NA	\$3,826	\$2,270
Environmental Impact ^b			
Total NOx (TPY)	398	98.0	98.0
NOx Reduction (TPY)	NA	300	300
Ammonia Emissions (TPY)	0	111	0
PM Emissions (TPY)	0	9.8	0
Secondary Emissions (TPY)	0	7.2	43.5
Net Emission Reduction (TPY)	NA	-172	-256
Additional Greenhouse Gas (as CO ₂ ; tons/year)	0	4,004	24,083
Energy Impacts ^c			
Energy Use (kWh/yr)	0	6,138,868	36,921,218
Energy Use (kWh/yr) - Back Pressure	0	5,438,068	10,876,136
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	512	3,077
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	63,226	380,260
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	63	380
Energy Use (percent of combustion turbine output)	0	0.41%	2.44%

^a See Tables B-3a, B-4a, and B-5a for detailed development of capital costs (including recurring costs) and annualized costs.

^b See emission data presented in Table B-7a.

^c Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.345 percent of 166 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOX™

Pollutants	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOX™		
	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	9.55	0.20	9.75		1.31	1.31
Sulfur Dioxide		0.07	0.07		0.49	0.49
Nitrogen Oxides	-264.50	3.59	-260.91	-264.50	24.11	-240.40
Carbon Monoxide		2.16	2.16		14.46	14.46
Volatile Organic Compounds		0.14	0.14		0.95	0.95
Ammonia	111.26					
Total:	-143.69	6.16	-137.53	-264.50	41.32	-223.19
Carbon Dioxide (all energy requirements)		3,413.10	3,413.10		22,900.76	22,900.76

Basis:	SCR	SCONOX™	SCONOX™
Lost Energy (mmBtu/year)	53,891	361,591 total	245,607 steam and natural gas only
Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.			
Particulate	0.0072		
Sulfur Dioxide	0.0027		
Nitrogen Oxides w/LNB	0.1333		
Carbon Monoxide	0.0800		
Volatile Organic Compounds	0.0052		

(Note: Secondary emissions of criteria pollutants for SCONOX based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO₂ will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6a. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOXTM
(2.5 ppm)

Pollutants	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOX TM		
	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	9.55	0.23	9.78		1.38	1.38
Sulfur Dioxide		0.09	0.09		0.52	0.52
Nitrogen Oxides	-299.90	4.22	-295.68	-299.90	25.35	-274.55
Carbon Monoxide		2.53	2.53		15.21	15.21
Volatile Organic Compounds		0.17	0.17		1.00	1.00
Ammonia	111.26					
Total:	-179.09	7.22	-171.86	-299.90	43.45	-256.45
Carbon Dioxide (all energy requirements).		4,004.29	4,004.29		24,083.15	24,083.15

Basis:	SCR	SCONOX TM	SCONOX TM
Lost Energy (mmBtu/year)	63,226	380,260 total	245,607 steam and natural gas only
Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.			
Particulate	0.0072		
Sulfur Dioxide	0.0027		
Nitrogen Oxides w/LNB	0.1333		
Carbon Monoxide	0.0800		
Volatile Organic Compounds	0.0052		

(Note: Secondary emissions of criteria pollutants for SCONOX based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NO _x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.089 lb/mmBtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmBtu (base/PA/FO) - Mit	GCP		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
Tenaska Alabama IV Partners	AL	Oct-01	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONox - \$6,145/ton NO _x ; CatOx - \$1,506/ton CO
Duke Energy Autauga, LLC	AL	Oct-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONox - \$18760/ton NO _x ; CatOx - \$5,006/ton CO
Duke Energy Dale, LLC	AL	Dec-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	0.033 lb/mmBtu	GCP		SCONox - \$18,403/ton NO _x ; CatOx - \$2,634/ton CO+VOC
Barton Shoals Energy, LLC	AL	Jul-02	1,200	4	4	GE 7FA (170 MW)	NG	CC	8,760	10 ppm (0.022 lb/mmBtu); 0.041 lb/mmBtu w/DB	GCP		EPA did not received application until 5/24/02
Kissimmee Utility Authority, Cane Island Power Park - Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NO _x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NO _x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,890 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONox - \$16,712/ton NO _x ; CatOx - \$2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONox - no cost eval.; CatOx - \$4,350/ton CO

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NO _x , CO, PM ₁₀ and SO ₂ review (subject to VOC review)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONO _x - \$9,982/ton NO _x ; CatOx - \$1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	Mar-02	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	12.21/14.17 ppm	GCP		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG (15 ppm w/PA); 20 ppm FO	GCP		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
Broward Energy Center	FL	May-02	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA); 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (7.8 ppm)	GCP	24-hr (3-hr test)	Repowering Project: Netting out of PSD for NO _x , SO ₂ , VOC, lead and SAM (subject for PM ₁₀ and CO)
CPV Cana Power Generation Facility	FL	01/17/2002	245	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA); 17/19/26 ppm FO	GCP	24-hr	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FPL Martin	FL	04/16/2003	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	10 ppm NG/8 ppm NG (12 ppm w/PA); 15 ppm FO	GCP	24-hr	PA = Power Augmentation
FPL Manatee	FL	04/15/2003	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	10 ppm NG/8 ppm NG (12 ppm w/PA)	GCP	24-hr	PA = Power Augmentation
FPC - Hines Energy Complex	FL	draft permit	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	10 ppm NG/20 ppm FO	GCP	24-hr	SCONO _x - \$8,597/ton NO _x ;
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	21.8 ppm	GCP		
Duke Energy Buffalo Creek, LLC	GA	Oct-00	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	21.9 ppm	GCP		SCONO _x - \$19,948/ton NO _x ; CatOx - \$2,469/ton CO
Augusta Energy LLC	GA	Sep-01	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	17.4 ppm NG; 20 ppm FO	GCP		SCONO _x - \$17,490/ton NO _x ; CatOx - \$4,133/ton CO
GenPower Rincon	GA	Dec-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm/14 (w/DB) ppm	GCP		
Effingham Power Co.	GA	Dec-00	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Peace Valley Generation Co., LLC	GA	draft permit	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	10.6 ppm (25 ppm w/DB)	GCP	24-hr rolling	After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 13.6 ppm (NG w/DB); 24 ppm FO	GCP		
Savannah Electric and Power - Plant McIntosh	GA	04/17/2003	1,260	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.0 ppm	CatOx		
Live Oak Co., LLC	GA	applic. under review	600	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	3-hr	SCR - \$5,075/ton NO _x ; CatOx - \$4,712/ton CO
Pecan Grove Generating	GA	applic. under review	550	2	2	SW 501FD (175 MW)	NG; FO	CC	8,760; 500 FO	15;22.9;25;50 ppm (NG; NG w/DB;NG @70%; FO)	GCP		
Big River Power, LLC	GA	applic. under review	855	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	19.2 ppm (w/DB)/9.0 ppm (w/o DB) NG; 20.0 ppm FO	GCP		
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	GCP	24-hr	revised application to add SCR
Duke Energy Trimble	KY	applic. under review	1,240	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	9/13.9/20 ppm	GCP		
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP	24-hr	Base/PA/PA+DF/DF
Cogentrix Energy, Southaven Power Project	MS	Apr-00	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 18 ppm w/ DB	GCP		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		
GenPower - McAdams LLC	MS	Aug-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Lone Oak Energy Center	MS	Nov-01	800	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		
Lee Power Partners	MS	Mar-01	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
LSP-Pike Energy LLC	MS	Nov-00	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP	24-hr	Modification of previous permit to switch 2 SC -> CC
Magnolia Energy	MS	May-01	900	3	3	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	20 ppm	GCP		
Reliant Energy - Choctaw Co., LLC	MS	Jun-01	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.36 ppm	GCP	24-hr	SCONOx - \$48,663/ton NO _x ; CatOx - \$3,550/ton CO
Crossroads Energy Center	MS	Jun-02	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		
Choctaw Gas Generation, LLC	MS	Dec-01	700	2	2	SW 501G (250 MW)	NG	CC	8,760	23 ppm	GCP		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	20.4 ppm	GCP	24-hr	GE7FA or SW501F
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	25 ppm	GCP		
Panada Black Prairie LP	MS	applic. under review	1,040	4	4	F" Class (175 MW)	NG	CC	8,760	7.6 ppm or 80 ppm	GCP		
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	9 ppm NG; 20 ppm FO	GCP	24-hr	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 41 ppm FO	GCP		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (14 ppm w/DB)	GCP	24-hr block	SCONOx - \$21,942/ton NO _x ; CatOx - \$3,246/ton CO
Mirant Gastonia	NC	05/28/2002	1,200	4	4	"F" Class (175 MW)	NG	CC	8,760	15 or 30 ppm	GCP		

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Carolina Plant	NC	applic. under review	1,300	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	47 or 50 ppm	GCP	24-hr block	CO Limit depends on CT model; NO _x limit depends on operating history and 3.3 ppm trigger level
Mountain Creek - Granville Energy Center	NC	applic. under review	911	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (24.3 ppm w/DB)	GCP		SCONox - \$22,600/ton NO _x ; CatOx - \$3,560/ton CO
Dominion Person, Inc.	NC	applic. under review	1,100	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	9 ppm NG (20 ppm w/DB) 20 ppm FO	GCP		
Forsyth Energy Project	NC	applic. under review	812	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	25.9 ppm NG (w/DB); 25.1 ppm FO (w/DB)	GCP	24-hr block	CO Limit depends on CT model; NO _x limit depends on operating history and 3.3/17 ppm trigger levels
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	12 ppm NG; 20 ppm FO	GCP		Netted out of NO _x , SO ₂ and PM ₁₀ PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	17.4 ppm NG; 37 ppm FO	GCP		SCONox - no analysis; CatOx - \$1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8,760	11.7 ppm	GCP		
Greenville Power Project	SC	applic. under review	810	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	12.3 ppm NG; 16.5 ppm FO	GCP		SCONox - \$18,300/ton NO _x ; CatOx - \$5,800/ton CO; DB < 5,120 hr/yr
Jasper County Generating Facility	SC	05/28/2002	1,260	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)	GCP		SCONox - \$19,870/ton NO _x ; CatOx - \$3,320/ton CO
Cherokee Falls Combined-Cycle Facility	SC	applic. under review	1,260	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	0.063 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		SCONox - \$22,434/ton NO _x ; CatOx - \$2,500/ton CO
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	14 ppm (GE7FA/16 ppm (SW501F)	GCP	24-hr	
Palmetto Energy Center	SC	applic. under review	970	3	3	GE 7FB (180 MW)	NG	CC	8,760	15 ppm (31 ppm w/DB)	GCP		SCONox - \$18,789/ton NO _x ; CatOx - \$2,111/ton CO
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	GCP		
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	25 ppm	GCP		
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	0.035 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		

Abbreviations:

GE = General Electric
SW = Siemens WestinghouseNG = Nat. Gas
FO = Fuel Oil
DB = Duct BurnerSC = Simple Cycle
CC = Combined CycleDLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic ReductionCatOx = Catalytic Oxidation
GCP = Good Combustion PracticesSource: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
<u>Direct Capital Costs</u>		
CO Associated Equipment	\$627,009	Vendor Quote
Flue Gas Ductwork	\$44,505	Vatavauk, 1990
Instrumentation	\$62,701	10% of SCR Associated Equipment
Sales Tax	\$37,621	6% of SCR Associated Equipment/Catalyst
Freight	\$31,350	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	\$803,186	
<u>Direct Installation Costs</u>		
Foundation and supports	\$64,255	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	\$112,446	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	\$32,127	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping	\$16,064	2% of TDCC and RCC; OAQPS Cost Control Manual
Insulation for ductwork	\$8,032	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	\$8,032	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation	\$5,000	Engineering Estimate
Buildings	\$0	
Total Direct Installation Costs (TDIC)	\$245,956	
Total Capital Costs	\$1,049,142	Sum of TDCC, TDIC and RCC
<u>Indirect Costs</u>		
Engineering	\$104,914	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	\$52,457	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	\$104,914	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	\$20,983	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	\$10,491	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	\$31,474	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	\$325,234	
Total Direct, Indirect and Capital Costs (TDICC)	\$1,374,376	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
<u>Direct Annual Costs</u>		
Operating Personnel	\$6,240	8 hours/week at \$15/hr
Supervision	\$936	15% of Operating Personnel; OAQPS Cost Control Manual
Catalyst Replacement	\$185,780	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	\$24,668	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	\$6,529	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$224,154	
<u>Energy Costs</u>		
Heat Rate Penalty	\$214,193	0.2% of MW output; EPA, 1993 (Page 6-20) and \$3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	\$214,193	
<u>Indirect Annual Costs</u>		
Overhead	\$4,306	60% of Operating/Supervision Labor
Property Taxes	\$13,744	1% of Total Capital Costs
Insurance	\$13,744	1% of Total Capital Costs
Annualized Total Direct Capital	\$150,906	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	\$182,700	
Total Annualized Costs	\$621,046	Sum of TDAC, TEC and TIAC
Cost Effectiveness	\$4,240	per ton of CO Removed
	\$4,657	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN Only	DLN with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact ^a		
Capital Costs	included	\$1,374,376
Annualized Costs	included	\$621,046
Cost Effectiveness		
CO Removed (per ton of CO)	NA	\$4,240
Environmental Impact ^b		
Total CO (TPY)	175	28
CO Reduction (TPY)	NA	-145
Net Pollutant Reduction	NA	-133
Additional Greenhouse Gas (CO ₂ ; tons/yr)	--	1,971
Energy Impacts ^c		
Energy Use (kWh/yr)	0	3,021,149
Energy Use (Equivalent Residential Customers/year)	0	252
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	31,116
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	31

^a See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

^b See emission data presented in Table B-11.

^c Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year.

Lost energy is based on 0.2 percent of 166 MW.

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Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

Pollutants	Incremental Emissions (tons/year) of SCR		Total
	Primary	Secondary	
Particulate	9.55	0.11	9.66
Sulfur Dioxide		0.04	0.04
Nitrogen Oxides	0.00	2.07	2.07
Carbon Monoxide	-146.5	1.24	-145.2
Volatile Organic Compounds		0.08	0.08
Total:	-136.9	3.56	-133.4
Carbon Dioxide (additional from gas firing)		1,970.6	1,970.6

Basis:

Lost Energy (mmBtu/year) 31,116

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate 0.0072

Sulfur Dioxide 0.0027

Nitrogen Oxides w/LNB 0.1333

Carbon Monoxide 0.0800

Volatile Organic Compounds 0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

APPENDIX C

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

C.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new major sources or major modifications to those sources are required to address air quality impacts at PSD Class I areas. As part of the PSD analysis report submitted to the Florida Department of Environmental Protection (DEP), the air quality impacts due to the potential emissions of the proposed Project at the Turkey Point Plant are required to be addressed at the PSD Class I area of the Everglades National Park (NP). The Everglades NP is located approximately 20.8 km to the west of the Turkey Point Plant and is the only PSD Class I area within 200 km of the plant. The Everglades NP also extends more than 100 km from the plant site.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

Currently there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report*, USFS, NPS, USFWS (12/00), referred to as the FLAG document.

For the Project, air quality analyses were performed that assess the Project's impacts in the PSD Class I area of the Everglades NP using the refined modeling approach from the IWAQM Phase 2 report for:

- SO₂ and PM₁₀ PSD Class I increment analysis;
- Regional haze analysis; and
- Sulfur and nitrogen deposition.

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, include more detailed meteorological data, and are estimated at locations at the Class I area.

C.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the long-range transport model, California Puff model (CALPUFF, Version 5.7). At distances beyond 50 km, the ISCST3 model is considered to over-predict air quality impacts, because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. Recently, the FLM have requested that air quality impacts, such as for regional haze, for a source located more than 50 km from a Class I area be predicted using the CALPUFF model. As a result, the regional haze and sulfur and nitrogen deposition analyses were performed using the CALPUFF model to assess the Project's impacts at the Everglades NP.

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG documents.

A regional haze analysis was performed to determine the affect that the facility's emissions will have on background regional haze levels at the Everglades NP. In the regional haze analysis, the change in visual range, as calculated by a deciview change, was estimated for the facility in accordance with the IWAQM recommendations. Based on those recommendations, the CALPUFF model is used to predict the maximum 24-hour average sulfate (SO₄), nitrate (NO₃), and fine particulate (PM₁₀) concentrations as well as ammonium sulfate [(NH₄)₂SO₄] and ammonium nitrate (NH₄NO₃) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the Proposed Project. The results of these analyses are presented in Sections 6.0 and 7.0 of the PSD report.

C.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.7) air modeling system was used to model to assess the Proposed Project's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels and to the regional haze visibility criteria. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.5), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field 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 was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 and FLAG reports.

C.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The IWAQM has recommended approaches for performing a Phase 2 refined modeling analyses that are presented in Table C-1. These approaches involve use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table C-2.

C.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the Project's emission, stack, and operating data as well as 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 were included in the CALPUFF model input. The PSD Analysis Report presents a listing of the facility's emissions and structures included in the analysis.

C.4 RECEPTOR LOCATIONS

For the refined analyses for addressing compliance with the PSD Class I increments, pollutant concentrations were predicted in an array of 126 discrete receptors located at the Everglades NP area. These receptors are the same as those used in the PSD Class I analysis performed for the PSD Analysis Report. For assessing regional haze and sulfur and nitrogen deposition, pollutant impacts were predicted at receptors located within the Everglades NP but more than 50 km from the plant.

C.5 METEOROLOGICAL DATA

C.5.1 REFINED ANALYSIS

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

C.5.2 CALMET SETTINGS

The CALMET settings contained in Table C-3 were used for the refined modeling analysis.

C.5.3 MODELING DOMAIN

A rectangular modeling domain extending 440 km in the east-west (x) direction and 460 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 23.8 degrees north latitude and 83.5 degrees west longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. For the processing of meteorological and geophysical data, the domain contains 111 grid cells in the x-direction and 116 grid cells in the y-direction. The domain grid resolution is 4 km. The air modeling analysis was performed in the UTM coordinate system.

C.5.4 MESOSCALE MODEL – GENERATION 4 AND 5 (MM4/MM5) DATA

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 and MM5 datasets, prognostic wind fields or “guess” fields, for the United States. The hourly meteorological variables used to create these datasets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and have been developed for the MM4 data for 1990 and the MM5 data for 1992, and 1996. The analysis used the MM4 and MM5 data to initialize the CALMET wind field. The 1990 MM4 and 1992 MM5 data have horizontal spacing of 80 km while the 1996 MM5 data have horizontal spacing of 36 km. These data are used to simulate atmospheric variables within the modeling domain.

The MM4 subset domain was provided by FDEP and consisted of a 7 x 7-cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (50,6) to (57,13). These data were processed to create a MM4.DAT file, for input to the CALMET model. The MM5 subset domain was provided by the National Park Service and was processed in a similar manner as the MM4 data.

The MM4 and MM5 data set used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

C.5.5 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from eight NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Orlando, Fort Myers, Daytona Beach, Vero Beach, Key West, Miami, Tampa, and West Palm Beach. A summary of the surface station information and locations are presented in Table C-4. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The surface station data were processed by FDEP into a SURF.DAT file format for CALMET input.

Because the modeling domain extends largely over water, C-Man station data from Venice, Sombrero Key, and Lake Worth was obtained. These data were processed by Florida DEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

C.5.6 UPPER AIR DATA STATIONS AND PROCESSING

The analysis included three upper air NWS stations located in Ruskin, Key West, and West Palm Beach. Data for each station were obtained from the Florida DEP in a format for CALMET input. The data and locations for the upper air stations are presented in Table C-4.

C.5.7 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 23 stations were obtained in NCDC TD-3240

variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table C-5.

C.5.8 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 the U.S. Geographical Survey (USGS) internet website. The DEM data was extracted for the modeling domain grid using the utility program TERREL. Land-use data were also extracted from 1-degree USGS files and processed using utility programs CTGCOMP and CTGPROC. Both the terrain and land use files were combined into a GEO.DAT file for input to CALMET with the MAKEGEO utility program.

Table C-1. Refined Modeling Analyses Recommendations ^a

Model Input/Output	Description
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 sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
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	1. For PSD increments: use highest, second highest 3-hour and 24-hour average SO₂ concentrations; highest, second highest 24-hour average PM₁₀ concentrations; and highest annual average SO₂, PM₁₀ and NO_x concentrations. 2. For haze: process, on a 24-hour basis, compute the source extinction from the maximum increase in emissions of SO₂, NO_x and PM₁₀; compute the daily relative humidity factor [f(RH)], provided from an external disk file; and compute the maximum percent change in extinction using the FLM supplied background extinction data in the FLAG document. 3. For significant impact analysis: use highest annual and highest short-term averaging time concentrations for SO₂, PM₁₀ and NO_x.

^a IWAQM Phase II report (December, 1998) and FLAG document (December, 2000)

Table C-2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO ₂ , SO ₄ , NO _x , HNO ₃ , NO ₃ , PM ₁₀
Chemical Transformation	MESOPUFF II scheme, hourly ozone data
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO ₄ , NO ₃ , PM ₁₀ , SO ₂ , and NO _x ; process for visibility change using Method 2 and FLAG background extinctions
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For deposition: annual average deposition rate For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO ₂ , NO _x , and PM ₁₀ .
Background Values	Ozone: 50 ppb; Ammonia: 1 ppb

^a Recommended values by the Florida DEP.

Table C-3. CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	440 by 460 km, 4 km grid resolution
Vertical Grid	10 layers
Weather Station Data Inputs	8 surface, 3 upper air, 23 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	1990 MM4 data and 1992 MM5 data, 80 km resolution; 1996 MM5 data, 36 km resolution; used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table C-4. Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates			Anemometer Height (m)
			Easting (km)	Northing (km)	Zone	
<u>Surface Stations</u>						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
Miami	MIA	12839	566.82	2857.20	17	7.0
Key West	EYW	12836	424.03	2715.14	17	18.3
West Palm Beach	PBI	12844	587.87	2951.43	17	10.1
<u>Upper Air Stations</u>						
Ruskin	TBW	12842	349.20	3094.28	17	NA
West Palm Beach	PBI	12844	587.87	2951.42	17	NA
Key West	EYW	12836	424.03	2715.14	17	NA

Table C-5. Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM		
		Coordinate		Zone
		Easting (km)	Northing (km)	
Belle Glade HRCN GT 4	80616	528.19	2953.03	17
Boca Raton	80845	588.75	2916.52	17
Canal Point Gate 5	81271	536.43	2971.51	17
Clewiston US Engineers	81654	546.19	2912.73	17
Fort Myers FAA/AP	83186	413.99	2940.71	17
Homestead Exp Stn	84091	550.26	2820.21	17
Key West Intl AP	84570	423.67	2715.51	17
Miami WSCMO Airport	85663	570.20	2856.17	17
Moore Haven Lock 1	85895	491.61	2967.80	17
North New River Canal #	86323	546.58	2912.48	17
Ortona Lock 2	86657	470.17	2962.27	17
Parrish	86880	366.99	3054.39	17
Pennsuco 5 WNW	86988	554.70	2867.81	17
Port Mayaca S I Canal	87293	538.04	2984.44	17
St Lucie New Lock 1	87859	571.04	2999.35	17
St Petersburg	87886	339.61	3071.99	17
Tamiami Trail 40 Mi BEN	88780	517.64	2849.04	17
Tampa WSCMO AP	88788	348.48	3093.67	17
Trail Glade Ranges	89010	551.57	2849.99	17
Venice	89176	357.59	2998.18	17
Venus	89184	467.27	3001.22	17
Vero Beach 4 W	89219	554.27	3056.50	17
West Palm Beach Int AP	89525	589.61	2951.63	17

APPENDIX D

SO₂ AND PM EMISSION DATA FOR BACKGROUND SOURCES

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
0250348	Miami-Dade County RRF										
		Units 1&2	DCRRF12	76.2	3.66	405.4	15.86	26.41	12.32	CON	Yes
		Units 3&4	DCRRF34	76.2	3.66	405.4	15.86	26.41	12.32	CON	Yes
0250020	Tarmac										
		Kiln 1 PSD Baseline	TARMK1B	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	Yes
		Kiln 2 PSD Baseline	TARMK2B	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	Yes
		Kiln 3 PSD Baseline	TARMK3B	61.0	4.57	472.0	10.78	-2.76	-2.76	EXP	Yes
		Kiln 2 PSD	TABMK2	61.0	2.44	422.0	9.10	24.57	24.57	CON	Yes
		Kiln 3 PSD	TARMK3	61.0	4.57	450.0	11.04	51.43	51.43	CON	Yes
0112119	South Broward RRF PSD										
			SBCRRF	59.4	3.96	381.0	18.01	37.91	37.91	CON	Yes
0110037	FPL - Lauderdale										
		CTs 1-4 PSD	LAUDU45	45.7	5.49	438.7	14.60	271.15	271.15	CON	Yes
		4&5 PSD Baseline	FTLAU45B	46.0	4.27	422.0	14.63	-457.00	-457.00	EXP	Yes
0110120	North Broward RRF PSD										
			NBCRRF	58.5	3.96	381.0	18.01	35.40	35.40	CON	Yes
0112545	El Paso Broward										
		Combined Cycle CT CC-1	EPBRCT1	41.1	5.79	359.3	61.13	0.46	0.46	CON	Yes
		Simple Cycle SC-1	EPBRSC1	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-2	EPBRSC2	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-3	EPBRSC3	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
0710019	Lee County RRF PSD										
			LEECORRF	83.8	1.88	388.5	19.81	14.00	14.00	CON	Yes
0990005	Okeelanta ^a										
		Boiler 4 PSD Baseline	OKBLR4B	22.9	2.29	333.0	7.36	-10.95	-10.95	EXP	Yes
		Boiler 5 PSD Baseline	OKBLR5B	22.9	2.29	333.0	12.07	-15.64	-15.64	EXP	Yes
		Boiler 6 PSD Baseline	OKBLR6B	22.9	2.29	334.0	8.74	-15.64	-15.64	EXP	Yes
		Boiler 10 PSD Baseline	OKBLR10B	22.9	2.29	334.0	10.35	-17.15	-17.15	EXP	Yes
		Boiler 11 PSD Baseline	OKBLR11B	22.9	2.29	342.0	9.89	-16.79	-16.79	EXP	Yes

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
		Boiler 16 PSD	OKBLR16	22.9	1.52	483.0	22.86	1.47	1.47	CON	Yes
0990332	New Hope Power Partnership (Okeelanta)	Okeelanta Power Blrs 1,2,3 ^b	OKCOGENF	60.7	3.05	450.9	19.39	57.5	57.5	CON	Yes
0710000	FPL Fort Myers	Unit 1 PSD	FMU1	91.8	2.90	422.0	29.90	-585.50	-585.50	EXP	Yes
		Unit 2 PSD	FMU2	121.2	5.52	408.0	19.20	-1334	-1334.0	EXP	Yes
		HRSOs 1 - 6	FMYHR1_6	38.1	5.79	377.6	14.2	3.86	3.9	CON	Yes
0990016	Atlantic Sugar ^a	Unit 1	ASA1	27.4	1.83	346.0	17.97	16.28	16.28	CON	Yes
		Unit 2	ASA2	27.4	1.83	350.0	23.36	16.28	16.28	CON	Yes
		Unit 3	ASA3	27.4	1.83	350.0	21.56	16.02	16.02	CON	Yes
		Unit 4	ASA4	27.4	1.83	344.0	25.16	16.21	16.21	CON	Yes
		Unit 5 PSD ^b	ASA5	27.4	1.68	339.0	19.24	8.41	8.04	CON	Yes
		Unit 1 PSD Baseline	ASA1B	18.9	1.92	506.0	12.70	-17.24	-17.24	EXP	Yes
		Unit 2 PSD Baseline	ASA2B	18.9	1.92	511.0	10.90	-22.50	-22.50	EXP	Yes
		Unit 3 PSD Baseline	ASA3B	21.9	1.83	522.0	17.50	-16.88	-16.88	EXP	Yes
		Unit 4 PSD Baseline	ASA4B	18.3	1.83	344.0	15.00	-10.76	-10.76	EXP	Yes
0510015	Southern Gardens Citrus - PSD	Peel Dryer	SGARDDRY	38.1	1.73	316.0	7.45	5.29	5.29	CON	Yes
		Boilers 1-3	SGARDBLR	16.8	1.22	478.0	14.22	6.88	6.88	CON	Yes
0990568	Lake Worth Utilities	Unit 5, S-5	LAKWTHU5	22.9	3.05	481.0	27.80	14.37	14.37	CON	Yes
0990026	Sugar Cane Growers ^a	Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	41.20	41.20	CON	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	16.20	16.20	CON	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	38.20	38.20	CON	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	27.90	27.90	CON	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	23.50	23.50	CON	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-24.20	-24.20	EXP	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-4.40	-4.40	EXP	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-24.20	-24.20	EXP	Yes
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-16.20	-16.20	EXP	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-51.00	-51.00	EXP	Yes

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
0990594	El Paso Belle Glade										
		Combined Cycle CT CC-1	EPBGLCT	41.1	5.79	359.3	61.13	0.46	0.46	CON	Yes
		Simple Cycle SC-1	EPBGSC1	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-2	EPBGSC2	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-3	EPBGSC3	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
0510003	US Sugar - Clewiston ^c										
		Unit 8	USSBLR8	60.7	3.96	439.00	15.3	22.1	22.10	CON	Yes
		<u>PSD Baseline (On-crop season only)</u>									
		Unit 1 PSD Baseline	USSBRL1B	23.1	1.86	344.0	30.20	-79.86	-58.21	EXP	Yes
		Unit 2 PSD Baseline	USSBLR2B	23.1	1.86	343.0	35.70	-79.86	-58.21	EXP	Yes
		Unit 3 PSD Baseline	USSBLR3B	27.4	2.29	342.0	14.70	-48.30	-33.20	EXP	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-10.30	-10.30	EXP	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-10.30	-10.30	EXP	Yes
		<u>On-crop season future</u>									
		Unit 1	USSBRL1N	65.0	2.44	347.0	19.20	79.54	74.98	CON	Yes
		Unit 2	USSBLR2N	65.0	2.44	338.7	17.32	79.17	74.12	CON	Yes
		Unit 4	USSBLR4N	45.7	2.51	344.3	24.05	22.49	4.54	CON	Yes
		Unit 7	USSBLR7N	68.6	2.59	405.4	23.60	17.39	15.81	CON	Yes
		<u>Off-crop season future</u>									
		Unit 1	USSBRL1F	65.0	2.44	347.0	17.70	51.64	41.23	CON	Yes
		Unit 2	USSBLR2F	65.0	2.44	338.7	16.19	51.27	37.22	CON	Yes
		Unit 4	USSBLR4F	45.7	2.51	344.3	0.00	0.00	0.00	CON	Yes
		Unit 7	USSBLR7F	68.6	2.59	405.4	23.60	15.86	15.81	CON	Yes
0990234	Palm Beach Co. Resource Recovery 1&2 PSD		PBCRRF	76.2	2.04	505.2	24.90	85.05	85.05	CON	Yes
0990019	Osceola Farms PSD Baseline ^a										
		Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-5.07	-5.07	EXP	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-16.32	-16.32	EXP	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-7.26	-7.26	EXP	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-13.61	-13.61	EXP	Yes
		Unit 2	OSBLR2	27.4	1.52	341.0	15.82	17.12	5.87	CON	Yes
		Unit 3	OSBLR3	27.4	1.91	342.0	16.86	30.74	6.39	CON	Yes
		Unit 4	OSBLR4	27.4	1.83	340.7	22.80	12.70	11.90	CON	Yes
		Unit 5a	OSBLR5A	27.4	1.52	340.7	18.60	6.33	5.96	CON	Yes

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
		Unit 5b	OSBLR5B	27.4	1.52	340.7	18.60	6.33	5.96	CON	Yes
		Unit 6	OSBLR6	27.4	1.88	341.0	18.19	33.39	2.08	CON	Yes
0990061	US Sugar-Bryant ^a										
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	62.40	62.40	CON	Yes
		Unit 1,2&3 PSD	USBRY123	19.8	1.64	342.0	36.40	160.68	160.68	CON	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-36.50	-36.50	EXP	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-73.00	-73.00	EXP	Yes
990021	Pratt & Whitney (United Technologies)										
		Heater	PRATARCH	15.2	0.91	810.9	143.73	13.99	13.99	CON	Yes
		Boiler BO-12, -1, -2, -14, -3	PRATBO12	4.6	0.76	533.2	6.92	0.012	0.012	CON	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	75.64	75.64	CON	Yes
0850001	FPL Martin										
		Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	12.90	12.90	CON	Yes
		Diesel Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	0.51	0.51	CON	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	470.40	470.40	CON	Yes
		Unit 8	MART8OIL	36.6	5.79	420.0	22.40	51.96	51.96	CON	Yes

Note: EXP = PSD expanding source
CON = PSD consuming source

^a Facilities or sources within facilities that operate only during the October 1 through April 30 crop season.

^b Sugar mill sources that operate all year.

^c Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	(lb/hr)	(g/s)		
0250348	Miami-Dade County RRF										
		Units 1&2	DCRRF12	76.2	3.66	405.4	15.86	13.24	1.67	CON	Yes
		Units 3&4	DCRRF34	76.2	3.66	405.4	15.86	13.24	1.67	CON	Yes
0130020	Tarmac										
		Kiln No. 1 Baseline	TARMK1B	61.0	2.44	465.0	12.84	-4.80	-0.60	EXP	Yes
		Kiln No. 2 Baseline	TARMK2B	61.0	2.44	465.0	12.84	-4.80	-0.60	EXP	Yes
		Kiln No. 3 Baseline	TARMK3B	61.0	4.57	472.0	10.78	0.00	0.00	EXP	Yes
		Kiln No. 2	TARMK2	61.0	2.44	422.0	9.10	14.40	1.81	CON	Yes
		Cooler No. 2	TARMC2	26.2	1.82	394.0	8.71	26.40	3.33	CON	Yes
		Kiln No. 3	TARMK3	61.0	4.57	450.0	11.04	42.50	5.36	CON	Yes
		Cooler No. 3	TARMC3	30.5	2.74	394.0	2.88	14.20	1.79	CON	Yes
		Clinker Handling System	TARMCH	48.7	0.30	298.0	32.36	1.76	0.22	CON	Yes
		Finish Mill Nos. 1, 2, 3, and 4	TARMF13	64.0	0.61	372.0	48.54	93.70	11.81	CON	Yes
		Coal Handling System	TARMCLH	35.7	0.30	298.0	232.97	3.90	0.49	CON	Yes
		Slag Dryer	TARMSD	9.1	0.70	505.0	26.99	4.80	0.60	CON	Yes
0112119	South Broward RRF PSD		SBCRRF	59.4	3.96	381.0	18.01	24.20	3.05	CON	Yes
0110037	FPL - Lauderdale										
		CTs 1-4 PSD	LAUDU45	45.7	5.49	438.7	14.60	14.70	1.85	CON	Yes
		4&5 PSD Baseline	FTLAU45B	46.0	4.27	422.0	14.63	-32.17	-4.05	EXP	Yes
0110120	North Broward RRF PSD		NBCRRF	58.5	3.96	381.0	18.01	22.83	2.88	CON	Yes
0112545	El Paso Broward										
		Combined Cycle CT CC-1	EPBRCT1	41.1	5.79	359.3	61.13	20.00	2.52	CON	Yes
		Simple Cycle SC-1	EPBRSC1	41.1	5.79	862.0	146.96	20.00	2.52	CON	Yes
		Simple Cycle SC-2	EPBRSC2	41.1	5.79	862.0	146.96	20.00	2.52	CON	Yes
		Simple Cycle SC-3	EPBRSC3	41.1	5.79	862.0	146.96	20.00	2.52	CON	Yes
0710019	Lee County RRF PSD		LEECORRF	83.8	1.88	388.5	19.81	5.08	0.64	CON	Yes
0990005	Okeelanta *										
		Boiler 4 PSD Baseline	OKBLR4B	22.9	2.29	333.0	7.36	-54.60	-6.88	EXP	Yes
		Boiler 5 PSD Baseline	OKBLR5B	22.9	2.29	333.0	12.07	-54.60	-6.88	EXP	Yes

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	(lb/hr)	(g/s)		
		Boiler 6 PSD Baseline	OKBLR6B	22.9	2.29	334.0	8.74	-78.00	-9.83	EXP	Yes
		Boiler 10 PSD Baseline	OKBLR10B	22.9	2.29	334.0	10.35	-57.00	-7.18	EXP	Yes
		Boiler 11 PSD Baseline	OKBLR11B	22.9	2.29	342.0	9.89	-55.80	-7.03	EXP	Yes
		Boiler 16 PSD	OKBLR16	22.9	1.52	483.0	22.86	6.10	0.77	CON	Yes
0990332	New Hope Power Partnership (Okeelanta)										
		Okeelanta Power Blrs 1,2,3 ^b	OKCOGENF	60.7	3.05	450.9	19.39	38.6	4.9	CON	Yes
710002	FPL - Fort Myers										
		Unit 1 PSD	FMU1	91.8	2.90	422.0	29.90	-169.05	-21.30	EXP	Yes
		Unit 2 PSD	FMU2	121.2	5.52	408.0	19.20	-384.92	-48.50	EXP	Yes
		HRSs 1 - 6	FMYHR1_6	38.1	5.79	377.6	14.2	60.00	7.56	CON	Yes
0990016	Atlantic Sugar Association ^a										
		Unit 1	ASA1	27.4	1.83	346.0	17.97	83.97	10.58	CON	Yes
		Unit 2	ASA2	27.4	1.83	350.0	23.36	83.97	10.58	CON	Yes
		Unit 3	ASA3	27.4	1.83	350.0	21.56	78.02	9.83	CON	Yes
		Unit 4	ASA4	27.4	1.83	344.0	25.16	79.76	10.05	CON	Yes
		Unit 5 PSD	ASA5	27.4	1.68	339.0	19.24	35.71	4.50	CON	Yes
		Unit 1 PSD Baseline	ASA1B	18.9	1.92	506.0	12.70	-116.98	-14.74	EXP	Yes
		Unit 2 PSD Baseline	ASA2B	18.9	1.92	511.0	10.90	-141.98	-17.89	EXP	Yes
		Unit 3 PSD Baseline	ASA3B	21.9	1.83	522.0	17.50	-73.97	-9.32	EXP	Yes
		Unit 4 PSD Baseline	ASA4B	18.3	1.83	344.0	15.00	-73.41	-9.25	EXP	Yes
0510015	Southern Gardens Citrus - PSD										
		Peel Dryer	SGARDDRY	38.1	1.73	316.0	7.45	5.60	0.71	CON	Yes
		Boilers 1-3	SGARDBLR	16.8	1.22	478.0	14.22	1.44	0.18	CON	Yes
0990568	Lake Worth Utilities										
		Unit 5, S-5	LAKWTHUS	22.9	3.05	481.0	27.80	41.90	5.28	CON	Yes
990026	Sugar Cane Growers ^a										
		Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	51.51	6.49	CON	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	102.78	12.95	CON	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	98.81	12.45	CON	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	98.81	12.45	CON	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	68.02	8.57	CON	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-150.32	-18.94	EXP	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-45.24	-5.70	EXP	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-86.51	-10.90	EXP	Yes

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	(lb/hr)	(g/s)		
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-72.22	-9.10	EXP	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-19.84	-2.50	EXP	Yes
0990594	El Paso Belle Glade										
		Combined Cycle CT CC-1	EPBGLCT	41.1	5.79	359.3	61.13	20.00	2.52	CON	Yes
		Simple Cycle SC-1	EPBGSC1	41.1	5.79	862.0	146.96	18.30	2.31	CON	Yes
		Simple Cycle SC-2	EPBGSC2	41.1	5.79	862.0	146.96	18.30	2.31	CON	Yes
		Simple Cycle SC-3	EPBGSC3	41.1	5.79	862.0	146.96	18.30	2.31	CON	Yes
510003	US Sugar - Clewiston ^b										
		Unit 8	USSBLR8	60.7	3.96	439.0	15.30	24.30	3.06	CON	Yes
		<u>PSD Baseline (On-crop season only)</u>									
		Unit 1 PSD Baseline	USSBRL1B	23.1	1.86	344.0	30.20	-59.37	-7.48	EXP	Yes
		Unit 2 PSD Baseline	USSBLR2B	23.1	1.86	343.0	35.70	-55.87	-7.04	EXP	Yes
		Unit 3 PSD Baseline	USSBLR3B	27.4	2.29	342.0	14.70	-36.27	-4.57	EXP	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-13.41	-1.69	EXP	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-6.51	-0.82	EXP	Yes
		Units 5&6 PSD Baseline	USBLR56B	23.1	1.86	494.0	44.30	-420.00	-52.92	EXP	Yes
		<u>On-crop season future</u>									
		Unit 1	USSBLR1N	65.0	2.44	347.0	19.20	115.24	14.52	CON	Yes
		Unit 2	USSBLR2N	65.0	2.44	338.7	17.32	115.24	14.52	CON	Yes
		Unit 4	USSBLR4N	45.7	2.51	344.3	24.03	83.73	10.55	CON	Yes
		Unit 7	USSBLR7N	68.6	2.59	405.4	23.60	22.14	2.79	CON	Yes
		<u>Off-crop season future</u>									
		Unit 1	USSBLR1F	65.0	2.44	347.0	17.70	106.20	13.38	CON	Yes
		Unit 2	USSBLR2F	65.0	2.44	338.7	16.19	97.20	12.25	CON	Yes
		Unit 4	USSBLR4F	45.7	2.51	344.3	0.00	0.00	0.00	CON	Yes
		Unit 7	USSBLR7F	68.6	2.59	405.4	23.60	22.14	2.79	CON	Yes
0990234	Palm Beach Co. Resource Recovery 1&2 PSD		PBCRRF	76.2	2.04	505.2	24.90	23.38	2.95	CON	Yes
0990019	Osceola Farms PSD ^a										
		Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-116.98	-14.74	EXP	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-141.98	-17.89	EXP	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-73.97	-9.32	EXP	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-73.41	-9.25	EXP	Yes
		Unit 2 PSD	OSBLR2	27.4	1.52	341.0	15.82	56.03	7.06	CON	Yes

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	(lb/hr)	(g/s)		
		Unit 3 PSD	OSBLR3	27.4	1.91	342.0	16.86	58.41	7.36	CON	Yes
		Unit 4 PSD	OSBLR4	27.4	1.83	340.7	22.80	44.40	5.59	CON	Yes
		Unit 5a	OSBLR5A	27.4	1.52	340.7	18.60	22.20	2.80	CON	Yes
		Unit 5b	OSBLR5B	27.4	1.52	340.7	18.60	23.20	2.92	CON	Yes
		Unit 6 PSD	OSBLR6	27.4	1.88	341.0	18.19	56.90	7.17	CON	Yes
990061	US Sugar-Bryant ^a										
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	99.92	12.59	CON	Yes
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	346.51	43.66	CON	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-653.97	-82.40	EXP	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-95.56	-12.04	EXP	Yes
990021	Pratt & Whitney (United Technologies)										
	Boiler BO-12, -1, -2, -14, -3		PRATBO12	4.6	0.76	533.2	6.92	0.29	0.04	CON	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	47.42	5.97	CON	Yes
850001	FPL -Martin										
	Aux Blr PSD		MARTAUx	18.3	1.10	535.4	15.24	0.10	0.01	CON	Yes
	Diesel Gens PSD		MARTGEN	7.6	0.30	785.9	39.62	1.72	0.22	CON	Yes
	Units 3&4 PSD		MART34	64.9	6.10	410.9	18.90	242.40	30.54	CON	Yes
	Unit 8		MART8OIL	36.6	5.79	420.0	22.40	151.20	19.05	CON	Yes

Note: EXP = PSD expanding source
CON = PSD consuming source

^a Facilities or sources within facilities that operate only during the October 1 through April 30 crop season.

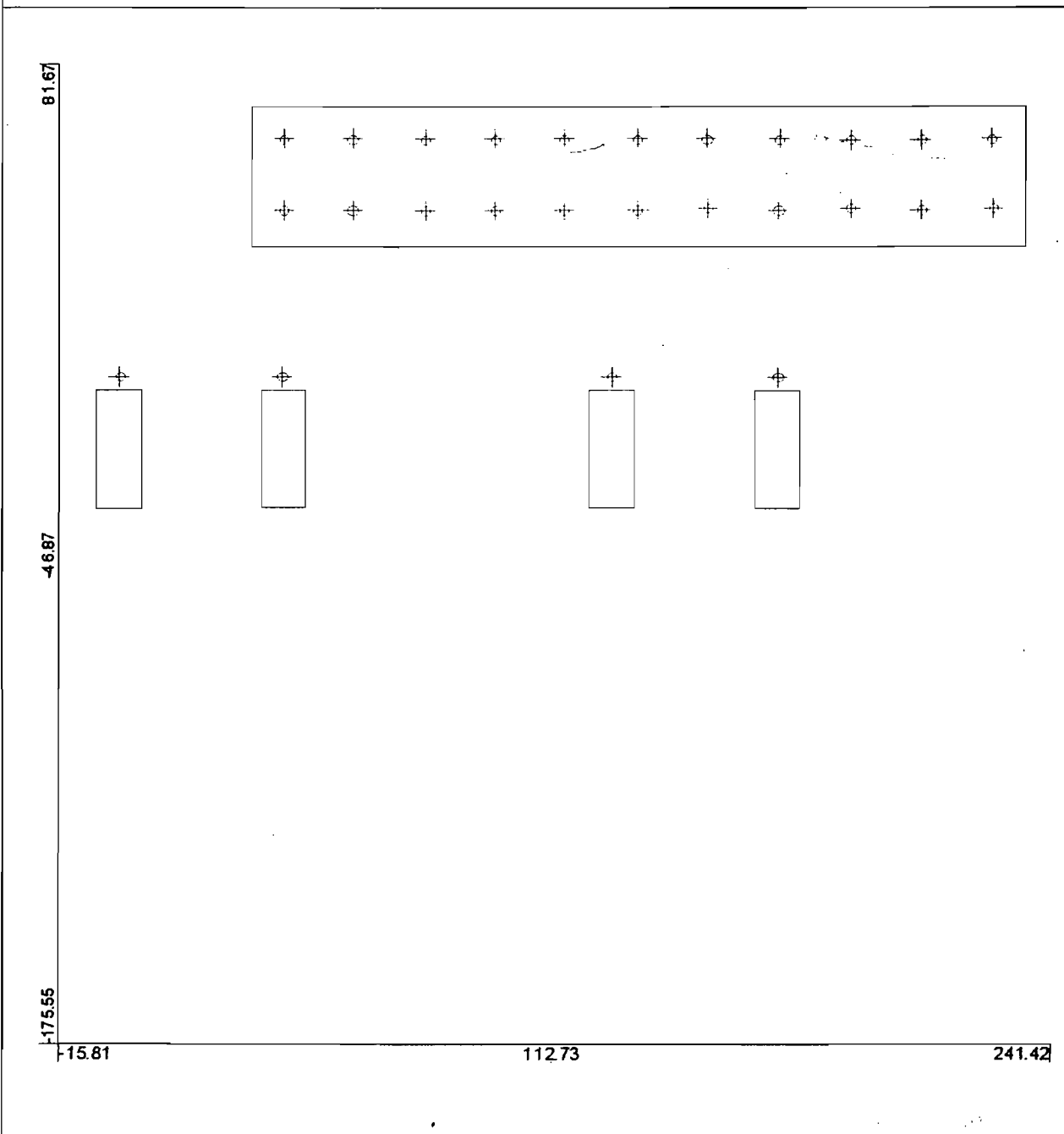
^b Sugar mill sources that operate all year.

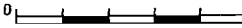
^c Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.

APPENDIX E

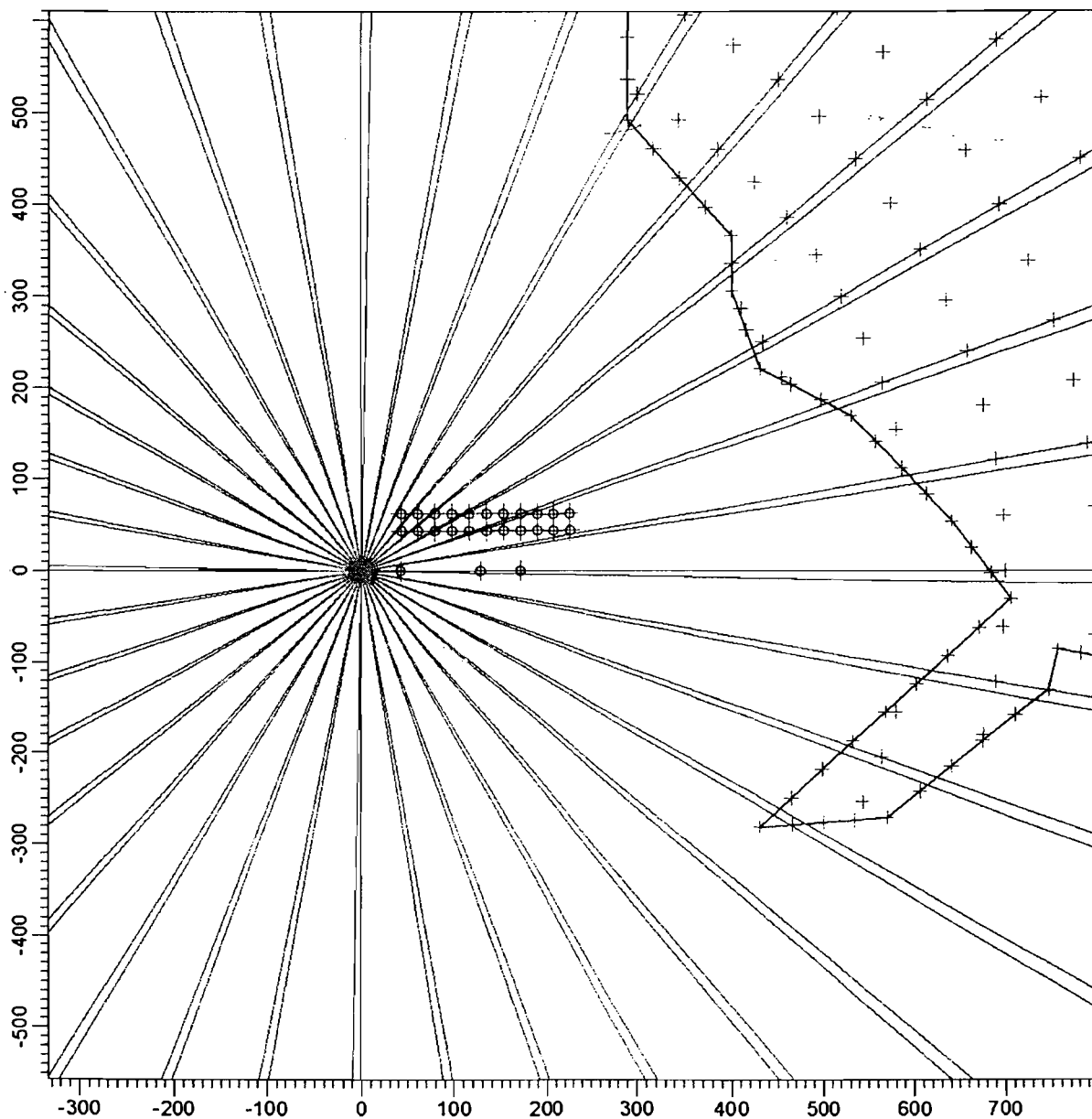
RECEPTOR LOCATION FIGURES AND BUILDING PROFILE INPUT PROGRAM (BPIP) FILES

PROJECT TITLE
FPL Turkey Point Combined Cycle CT Project



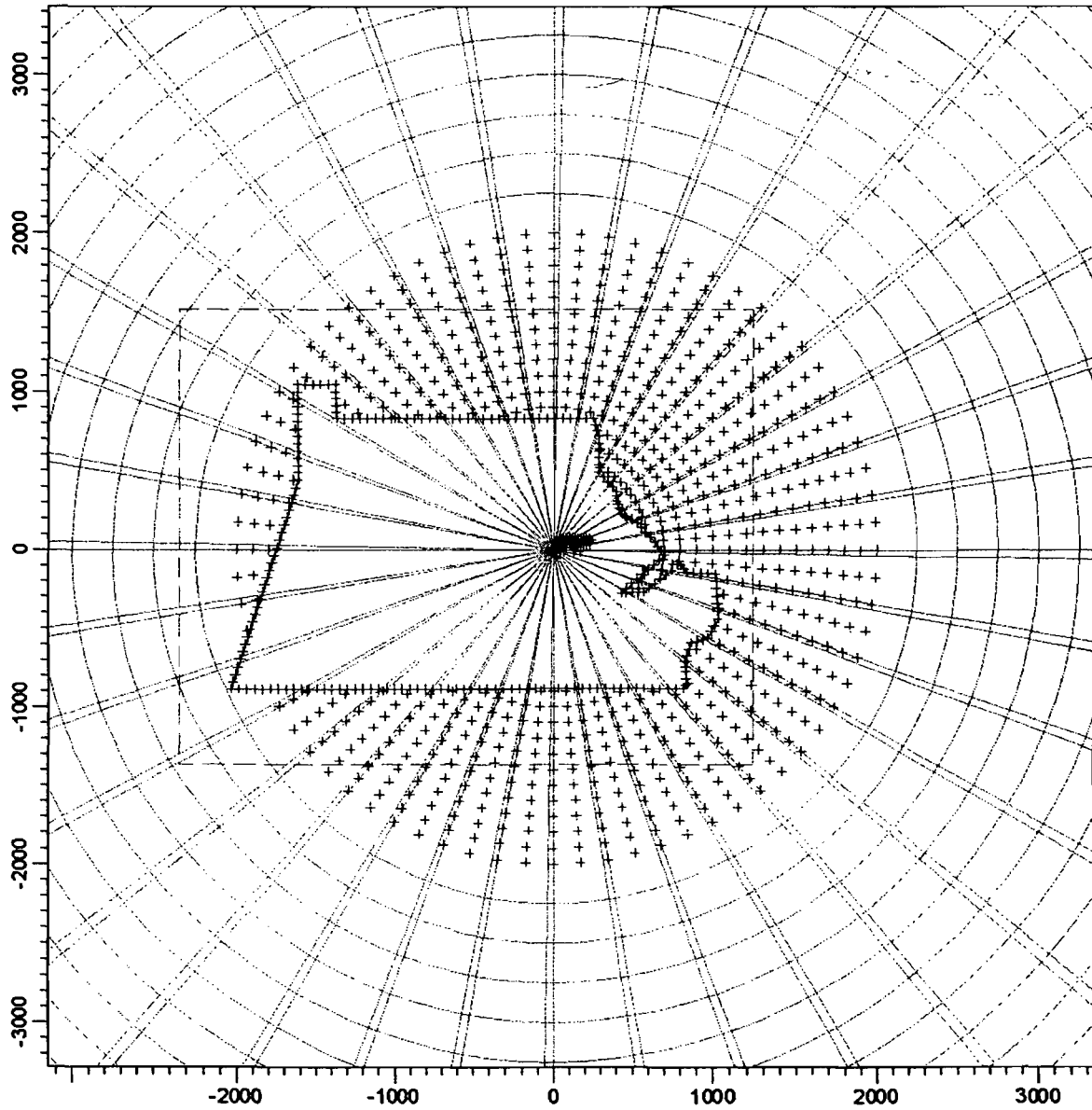
COMMENTS	BUILDINGS 5	COMPANY NAME	
	SOURCES 26	MODELER:	SCALE 0  0.05 km
		DATE 11/4/03	PROJECT NO:

PROJECT TITLE:
FPL Turkey Point
Unit 5 Sources



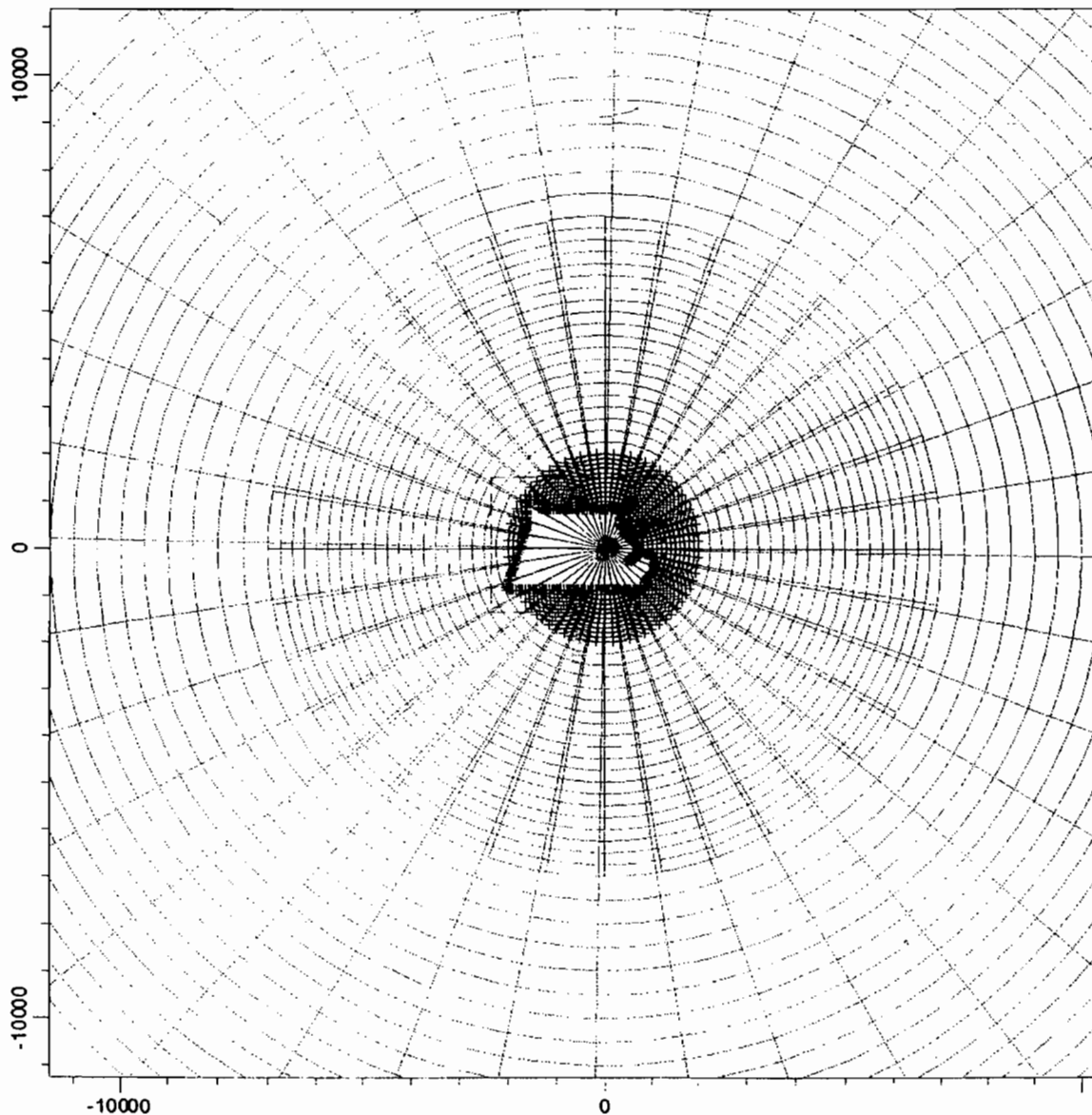
COMMENTS:	SOURCES :	COMPANY NAME:	
	26		
	RECEPTORS :	MODELER:	SCALE:
	2220		0  0.2 km
		DATE:	PROJECT NO.:
		11/6/2003	

PROJECT TITLE
TurkeyPoint
Fence-Line and Near-Field Receptors



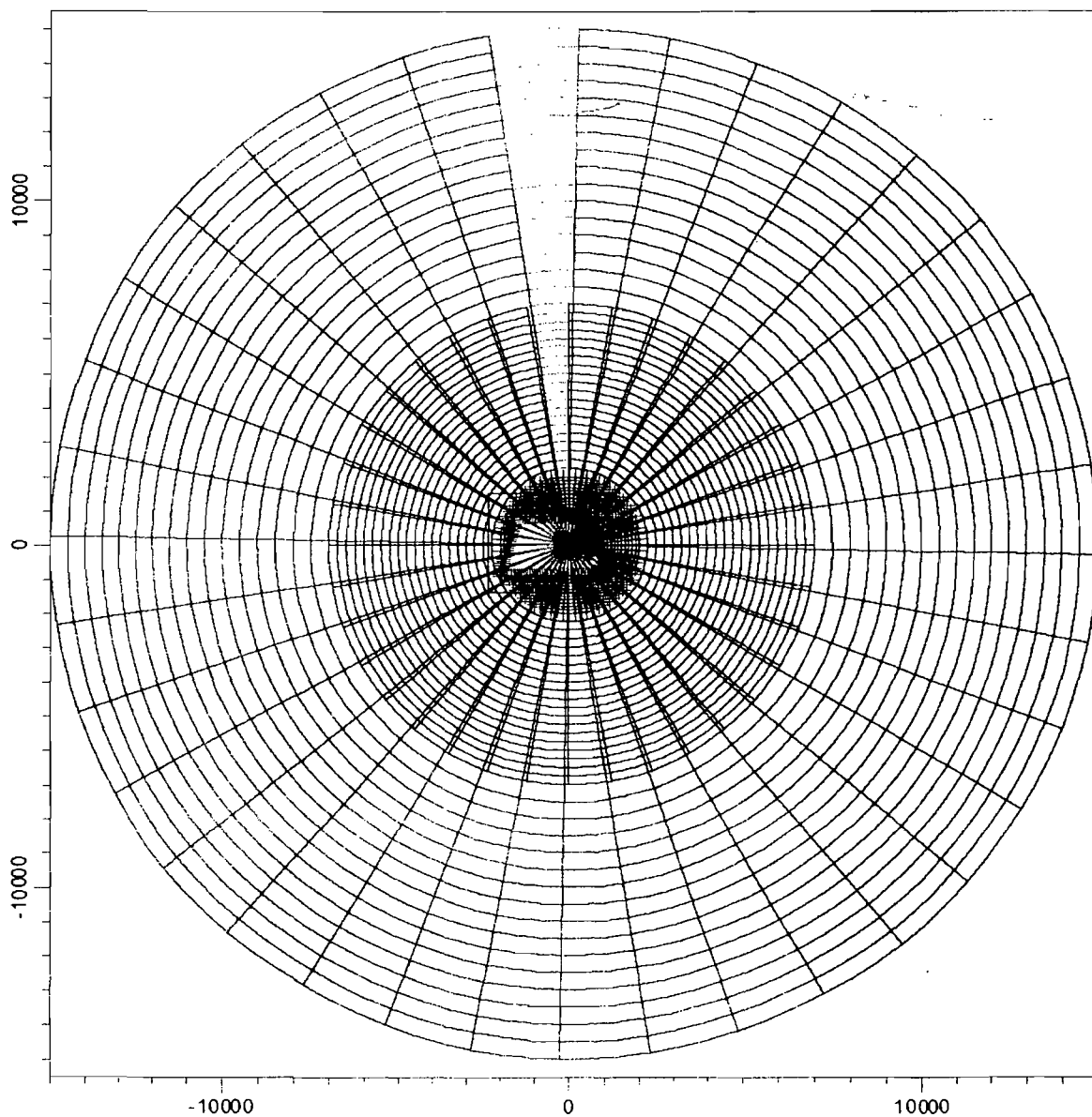
COMMENTS	SOURCES:	COMPANY NAME	
	26		
	RECEPTORS:	MODELER:	SCALE
	2220		0 1 km
		DATE	PROJECT NO:
		11/5/03	

PROJECT TITLE
FPL Turkey Point
Mid-Field Receptors



COMMENTS	SOURCES	COMPANY NAME	
	26		
	RECEPTORS	MODELEP	SCALE
	2220		0 4 km
		DATE	PROJECT NO:
		11/5/03	

PROJECT TITLE
FPL Turkey Point
Far-Field Receptors



COMMENTS	SOURCES	COMPANY NAME	
	26		
	RECEPTORS	MODELER	SCALE
	2720		0 5 km
		DATE	PROJECT NO.
		11/5/03	

Appendix E BPIP Input File

'J:\PROJECTS\FPL\turkey\bpip\ctproj.bpv'

'ST'

'Meters' 1.00000000

'UTMN' 0.0000

5

'HRSG1' 1 0.000

4 26.500
-5.890 -3.420
5.710 -3.420
5.710 -34.430
-5.890 -34.430

'HRSG2' 1 0.000

4 26.500
36.860 -3.420
48.460 -3.420
48.460 -34.160
36.860 -34.160

'HRSG3' 1 0.000

4 26.500
122.090 -3.420
133.690 -3.420
133.690 -34.160
122.090 -34.160

'HRSG4' 1 0.000

4 26.500
164.850 -3.420
176.450 -3.420
176.450 -34.160
164.850 -34.160

'COOL' 1 0.000

4 15.500
34.350 70.920
234.850 70.920
234.850 34.170
34.350 34.170

26

'HRSGA'	0.000	39.930	0.000	0.000
'HRSGB'	0.000	39.930	42.450	0.000
'HRSGC'	0.000	39.930	127.960	0.000
'HRSGD'	0.000	39.930	170.720	0.000
'CELL01'	0.000	19.800	42.870	62.390
'CELL02'	0.000	19.800	61.040	62.390
'CELL03'	0.000	19.800	79.620	62.390
'CELL04'	0.000	19.800	97.780	62.390
'CELL05'	0.000	19.800	115.950	62.390
'CELL06'	0.000	19.800	134.390	62.390
'CELL07'	0.000	19.800	152.270	62.390
'CELL08'	0.000	19.800	171.140	62.390
'CELL09'	0.000	19.800	189.300	61.970
'CELL10'	0.000	19.800	207.050	61.970
'CELL11'	0.000	19.800	225.630	62.390
'CELL12'	0.000	19.800	42.870	43.810
'CELL13'	0.000	19.800	61.040	43.810
'CELL14'	0.000	19.800	79.620	43.810
'CELL15'	0.000	19.800	97.780	43.810
'CELL16'	0.000	19.800	115.950	43.810
'CELL17'	0.000	19.800	134.390	43.810
'CELL18'	0.000	19.800	152.550	44.230
'CELL19'	0.000	19.800	170.720	43.810
'CELL20'	0.000	19.800	189.300	44.230
'CELL21'	0.000	19.800	207.050	43.810
'CELL22'	0.000	19.800	226.050	44.230

Appendix E BPIP Output File
BPIP (Dated: 95086)

DATE : 11/ 4/ 3
TIME : 15: 6:54
J:\PROJECTS\FPL\turkey\bpip\ctproj.bpv

=====

BPIP PROCESSING INFORMATION:

=====

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using
a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local
X-Y coordinate system as opposed to a UTM coordinate system.
True North is in the positive Y direction.

Plant north is set to 0.00 degrees with respect to True North.

J:\PROJECTS\FPL\turkey\bpip\ctproj.bpv

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
HRSGA	39.93	0.00	66.25	66.25
HRSGB	39.93	0.00	66.25	66.25
HRSGC	39.93	0.00	66.25	66.25
HRSGD	39.93	0.00	66.25	66.25
CELL01	19.80	0.00	66.25	66.25
CELL02	19.80	0.00	66.25	66.25
CELL03	19.80	0.00	66.25	66.25
CELL04	19.80	0.00	66.25	66.25
CELL05	19.80	0.00	66.25	66.25
CELL06	19.80	0.00	66.25	66.25
CELL07	19.80	0.00	66.25	66.25
CELL08	19.80	0.00	66.25	66.25
CELL09	19.80	0.00	66.25	66.25
CELL10	19.80	0.00	66.25	66.25
CELL11	19.80	0.00	66.25	66.25
CELL12	19.80	0.00	66.25	66.25
CELL13	19.80	0.00	66.25	66.25
CELL14	19.80	0.00	66.25	66.25
CELL15	19.80	0.00	66.25	66.25
CELL16	19.80	0.00	66.25	66.25
CELL17	19.80	0.00	66.25	66.25
CELL18	19.80	0.00	66.25	66.25
CELL19	19.80	0.00	66.25	66.25
CELL20	19.80	0.00	66.25	66.25
CELL21	19.80	0.00	66.25	66.25
CELL22	19.80	0.00	66.25	66.25

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP
Technical Support Document. Determinant 3 may be investigated for
additional stack height credit. Final values result after

Appendix E BPIP Output File

Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 11/ 4/ 3

TIME : 15: 6:54

J:\PROJECTS\FPL\turkey\bpip\ctproj.bpv

BPIP output is in meters

SO BUILDHGT	HRSGA	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGA	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGA	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGA	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGA	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGA	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDWID	HRSGA	16.81	21.51	25.55	28.82	31.21	32.66
SO BUILDWID	HRSGA	33.11	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRSGA	31.00	28.65	25.55	21.51	16.81	11.60
SO BUILDWID	HRSGA	16.81	21.51	25.55	28.82	31.21	32.66
SO BUILDWID	HRSGA	33.11	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRSGA	31.00	28.65	25.55	21.51	16.81	11.60

SO BUILDHGT	HRSGB	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGB	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGB	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGB	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGB	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGB	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDWID	HRSGB	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	HRSGB	32.85	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRSGB	31.00	28.65	25.42	21.41	16.76	11.60
SO BUILDWID	HRSGB	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	HRSGB	32.85	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRSGB	31.00	28.65	25.42	21.41	16.76	11.60

SO BUILDHGT	HRSGC	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGC	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGC	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGC	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGC	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRSGC	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDWID	HRSGC	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	HRSGC	32.85	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRSGC	31.00	28.65	25.42	21.41	16.76	11.60
SO BUILDWID	HRSGC	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	HRSGC	32.85	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRSGC	31.00	28.65	25.42	21.41	16.76	11.60

Appendix E BPIP Output File

SO BUILDHGT	HRS	GD	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRS	GD	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRS	GD	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRS	GD	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRS	GD	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	HRS	GD	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDWID	HRS	GD	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	HRS	GD	32.85	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRS	GD	31.00	28.65	25.42	21.41	16.76	11.60
SO BUILDWID	HRS	GD	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	HRS	GD	32.85	32.29	30.74	32.29	32.85	32.42
SO BUILDWID	HRS	GD	31.00	28.65	25.42	21.41	16.76	11.60

SO BUILDHGT	CELL	01	26.50	26.50	26.50	26.50	15.50	15.50
SO BUILDHGT	CELL	01	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	01	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	01	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	01	15.50	15.50	15.50	15.50	15.50	26.50
SO BUILDHGT	CELL	01	26.50	26.50	15.50	15.50	26.50	26.50
SO BUILDWID	CELL	01	16.76	21.51	25.55	28.82	157.03	132.08
SO BUILDWID	CELL	01	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL	01	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID	CELL	01	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID	CELL	01	103.11	71.01	36.75	71.01	103.11	32.42
SO BUILDWID	CELL	01	31.00	28.65	192.01	200.98	16.76	11.60

SO BUILDHGT	CELL	02	26.50	26.50	26.50	26.50	26.50	15.50
SO BUILDHGT	CELL	02	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	02	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	02	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	02	15.50	15.50	15.50	15.50	15.50	26.50
SO BUILDHGT	CELL	02	26.50	26.50	26.50	15.50	15.50	15.50
SO BUILDWID	CELL	02	16.76	21.41	25.55	28.82	31.21	132.08
SO BUILDWID	CELL	02	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL	02	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID	CELL	02	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID	CELL	02	103.11	71.01	36.75	71.01	103.11	32.42
SO BUILDWID	CELL	02	31.00	28.65	25.42	200.98	203.84	200.50

SO BUILDHGT	CELL	03	15.50	26.50	26.50	26.50	26.50	15.50
SO BUILDHGT	CELL	03	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	03	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	03	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	03	15.50	15.50	15.50	15.50	15.50	26.50
SO BUILDHGT	CELL	03	26.50	26.50	26.50	26.50	15.50	15.50
SO BUILDWID	CELL	03	203.84	21.41	25.42	28.65	31.21	132.08
SO BUILDWID	CELL	03	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL	03	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID	CELL	03	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID	CELL	03	103.11	71.01	36.75	71.01	103.11	32.42
SO BUILDWID	CELL	03	31.00	28.65	25.42	21.41	203.84	200.50

SO BUILDHGT	CELL	04	15.50	15.50	26.50	26.50	26.50	26.50
SO BUILDHGT	CELL	04	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	04	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	04	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL	04	15.50	15.50	15.50	15.50	15.50	15.50

Appendix E BPIP Output File

SO BUILDHGT CELL04	26.50	26.50	26.50	26.50	26.50	15.50
SO BUILDWID CELL04	203.84	200.98	25.42	28.65	31.00	32.66
SO BUILDWID CELL04	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL04	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL04	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL04	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL04	31.00	28.65	25.42	21.41	16.76	200.50

SO BUILDHGT CELL05	15.50	15.50	26.50	26.50	26.50	26.50
SO BUILDHGT CELL05	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL05	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL05	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL05	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL05	26.50	26.50	26.50	26.50	26.50	15.50
SO BUILDWID CELL05	203.84	200.98	25.42	28.65	31.00	32.66
SO BUILDWID CELL05	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL05	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL05	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL05	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL05	31.00	28.65	25.42	21.41	16.76	200.50

SO BUILDHGT CELL06	26.50	15.50	15.50	26.50	26.50	26.50
SO BUILDHGT CELL06	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL06	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL06	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL06	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL06	15.50	26.50	26.50	26.50	15.50	26.50
SO BUILDWID CELL06	16.76	200.98	192.01	28.65	31.00	32.42
SO BUILDWID CELL06	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL06	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL06	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL06	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL06	157.03	28.65	25.42	21.41	203.84	11.60

SO BUILDHGT CELL07	26.50	26.50	26.50	15.50	26.50	26.50
SO BUILDHGT CELL07	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL07	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL07	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL07	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL07	15.50	15.50	26.50	26.50	26.50	15.50
SO BUILDWID CELL07	16.76	21.41	25.42	177.21	31.00	32.42
SO BUILDWID CELL07	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL07	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL07	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL07	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL07	157.03	177.21	25.42	21.41	16.76	200.50

SO BUILDHGT CELL08	26.50	26.50	26.50	26.50	15.50	15.50
SO BUILDHGT CELL08	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL08	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL08	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL08	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL08	15.50	15.50	15.50	15.50	26.50	26.50
SO BUILDWID CELL08	16.76	21.41	25.42	28.65	157.03	132.08
SO BUILDWID CELL08	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL08	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL08	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL08	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL08	157.03	177.21	192.01	200.98	16.76	11.60

Appendix E BPIP Output File

SO BUILDHGT CELL09	26.50	26.50	26.50	26.50	26.50	15.50
SO BUILDHGT CELL09	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL09	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL09	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL09	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL09	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDWID CELL09	16.76	21.41	25.42	28.65	31.00	132.08
SO BUILDWID CELL09	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL09	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL09	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL09	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL09	157.03	177.21	192.01	200.98	203.84	200.50

SO BUILDHGT CELL10	15.50	26.50	26.50	26.50	26.50	15.50
SO BUILDHGT CELL10	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL10	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL10	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL10	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL10	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDWID CELL10	203.84	21.41	25.42	28.65	31.00	132.08
SO BUILDWID CELL10	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL10	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL10	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL10	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL10	157.03	177.21	192.01	200.98	203.84	200.50

SO BUILDHGT CELL11	15.50	15.50	26.50	26.50	26.50	26.50
SO BUILDHGT CELL11	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL11	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL11	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL11	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL11	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDWID CELL11	203.84	200.98	25.42	28.65	31.00	32.42
SO BUILDWID CELL11	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL11	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL11	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL11	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL11	157.03	177.21	192.01	200.98	203.84	200.50

SO BUILDHGT CELL12	26.50	26.50	26.50	26.50	26.50	15.50
SO BUILDHGT CELL12	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL12	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL12	15.50	26.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL12	15.50	15.50	15.50	15.50	26.50	26.50
SO BUILDHGT CELL12	26.50	26.50	15.50	15.50	26.50	26.50
SO BUILDWID CELL12	16.76	21.51	25.55	28.82	31.21	132.08
SO BUILDWID CELL12	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL12	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL12	203.84	21.41	192.01	177.21	157.03	132.08
SO BUILDWID CELL12	103.11	71.01	36.75	71.01	32.85	32.42
SO BUILDWID CELL12	31.00	28.65	192.01	200.98	16.76	11.60

SO BUILDHGT CELL13	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT CELL13	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL13	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL13	15.50	15.50	26.50	26.50	15.50	15.50
SO BUILDHGT CELL13	15.50	15.50	15.50	15.50	26.50	26.50

Appendix E BPIP Output File

SO BUILDHGT CELL13	26.50	26.50	15.50	15.50	15.50	15.50
SO BUILDWID CELL13	16.76	21.41	25.55	28.65	31.21	32.66
SO BUILDWID CELL13	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL13	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL13	203.84	200.98	25.42	28.65	157.03	132.08
SO BUILDWID CELL13	103.11	71.01	36.75	71.01	32.85	32.42
SO BUILDWID CELL13	31.00	28.65	192.01	200.98	203.84	200.50

SO BUILDHGT CELL14	15.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT CELL14	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL14	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL14	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL14	15.50	15.50	15.50	15.50	15.50	26.50
SO BUILDHGT CELL14	26.50	26.50	26.50	15.50	15.50	15.50
SO BUILDWID CELL14	203.84	21.41	25.42	28.65	31.00	32.66
SO BUILDWID CELL14	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL14	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL14	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL14	103.11	71.01	36.75	71.01	32.85	32.42
SO BUILDWID CELL14	31.00	28.65	25.42	200.98	203.84	200.50

SO BUILDHGT CELL15	15.50	15.50	26.50	26.50	26.50	26.50
SO BUILDHGT CELL15	26.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL15	26.50	26.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL15	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL15	15.50	15.50	15.50	15.50	15.50	26.50
SO BUILDHGT CELL15	26.50	26.50	26.50	26.50	15.50	15.50
SO BUILDWID CELL15	203.84	200.98	25.42	28.65	31.00	32.42
SO BUILDWID CELL15	33.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL15	31.00	28.65	192.01	200.98	203.84	200.50
SO BUILDWID CELL15	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL15	103.11	71.01	36.75	71.01	103.11	32.42
SO BUILDWID CELL15	31.00	28.65	25.42	21.41	203.84	200.50

SO BUILDHGT CELL16	15.50	15.50	15.50	26.50	26.50	26.50
SO BUILDHGT CELL16	26.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL16	15.50	15.50	26.50	15.50	15.50	15.50
SO BUILDHGT CELL16	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL16	15.50	15.50	15.50	15.50	15.50	26.50
SO BUILDHGT CELL16	26.50	26.50	26.50	26.50	26.50	15.50
SO BUILDWID CELL16	203.84	200.98	192.01	28.65	31.00	32.42
SO BUILDWID CELL16	33.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL16	157.03	177.21	25.42	200.98	203.84	200.50
SO BUILDWID CELL16	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL16	103.11	71.01	36.75	71.01	103.11	32.42
SO BUILDWID CELL16	31.00	28.65	25.42	21.41	16.76	200.50

SO BUILDHGT CELL17	26.50	26.50	15.50	15.50	26.50	26.50
SO BUILDHGT CELL17	26.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL17	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL17	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL17	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT CELL17	26.50	26.50	26.50	26.50	15.50	26.50
SO BUILDWID CELL17	16.76	21.41	192.01	177.21	31.00	32.42
SO BUILDWID CELL17	32.85	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL17	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL17	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL17	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL17	31.00	28.65	25.42	21.41	203.84	11.60

Appendix E BPIP Output File

SO BUILDHGT	CELL18	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	CELL18	26.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL18	15.50	26.50	26.50	15.50	15.50	15.50
SO BUILDHGT	CELL18	15.50	15.50	26.50	26.50	15.50	15.50
SO BUILDHGT	CELL18	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL18	15.50	26.50	26.50	26.50	26.50	15.50
SO BUILDWID	CELL18	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	CELL18	32.85	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL18	157.03	28.65	25.42	200.98	203.84	200.50
SO BUILDWID	CELL18	203.84	200.98	25.42	28.65	157.03	132.08
SO BUILDWID	CELL18	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL18	157.03	28.65	25.42	21.41	16.76	200.50

SO BUILDHGT	CELL19	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	CELL19	26.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL19	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL19	15.50	26.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL19	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL19	15.50	15.50	15.50	15.50	26.50	26.50
SO BUILDWID	CELL19	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	CELL19	32.85	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL19	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID	CELL19	203.84	21.41	192.01	177.21	157.03	132.08
SO BUILDWID	CELL19	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL19	157.03	177.21	192.01	200.98	16.76	11.60

SO BUILDHGT	CELL20	26.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL20	15.50	15.50	26.50	26.50	15.50	15.50
SO BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDWID	CELL20	16.76	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	CELL20	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL20	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID	CELL20	203.84	200.98	25.42	28.65	157.03	132.08
SO BUILDWID	CELL20	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL20	157.03	177.21	192.01	200.98	203.84	200.50

SO BUILDHGT	CELL21	15.50	26.50	26.50	26.50	26.50	26.50
SO BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDWID	CELL21	203.84	21.41	25.42	28.65	31.00	32.42
SO BUILDWID	CELL21	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL21	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID	CELL21	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID	CELL21	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID	CELL21	157.03	177.21	192.01	200.98	203.84	200.50

SO BUILDHGT	CELL22	15.50	15.50	26.50	26.50	26.50	26.50
SO BUILDHGT	CELL22	26.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50

Appendix E BPIP Output File

SO BUILDHGT CELL22	15.50	15.50	15.50	15.50	15.50	15.50
SO BUILDWID CELL22	203.84	200.98	25.42	28.65	31.00	32.42
SO BUILDWID CELL22	32.85	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL22	157.03	177.21	192.01	200.98	203.84	200.50
SO BUILDWID CELL22	203.84	200.98	192.01	177.21	157.03	132.08
SO BUILDWID CELL22	103.11	71.01	36.75	71.01	103.11	132.08
SO BUILDWID CELL22	157.03	177.21	192.01	200.98	203.84	200.50

APPENDIX F

MODEL SUMMARY AND INPUT FILES

Table F-1. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature													Averaging Time	Maximum Predicted Concentrations (ug/m ³) by Operating Load and Air Inlet Temperature ^a																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																	
	Power Aug.				Higher Power Mode				Baseload ^b				75% Load				50% Load				Power Aug.				Higher Power Mode				Baseload				75% Load				50% Load																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																											
	80°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F		35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																

^a Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service stations at Miami and Palm Beach International Airports, respectively.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

^b Duct firing included for power augmentation and 100 % load operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of

550 mmBtu/hr (HHV).

Table F-2. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation
PSD Class I Area of the Everglades National Park

Pollutants	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature												Averaging Time	Maximum Predicted Concentrations (µg/m³) by Operating Load and Air Inlet Temperature ^a													
	Power Avg.				Higher Power Mode				Baseline ^b					Power Avg.				Higher Power Mode				Baseline					
	35°F	59°F	95°F	95°F	35°F	59°F	95°F	95°F	35°F	59°F	95°F	95°F		35°F	59°F	95°F	95°F	35°F	59°F	95°F	95°F	35°F	59°F	95°F	95°F		
Natural Gas Genere (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.059	0.053	0.054	0.055	0.056	0.057	0.059	0.062	0.062	0.063	0.069	0.069	0.069	
													24-Hour	0.595	0.550	0.558	0.568	0.574	0.582	0.593	0.618	0.619	0.628	0.722	0.723	0.723	
													8-Hour	1.247	1.094	1.109	1.131	1.149	1.184	1.236	1.442	1.449	1.494	1.747	1.749	1.750	
													3-Hour	2.783	2.346	2.390	2.456	2.521	2.615	2.753	3.082	3.099	3.223	3.964	3.973	3.974	
													1-Hour	5.268	4.513	4.622	4.788	4.910	5.040	5.225	5.865	5.883	5.938	6.613	6.614	6.601	
SO ₂	12.5	10.6	10.3	9.6	13.3	12.8	11.9	8.3	7.9	7.3	6.6	6.4	5.9	Annual	0.00929	0.00708	0.00701	0.00668	0.00932	0.00922	0.00878	0.00640	0.00618	0.00579	0.00572	0.00554	0.00511
													24-Hour	0.0940	0.0734	0.0723	0.0688	0.0960	0.0940	0.0888	0.0642	0.0620	0.0576	0.0600	0.0581	0.0535	
													8-Hour	0.1970	0.1458	0.1438	0.1370	0.1922	0.1915	0.1832	0.1500	0.1451	0.1372	0.1452	0.1407	0.1296	
													3-Hour	0.440	0.313	0.310	0.297	0.422	0.423	0.413	0.320	0.310	0.296	0.330	0.320	0.294	
													1-Hour	0.812	0.602	0.599	0.580	0.821	0.815	0.783	0.589	0.569	0.536	0.549	0.532	0.489	
PM ₁₀	14.3	11.1	11.1	10.9	14.4	14.3	14.2	10.7	10.6	10.5	10.3	10.3	10.2	Annual	0.0106	0.0075	0.0076	0.0076	0.0101	0.0103	0.0104	0.0081	0.0082	0.0083	0.0090	0.0089	0.0088
													24-Hour	0.107	0.077	0.078	0.078	0.104	0.105	0.106	0.083	0.083	0.083	0.094	0.094	0.093	
													8-Hour	0.224	0.154	0.155	0.156	0.209	0.214	0.220	0.194	0.194	0.197	0.227	0.227	0.225	
													3-Hour	0.501	0.329	0.334	0.339	0.458	0.473	0.491	0.414	0.414	0.425	0.517	0.515	0.510	
													1-Hour	0.948	0.633	0.645	0.660	0.893	0.911	0.932	0.761	0.760	0.770	0.861	0.858	0.847	
NO _x /NO ₂	22.1	17.5	16.9	15.9	24.2	23.6	22.3	13.6	13.1	12.0	10.8	10.4	9.6	Annual	0.0163	0.0117	0.1115	0.0111	0.0170	0.0170	0.0165	0.0105	0.0102	0.0095	0.0093	0.0090	0.0083
													24-Hour	0.1634	0.1214	0.1186	0.1139	0.1720	0.1731	0.1667	0.1057	0.1021	0.0948	0.0978	0.0947	0.0872	
													8-Hour	0.3467	0.2414	0.238	0.2268	0.3504	0.3524	0.3476	0.2468	0.2388	0.2256	0.2367	0.2293	0.2112	
													3-Hour	0.7735	0.5178	0.523	0.4925	0.7690	0.7782	0.7741	0.5273	0.5108	0.4867	0.5376	0.5210	0.4797	
													1-Hour	1.4646	0.9960	0.1031	0.9599	1.4977	1.5000	1.4922	0.9693	0.9367	0.8815	0.8957	0.8672	0.7969	
CO	68.2	50.5	48.0	44.7	52.3	50.8	48.2	24.4	23.5	21.7	20.1	19.5	18.3	Annual	0.051	0.034	0.033	0.031	0.057	0.057	0.056	0.039	0.038	0.037	0.043	0.043	0.040
													24-Hour	0.512	0.350	0.338	0.320	0.578	0.572	0.560	0.390	0.383	0.372	0.433	0.433	0.404	
													8-Hour	1.072	0.696	0.671	0.637	1.157	1.151	1.131	0.743	0.729	0.709	0.814	0.814	0.764	
													3-Hour	2.392	1.493	1.447	1.383	2.661	2.673	2.672	1.646	1.618	1.581	1.807	1.799	1.691	
													1-Hour	4.53	2.87	2.80	2.70	5.324	5.322	5.317	3.24	3.22	3.17	3.68	3.68	3.52	
Excl. Oil Genere (10 g/s)	NA	NA	NA	NA	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	NA	NA	NA	NA	0.040	0.041	0.043	0.049	0.049	0.050	0.055	0.055	0.055
													24-Hour	NA	NA	NA	NA	0.435	0.446	0.465	0.533	0.536	0.532	0.566	0.566	0.565	
													8-Hour	NA	NA	NA	NA	0.836	0.865	0.908	1.007	1.014	1.026	1.188	1.188	1.184	
													3-Hour	NA	NA	NA	NA	1.658	1.714	1.811	2.075	2.094	2.127	2.406	2.405	2.396	
													1-Hour	NA	NA	NA	NA	2.913	3.016	3.254	3.862	3.908	3.987	4.667	4.664	4.642	
SO ₂	NA	NA	NA	NA	3.1	3.0	2.7	2.5	2.4	2.2	1.9	1.9	1.7	Annual	NA	NA	NA	NA	0.00154	0.00152	0.00145	0.00151	0.00146	0.00136	0.00134	0.00130	0.00119
													24-Hour	NA	NA	NA	NA	0.0170	0.0166	0.0157	0.0159	0.0154	0.0142	0.0138	0.0134	0.0123	
													8-Hour	NA	NA	NA	NA	0.0326	0.0322	0.0306	0.0312	0.0302	0.0280	0.0291	0.0281	0.0258	
													3-Hour	NA	NA	NA	NA	0.0646	0.0639	0.0610	0.0643	0.0624	0.0580	0.0589	0.0569	0.0523	
													1-Hour	NA	NA	NA	NA	0.1136	0.1132	0.1096	0.1197	0.1164	0.1087	0.1142	0.1104	0.1013	
PM ₁₀	NA	NA	NA	NA	17.6	17.6	17.5	17.5	17.5	17.4	17.4	17.4	17.4	Annual	NA	NA	NA	NA	0.0088	0.0090	0.0095	0.0107	0.0108	0.0109	0.0120	0.0120	0.0120
													24-Hour	NA	NA	NA	NA	0.097	0.099	0.103	0.113	0.114	0.115	0.124	0.124	0.123	
													8-Hour	NA	NA	NA	NA	0.186	0.192	0.201	0.222	0.223	0.226	0.260	0.260	0.259	
													3-Hour	NA	NA	NA	NA	0.368	0.380	0.400	0.457	0.461	0.467	0.527	0.527	0.524	
													1-Hour	NA	NA	NA	NA	0.647	0.673	0.719	0.831	0.861	0.876	1.023	1.021	1.015	
NO _x /NO ₂	NA	NA	NA	NA	79.5	76.0	68.6	62.5	60.1	55.0	49.0	47.4	43.6	Annual	NA	NA	NA	NA	0.0396	0.0391	0.0372	0.0383	0.0371	0.0345	0.0338	0.0327	0.0300
													24-Hour	NA	NA	NA	NA	0.4359	0.4271	0.4023	0.4039	0.3910	0.3619	0.3488	0.3375	0.3163	
													8-Hour	NA	NA	NA	NA	0.8368	0.8279	0.7843	0.7930	0.7683	0.7119	0.7330	0.7090	0.6506	
													3-Hour	NA	NA	NA	NA	1.6602	1.6410	1.5639	1.6345	1.5859	1.4754	1.4840	1.4349	1.3164	
													1-Hour	NA	NA	NA	NA	2.9177	2.9077	2.8135	3.0427	2.9616	2.7655	2.8785	2.7828	2.5906	
CO	NA	NA	NA	NA	68.1	64.7	58.9	53.5	51.7	48.3	44.3	43.2	41.0	Annual	NA	NA	NA	NA	0.034	0.033	0.032	0.033	0.032	0.030	0.031	0.030	0.028
													24-Hour	NA	NA	NA	NA	0.373	0.363	0.345	0.345	0.336	0.318	0.316	0.308	0.292	
													8-Hour	NA	NA	NA	NA	0.717	0.704	0.673	0.678	0.661	0.625	0.647	0.647	0.612	
													3-Hour	NA	NA	NA	NA	1.422	1.396	1.343	1.397	1.365	1.295	1.343	1.310	1.239	
													1-Hour	NA	NA	NA	NA	2.50	2.47	2.41	2.60	2.55	2.43	2.61	2.54	2.40	

^a Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service stations at Miami and Palm Beach International Airports, respectively.

^b Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

^c Duct firing included for power augmentation and 100% load operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of

550 mmBtu/hr (161 MW)

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ISCST3 OUTPUT FILE NUMBER 1 :TPGENGCC.O87
 ISCST3 OUTPUT FILE NUMBER 2 :TPGENGCC.O88
 ISCST3 OUTPUT FILE NUMBER 3 :TPGENGCC.O89
 ISCST3 OUTPUT FILE NUMBER 4 :TPGENGCC.O90
 ISCST3 OUTPUT FILE NUMBER 5 :TPGENGCC.O91

First title for last output file is: 1987 FPL TURKEY POINT 4 CTS GAS CC GENERIC EMIS. 10 G/S 9/30/03
 Second title for last output file is: SIG IMPACT ANALYSIS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: GC1035					
Annual	1987	0.16665	270.	3000.	87123124
	1988	0.15832	250.	3000.	88123124
	1989	0.18444	325.0	2000.0	89123124
	1990	0.16884	320.	2250.	90123124
	1991	0.16475	310.	2500.	91123124
HIGH 24-Hour	1987	2.10358	113.6	544.6	87101324
	1988	3.06038	62.9	483.1	88110424
	1989	2.61270	123.2	513.7	89102824
	1990	1.54612	320.0	2000.0	90052024
	1991	2.18580	66.3	506.2	91031824
HIGH 8-Hour	1987	4.68565	105.3	588.8	87041716
	1988	7.48150	62.9	483.1	88110416
	1989	4.40104	322.8	1038.9	89061516
	1990	4.33569	295.0	1900.0	90071116
	1991	4.23154	109.3	565.2	91021516
HIGH 3-Hour	1987	6.88787	101.7	615.0	87041715
	1988	10.00856	72.2	556.9	88112315
	1989	6.34958	101.7	615.0	89120915
	1990	6.11197	72.2	556.9	90052215
	1991	9.19643	69.4	530.8	91031815
HIGH 1-Hour	1987	12.16158	105.0	600.0	87081116
	1988	17.86447	72.2	556.9	88041211
	1989	12.75095	105.3	588.8	89092112
	1990	18.33063	72.2	556.9	90052215
	1991	17.60289	69.4	530.8	91031813
SOURCE GROUP ID: GC1059					
Annual	1987	0.17800	270.	3000.	87123124
	1988	0.16860	250.	3000.	88123124
	1989	0.19710	325.0	2000.0	89123124
	1990	0.17797	320.	2250.	90123124
	1991	0.17466	310.	2500.	91123124
HIGH 24-Hour	1987	2.19993	113.6	544.6	87101324
	1988	3.22993	62.9	483.1	88110424
	1989	2.72862	123.2	513.7	89102824
	1990	1.62376	320.0	2000.0	90052024
	1991	2.29282	66.3	506.2	91031824
HIGH 8-Hour	1987	4.89177	105.3	588.8	87041716
	1988	7.88547	62.9	483.1	88110416
	1989	4.62009	322.8	1038.9	89061516
	1990	4.52488	295.0	1900.0	90071116
	1991	4.51069	109.3	565.2	91021516
HIGH 3-Hour	1987	7.23186	101.7	615.0	87041715
	1988	10.73172	72.2	556.9	88112315
	1989	6.77677	101.7	615.0	89120915
	1990	7.38318	72.2	556.9	90052215
	1991	9.62698	69.4	530.8	91031815
HIGH 1-Hour	1987	12.75073	82.2	618.7	87030812
	1988	18.65278	72.2	556.9	88041211
	1989	13.44787	95.3	674.1	89022317
	1990	19.33880	72.2	556.9	90052215
	1991	18.44882	69.4	530.8	91031813
SOURCE GROUP ID: GC1095					
Annual	1987	0.19595	270.	2750.	87123124
	1988	0.18539	250.	2750.	88123124
	1989	0.21824	325.0	2000.0	89123124
	1990	0.19322	320.0	2000.0	90123124
	1991	0.19008	310.	2250.	91123124
HIGH 24-Hour					

	1987	2.43786	113.6	544.6	87101324
	1988	3.49635	62.9	483.1	88110424
	1989	2.90264	123.2	513.7	89102824
	1990	1.73688	320.0	2000.0	90052024
	1991	2.45613	66.3	506.2	91031824
HIGH 8-Hour					
	1987	5.19947	105.3	588.8	87041716
	1988	8.51844	62.9	483.1	88110416
	1989	5.03870	322.8	1038.9	89061516
	1990	4.80077	295.0	1800.0	90071116
	1991	4.96224	109.3	565.2	91021516
HIGH 3-Hour					
	1987	7.76907	101.7	615.0	87041715
	1988	12.10048	72.2	556.9	88112315
	1989	7.64186	101.7	615.0	89120915
	1990	7.97297	72.2	556.9	90052215
	1991	10.28717	69.4	530.8	91031815
HIGH 1-Hour					
	1987	14.24202	82.2	618.7	87030812
	1988	19.89661	72.2	556.9	88041211
	1989	16.43138	90.0	1000.0	89051811
	1990	20.93724	72.2	556.9	90052215
	1991	19.78172	69.4	530.8	91031813
SOURCE GROUP ID: GC7535					
Annual					
	1987	0.24619	270.	2250.	87123124
	1988	0.22711	250.	2250.	88123124
	1989	0.26680	325.0	1800.0	89123124
	1990	0.23752	320.0	1900.0	90123124
	1991	0.23923	315.0	1900.0	91123124
HIGH 24-Hour					
	1987	2.88974	113.6	544.6	87101324
	1988	4.12074	62.9	483.1	88110424
	1989	3.38754	123.2	513.7	89102824
	1990	2.14918	75.8	575.5	90030324
	1991	2.82476	66.3	506.2	91031824
HIGH 8-Hour					
	1987	6.02177	105.3	588.8	87041716
	1988	10.04839	62.9	483.1	88110416
	1989	6.02679	322.8	1038.9	89061516
	1990	5.64061	294.0	1765.7	90071116
	1991	5.87693	109.3	565.2	91021516
HIGH 3-Hour					
	1987	9.19061	101.7	615.0	87041715
	1988	14.82162	72.2	556.9	88112315
	1989	9.35443	101.7	615.0	89120915
	1990	9.15285	72.2	556.9	90052215
	1991	12.00024	101.7	615.0	91021518
HIGH 1-Hour					
	1987	17.21337	82.2	618.7	87030812
	1988	22.20094	72.2	556.9	88041211
	1989	17.55523	98.3	643.5	89120912
	1990	24.01749	72.2	556.9	90052215
	1991	22.29173	69.4	530.8	91031813
SOURCE GROUP ID: GC7559					
Annual					
	1987	0.24865	270.	2250.	87123124
	1988	0.22904	250.	2250.	88123124
	1989	0.26929	325.0	1800.0	89123124
	1990	0.23953	320.0	1900.0	90123124
	1991	0.24096	315.0	1900.0	91123124
HIGH 24-Hour					
	1987	2.94319	113.6	544.6	87101324
	1988	4.18669	62.9	483.1	88110424
	1989	3.43756	123.2	513.7	89102824
	1990	2.18955	75.8	575.5	90030324
	1991	2.85034	66.3	506.2	91031824
HIGH 8-Hour					
	1987	6.08674	105.3	588.8	87041716
	1988	10.21450	62.9	483.1	88110416
	1989	6.09577	322.8	1038.9	89061516
	1990	5.66879	294.0	1765.7	90071116
	1991	5.97002	109.3	565.2	91021516
HIGH 3-Hour					
	1987	9.35189	101.7	615.0	87041715
	1988	15.13044	72.2	556.9	88112315
	1989	9.55454	101.7	615.0	89120915
	1990	9.26112	72.2	556.9	90052215
	1991	12.22617	101.7	615.0	91021518
HIGH 1-Hour					
	1987	17.53678	82.2	618.7	87030812
	1988	22.44407	72.2	556.9	88041211
	1989	17.86211	98.3	643.5	89120912
	1990	24.32874	72.2	556.9	90052215

SOURCE GROUP ID:	1991	22.54842	69.4	530.8	91031813
Annual	GC7595				
	1987	0.26895	270.	2250.	87123124
	1988	0.24766	250.	2250.	88123124
	1989	0.28835	325.0	1700.0	89123124
	1990	0.25751	320.0	1800.0	90123124
	1991	0.25849	315.0	1800.0	91123124
HIGH 24-Hour					
	1987	3.22726	113.6	544.6	87101324
	1988	4.48046	62.9	483.1	88110424
	1989	3.71999	123.2	513.7	89102824
	1990	2.43607	75.8	575.5	90030324
	1991	3.03083	66.3	506.2	91031824
HIGH 8-Hour					
	1987	6.64576	113.6	544.6	87101308
	1988	10.94470	62.9	483.1	88110416
	1989	6.49633	322.8	1038.9	89061516
	1990	5.92014	294.0	1765.7	90071116
	1991	6.38875	109.3	565.2	91021516
HIGH 3-Hour					
	1987	10.06047	101.7	615.0	87041715
	1988	16.43852	72.2	556.9	88112315
	1989	10.39009	101.7	615.0	89120915
	1990	9.76866	72.2	556.9	90052215
	1991	13.17387	101.7	615.0	91021518
HIGH 1-Hour					
	1987	18.93364	82.2	618.7	87030812
	1988	23.46147	72.2	556.9	88041211
	1989	19.15269	98.3	643.5	89120912
	1990	25.68957	72.2	556.9	90052215
	1991	23.64853	69.4	530.8	91031813
SOURCE GROUP ID:	GC5035				
Annual					
	1987	0.36377	272.0	1733.4	87123124
	1988	0.33313	250.5	2095.5	88123124
	1989	0.38994	325.0	1400.0	89123124
	1990	0.35722	320.0	1500.0	90123124
	1991	0.35019	315.0	1500.0	91123124
HIGH 24-Hour					
	1987	4.36251	230.0	1800.0	87100924
	1988	5.58804	62.9	483.1	88110424
	1989	5.00796	123.2	513.7	89102824
	1990	3.20619	75.8	575.5	90030324
	1991	3.99483	283.6	1672.7	91052124
HIGH 8-Hour					
	1987	8.95903	113.6	544.6	87101308
	1988	13.64378	62.9	483.1	88110416
	1989	8.25102	322.8	1038.9	89061516
	1990	7.47067	294.0	1765.7	90071116
	1991	8.14066	109.3	565.2	91021516
HIGH 3-Hour					
	1987	12.95322	113.6	544.6	87101303
	1988	20.94459	72.2	556.9	88112315
	1989	13.21982	101.7	615.0	89120915
	1990	11.65667	72.2	556.9	90052215
	1991	16.36459	101.7	615.0	91021518
HIGH 1-Hour					
	1987	23.82467	82.2	618.7	87030812
	1988	26.90895	65.0	500.0	88110414
	1989	23.47959	98.3	643.5	89120912
	1990	30.36295	72.2	556.9	90052215
	1991	27.29869	69.4	530.8	91031813
SOURCE GROUP ID:	GC5059				
Annual					
	1987	0.36584	270.5	1747.6	87123124
	1988	0.33465	250.5	2095.5	88123124
	1989	0.39139	325.0	1400.0	89123124
	1990	0.35915	320.0	1500.0	90123124
	1991	0.35225	315.0	1500.0	91123124
HIGH 24-Hour					
	1987	4.42802	113.6	544.6	87101324
	1988	5.64714	62.9	483.1	88110424
	1989	5.09223	123.2	513.7	89102824
	1990	3.23685	75.8	575.5	90030324
	1991	4.02077	283.6	1672.7	91052124
HIGH 8-Hour					
	1987	9.10482	113.6	544.6	87101308
	1988	13.78222	62.9	483.1	88110416
	1989	8.28231	322.8	1038.9	89061516
	1990	7.46979	294.0	1765.7	90071116
	1991	8.23789	109.3	565.2	91021516
HIGH 3-Hour					
	1987	13.14163	113.6	544.6	87101303

	1988	21.16896	72.2	556.9	88112315
	1989	13.37098	101.7	615.0	89120915
	1990	11.71680	72.2	556.9	90052215
	1991	16.52695	101.7	615.0	91021518
HIGH 1-Hour	1987	24.05030	82.2	618.7	87030812
	1988	27.08256	65.0	500.0	88110414
	1989	23.69546	98.3	643.5	89120912
	1990	30.55147	72.2	556.9	90052215
	1991	27.45211	69.4	530.8	91031813
SOURCE GROUP ID: GC5095					
Annual	1987	0.36685	270.5	1747.6	87123124
	1988	0.33724	250.5	2095.5	88123124
	1989	0.39404	325.0	1400.0	89123124
	1990	0.36416	320.0	1500.0	90123124
	1991	0.35607	315.0	1500.0	91123124
HIGH 24-Hour	1987	4.59061	113.6	544.6	87101324
	1988	5.78104	62.9	483.1	88110424
	1989	5.28884	123.2	513.7	89102824
	1990	3.30860	75.8	575.5	90030324
	1991	4.06723	283.6	1672.7	91052124
HIGH 8-Hour	1987	9.44602	113.6	544.6	87101308
	1988	14.09463	62.9	483.1	88110416
	1989	8.32956	322.8	1038.9	89061516
	1990	7.44131	294.0	1765.7	90071116
	1991	8.46126	109.3	565.2	91021516
HIGH 3-Hour	1987	13.57959	113.6	544.6	87101303
	1988	21.67512	72.2	556.9	88112315
	1989	13.71684	101.7	615.0	89120915
	1990	11.83861	72.2	556.9	90052215
	1991	16.89522	101.7	615.0	91021518
HIGH 1-Hour	1987	24.55138	82.2	618.7	87030812
	1988	27.46516	65.0	500.0	88110414
	1989	24.18338	98.3	643.5	89120912
	1990	30.95940	72.2	556.9	90052215
	1991	27.78784	69.4	530.8	91031813
SOURCE GROUP ID: GC1035					
Annual	1987	0.14003	270.	3500.	87123124
	1988	0.13336	250.	3500.	88123124
	1989	0.15369	320.	2500.	89123124
	1990	0.14412	320.	2500.	90123124
	1991	0.14130	310.	2750.	91123124
HIGH 24-Hour	1987	1.86365	113.6	544.6	87101324
	1988	2.74680	62.9	483.1	88110424
	1989	2.30374	123.2	513.7	89102824
	1990	1.33177	320.	2250.	90052024
	1991	1.94602	66.3	506.2	91031824
HIGH 8-Hour	1987	4.15126	105.3	588.8	87041716
	1988	6.72738	62.9	483.1	88110416
	1989	3.89812	325.0	1009.9	89061516
	1990	3.78025	295.0	2000.0	90071116
	1991	3.77678	109.3	565.2	91021516
HIGH 3-Hour	1987	6.17674	101.7	615.0	87041715
	1988	8.89064	72.2	556.9	88112315
	1989	5.67732	101.7	615.0	89120915
	1990	5.57183	72.2	556.9	90052215
	1991	8.31977	69.4	530.8	91031815
HIGH 1-Hour	1987	10.97676	105.0	600.0	87081116
	1988	16.65284	72.2	556.9	88041211
	1989	11.49215	105.3	588.8	89092112
	1990	16.71357	72.2	556.9	90052215
	1991	16.26343	69.4	530.8	91031813
SOURCE GROUP ID: GC1059					
Annual	1987	0.15223	270.	3250.	87123124
	1988	0.14397	250.	3250.	88123124
	1989	0.16635	325.0	2000.0	89123124
	1990	0.15226	320.	2250.	90123124
	1991	0.15029	310.	2500.	91123124
HIGH 24-Hour	1987	1.93596	113.6	544.6	87101324
	1988	2.88294	62.9	483.1	88110424
	1989	2.39358	123.2	513.7	89102824
	1990	1.38904	320.	2250.	90052024

	1991	2.03047	66.3	506.2	91031824
HIGH 8-Hour	1987	4.31282	105.3	588.8	87041716
	1988	7.05254	62.9	483.1	88110416
	1989	4.04509	322.8	1038.9	89061516
	1990	3.92602	295.0	2000.0	90071116
	1991	3.99841	109.3	565.2	91021516
HIGH 3-Hour	1987	6.45040	101.7	615.0	87041715
	1988	9.42805	72.2	556.9	88112315
	1989	5.98608	101.7	615.0	89120915
	1990	5.84719	72.2	556.9	90052215
	1991	8.66837	69.4	530.8	91031815
HIGH 1-Hour	1987	11.29089	105.0	600.0	87081116
	1988	17.31287	72.2	556.9	88041211
	1989	12.11560	95.3	674.1	89022317
	1990	17.53908	72.2	556.9	90052215
	1991	16.96642	69.4	530.8	91031813
SOURCE GROUP ID:	GC1095				
Annual	1987	0.16553	270.	3000.	87123124
	1988	0.15544	250.	3000.	88123124
	1989	0.18071	325.0	2000.0	89123124
	1990	0.16346	320.	2250.	90123124
	1991	0.16143	310.	2500.	91123124
HIGH 24-Hour	1987	2.12625	113.6	544.6	87101324
	1988	3.09204	62.9	483.1	88110424
	1989	2.53354	123.2	513.7	89102824
	1990	1.47807	320.	2250.	90052024
	1991	2.16065	66.3	506.2	91031824
HIGH 8-Hour	1987	4.56322	105.3	588.8	87041716
	1988	7.55126	62.9	483.1	88110416
	1989	4.30764	322.8	1038.9	89061516
	1990	4.14831	295.0	2000.0	90071116
	1991	4.34220	109.3	565.2	91021516
HIGH 3-Hour	1987	6.87421	101.7	615.0	87041715
	1988	10.41233	72.2	556.9	88112315
	1989	6.59858	101.7	615.0	89120915
	1990	7.11243	72.2	556.9	90052215
	1991	9.19931	69.4	530.8	91031815
HIGH 1-Hour	1987	12.33082	82.2	618.7	87030812
	1988	18.30450	72.2	556.9	88041211
	1989	13.15099	95.3	674.1	89022317
	1990	18.79390	72.2	556.9	90052215
	1991	18.02615	69.4	530.8	91031813
All receptor computations reported with respect to a user-specified origin					
GRID	0.00	0.00			
DISCRETE	0.00	0.00			

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ISCST3 OUTPUT FILE NUMBER 1 :TPGCCPA.087
ISCST3 OUTPUT FILE NUMBER 2 :TPGCCPA.088
ISCST3 OUTPUT FILE NUMBER 3 :TPGCCPA.089
ISCST3 OUTPUT FILE NUMBER 4 :TPGCCPA.090
ISCST3 OUTPUT FILE NUMBER 5 :TPGCCPA.091

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AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)

Annual

HIGH 24-Hour

HIGH 8-Hour

HIGH 3-Hour

HIGH 1-Hour

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCB03R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :TPGENOCC.087

ISCST3 OUTPUT FILE NUMBER 2 :TPGENOCC.088

ISCST3 OUTPUT FILE NUMBER 3 :TPGENOCC.089

ISCST3 OUTPUT FILE NUMBER 4 :TPGENOCC.090

ISCST3 OUTPUT FILE NUMBER 5 :TPGENOCC.091

First title for last output file is: 1987 FPL TURKEY POINT 4 CTS OIL CC GENERIC EMIS. 10 G/S 9/30/03

Second title for last output file is: SIG IMPACT ANALYSIS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: OC1035					
Annual	1987	0.06661	270.	6250.	87123124
	1988	0.06339	250.	6000.	88123124
	1989	0.07305	320.	3750.	89123124
	1990	0.07103	320.	3500.	90123124
	1991	0.06716	310.	4000.	91123124
HIGH 24-Hour	1987	1.03519	118.3	527.3	87033124
	1988	1.54515	62.9	483.1	88110424
	1989	1.19048	123.2	513.7	89102824
	1990	0.68558	75.8	575.5	90030324
	1991	1.00820	66.3	506.2	91031824
HIGH 8-Hour	1987	2.18904	118.3	527.3	87101308
	1988	3.80210	62.9	483.1	88110416
	1989	2.49982	325.0	1009.9	89061516
	1990	1.79494	290.	2750.	90071116
	1991	2.20592	65.0	500.0	91031816
HIGH 3-Hour	1987	3.65285	101.7	615.0	87041715
	1988	5.15695	72.2	556.9	88112315
	1989	3.45487	325.0	1009.9	89061512
	1990	3.19196	72.2	556.9	90052215
	1991	4.86258	69.4	530.8	91031815
HIGH 1-Hour	1987	6.54944	105.0	600.0	87081116
	1988	10.74147	72.2	556.9	88041211
	1989	6.81953	105.3	588.8	89092112
	1990	9.57587	72.2	556.9	90052215
	1991	10.10492	69.4	530.8	91031813
SOURCE GROUP ID: OC1059					
Annual	1987	0.07261	270.	5250.	87123124
	1988	0.06924	250.	5500.	88123124
	1989	0.07963	320.	3500.	89123124
	1990	0.07675	320.	3500.	90123124
	1991	0.07294	310.	4000.	91123124
HIGH 24-Hour	1987	1.09157	118.3	527.3	87033124
	1988	1.64638	62.9	483.1	88110424
	1989	1.26051	123.2	513.7	89102824
	1990	0.72268	75.8	575.5	90030324
	1991	1.06857	66.3	506.2	91031824
HIGH 8-Hour	1987	2.46400	100.0	1200.0	87081116
	1988	4.06458	62.9	483.1	88110416
	1989	2.60645	325.0	1009.9	89061516
	1990	1.92400	295.0	2000.0	90071116
	1991	2.33372	65.0	500.0	91031816
HIGH 3-Hour	1987	3.83712	101.7	615.0	87041715
	1988	5.42613	72.2	556.9	88112315
	1989	3.59556	325.0	1009.9	89061512
	1990	3.45769	72.2	556.9	90052215
	1991	5.16628	69.4	530.8	91031815
HIGH 1-Hour	1987	6.86747	105.0	600.0	87081116
	1988	11.45895	72.2	556.9	88041211
	1989	7.15245	105.3	588.8	89092112
	1990	10.37305	72.2	556.9	90052215
	1991	10.74421	69.4	530.8	91031813
SOURCE GROUP ID: OC1095					
Annual	1987	0.08243	270.	4750.	87123124
	1988	0.07817	250.	5000.	88123124
	1989	0.09068	320.	3250.	89123124
	1990	0.08606	320.	3250.	90123124
	1991	0.08211	310.	3750.	91123124
HIGH 24-Hour					

	1987	1.19623	118.3	527.3	87033124
	1988	1.84948	62.9	483.1	88110424
	1989	1.45123	123.2	513.7	89102824
	1990	0.82977	310.	7000.	90010524
	1991	1.28205	66.3	506.2	91031824
HIGH 8-Hour					
	1987	2.69024	103.6	1051.2	87081116
	1988	4.55746	62.9	483.1	88110416
	1989	2.79632	325.0	1009.9	89061516
	1990	2.17168	295.0	2000.0	90071116
	1991	2.59192	65.0	500.0	91031816
HIGH 3-Hour					
	1987	4.16968	101.7	615.0	87041715
	1988	5.91401	72.2	556.9	88112315
	1989	3.86374	347.2	847.9	89060915
	1990	3.95011	72.2	556.9	90052215
	1991	5.78026	69.4	530.8	91031815
HIGH 1-Hour					
	1987	7.43682	105.0	600.0	87081116
	1988	12.76116	72.2	556.9	88041211
	1989	7.94064	95.3	674.1	89022317
	1990	11.85030	72.2	556.9	90052215
	1991	12.08536	69.4	530.8	91031813
SOURCE GROUP ID: OC7535					
Annual					
	1987	0.11887	270.	3500.	87123124
	1988	0.10940	250.	3750.	88123124
	1989	0.12644	320.	2750.	89123124
	1990	0.11620	320.	2750.	90123124
	1991	0.11537	310.	3000.	91123124
HIGH 24-Hour					
	1987	1.57916	118.3	527.3	87033124
	1988	2.44282	62.9	483.1	88110424
	1989	1.85682	123.2	513.7	89102824
	1990	1.16878	310.	6750.	90010524
	1991	1.65424	66.3	506.2	91031824
HIGH 8-Hour					
	1987	3.39196	105.3	588.8	87041716
	1988	5.98547	62.9	483.1	88110416
	1989	3.40869	325.0	1009.9	89061516
	1990	2.90996	295.0	2000.0	90071116
	1991	3.40954	109.3	565.2	91021516
HIGH 3-Hour					
	1987	5.33527	101.7	615.0	87041715
	1988	8.11713	72.2	556.9	88112315
	1989	5.18895	101.7	615.0	89120915
	1990	5.74726	72.2	556.9	90052215
	1991	7.36058	69.4	530.8	91031815
HIGH 1-Hour					
	1987	9.61925	82.2	618.7	87030812
	1988	15.81788	72.2	556.9	88041211
	1989	10.77284	95.3	674.1	89022317
	1990	15.49251	72.2	556.9	90052215
	1991	15.28839	69.4	530.8	91031813
SOURCE GROUP ID: OC7559					
Annual					
	1987	0.12172	270.	3500.	87123124
	1988	0.11204	250.	3750.	88123124
	1989	0.12936	320.	2500.	89123124
	1990	0.11876	320.	2750.	90123124
	1991	0.11789	310.	3000.	91123124
HIGH 24-Hour					
	1987	1.62531	118.3	527.3	87033124
	1988	2.50594	62.9	483.1	88110424
	1989	1.89170	123.2	513.7	89102824
	1990	1.19583	75.8	575.5	90030324
	1991	1.69252	66.3	506.2	91031824
HIGH 8-Hour					
	1987	3.45577	105.3	588.8	87041716
	1988	6.13630	62.9	483.1	88110416
	1989	3.48091	325.0	1009.9	89061516
	1990	2.96694	295.0	2000.0	90071116
	1991	3.51425	109.3	565.2	91021516
HIGH 3-Hour					
	1987	5.45697	101.7	615.0	87041715
	1988	8.43053	72.2	556.9	88112315
	1989	5.38816	101.7	615.0	89120915
	1990	5.89187	72.2	556.9	90052215
	1991	7.51860	69.4	530.8	91031815
HIGH 1-Hour					
	1987	9.96244	82.2	618.7	87030812
	1988	16.15162	72.2	556.9	88041211
	1989	11.10674	95.3	674.1	89022317
	1990	15.89555	72.2	556.9	90052215

SOURCE GROUP ID:	1991	15.63861	69.4	530.8	91031813
Annual	1987	0.12684	270.	3250.	87123124
	1988	0.11709	250.	3500.	88123124
	1989	0.13465	320.	2500.	89123124
	1990	0.12451	320.	2500.	90123124
	1991	0.12388	310.	2750.	91123124
HIGH 24-Hour	1987	1.71866	118.3	527.3	87033124
	1988	2.64056	62.9	483.1	88110424
	1989	1.95976	123.2	513.7	89102824
	1990	1.27024	75.8	575.5	90030324
	1991	1.75883	66.3	506.2	91031824
HIGH 8-Hour	1987	3.58268	105.3	588.8	87041716
	1988	6.46608	62.9	483.1	88110416
	1989	3.61669	325.0	1009.9	89061516
	1990	3.06537	295.0	2000.0	90071116
	1991	3.71769	109.3	565.2	91021516
HIGH 3-Hour	1987	5.72134	101.7	615.0	87041715
	1988	9.05132	72.2	556.9	88112315
	1989	5.78372	101.7	615.0	89120915
	1990	6.16826	72.2	556.9	90052215
	1991	7.81497	69.4	530.8	91031815
HIGH 1-Hour	1987	10.63648	82.2	618.7	87030812
	1988	16.79286	72.2	556.9	88041211
	1989	11.76170	95.3	674.1	89022317
	1990	16.67207	72.2	556.9	90052215
	1991	16.31141	69.4	530.8	91031813
SOURCE GROUP ID: OC5035					
Annual	1987	0.17261	270.	2750.	87123124
	1988	0.15856	250.	3000.	88123124
	1989	0.18590	325.0	2000.0	89123124
	1990	0.16796	320.	2250.	90123124
	1991	0.16888	310.	2500.	91123124
HIGH 24-Hour	1987	2.30902	118.3	527.3	87033124
	1988	3.44326	62.9	483.1	88110424
	1989	2.62784	123.2	513.7	89102824
	1990	1.77661	75.8	575.5	90030324
	1991	2.24422	109.3	565.2	91021524
HIGH 8-Hour	1987	4.79496	118.3	527.3	87101308
	1988	8.44168	62.9	483.1	88110416
	1989	4.47664	322.8	1038.9	89061516
	1990	4.19971	295.0	1900.0	90071116
	1991	4.86852	109.3	565.2	91021516
HIGH 3-Hour	1987	7.61946	101.7	615.0	87041715
	1988	12.37334	72.2	556.9	88112315
	1989	7.88620	101.7	615.0	89120915
	1990	7.71631	72.2	556.9	90052215
	1991	10.22523	101.7	615.0	91021518
HIGH 1-Hour	1987	14.31295	82.2	618.7	87030812
	1988	20.00161	72.2	556.9	88041211
	1989	15.15274	95.3	674.1	89022317
	1990	20.77531	72.2	556.9	90052215
	1991	19.75234	69.4	530.8	91031813
SOURCE GROUP ID: OC5059					
Annual	1987	0.17259	270.	2750.	87123124
	1988	0.15863	250.	3000.	88123124
	1989	0.18594	325.0	2000.0	89123124
	1990	0.16803	320.	2250.	90123124
	1991	0.16893	310.	2500.	91123124
HIGH 24-Hour	1987	2.33300	113.6	544.6	87101324
	1988	3.46979	62.9	483.1	88110424
	1989	2.64820	123.2	513.7	89102824
	1990	1.79188	75.8	575.5	90030324
	1991	2.25809	109.3	565.2	91021524
HIGH 8-Hour	1987	4.85431	118.3	527.3	87101308
	1988	8.50975	62.9	483.1	88110416
	1989	4.49136	322.8	1038.9	89061516
	1990	4.19408	295.0	1900.0	90071116
	1991	4.90422	109.3	565.2	91021516
HIGH 3-Hour	1987	7.68332	101.7	615.0	87041715

	1988	12.50233	72.2	556.9	88112315
	1989	7.97071	101.7	615.0	89120915
	1990	7.75768	72.2	556.9	90052215
	1991	10.32102	101.7	615.0	91021518
HIGH 1-Hour	1987	14.44366	82.2	618.7	87030812
	1988	20.10981	72.2	556.9	88041211
	1989	15.28218	95.3	674.1	89022317
	1990	20.90498	72.2	556.9	90052215
	1991	19.86378	69.4	530.8	91031813
SOURCE GROUP ID:	OC5095				
Annual	1987	0.17150	270.	2750.	87123124
	1988	0.15779	250.	3000.	88123124
	1989	0.18473	325.0	2000.0	89123124
	1990	0.16711	320.	2250.	90123124
	1991	0.16779	310.	2500.	91123124
HIGH 24-Hour	1987	2.37887	113.6	544.6	87101324
	1988	3.51230	62.9	483.1	88110424
	1989	2.68470	123.2	513.7	89102824
	1990	1.84568	75.8	575.5	90030324
	1991	2.30736	109.3	565.2	91021524
HIGH 8-Hour	1987	4.95966	118.3	527.3	87101308
	1988	8.62192	62.9	483.1	88110416
	1989	4.49914	322.8	1038.9	89061516
	1990	4.16438	295.0	1900.0	90071116
	1991	4.98157	109.3	565.2	91021516
HIGH 3-Hour	1987	7.79143	101.7	615.0	87041715
	1988	12.70945	72.2	556.9	88112315
	1989	8.10821	101.7	615.0	89120915
	1990	7.81378	72.2	556.9	90052215
	1991	10.47464	101.7	615.0	91021518
HIGH 1-Hour	1987	14.64628	82.2	618.7	87030812
	1988	20.27799	72.2	556.9	88041211
	1989	15.49047	95.3	674.1	89022317
	1990	21.09870	72.2	556.9	90052215
	1991	20.03343	69.4	530.8	91031813
All receptor computations reported with respect to a user-specified origin					
GRID	0.00	0.00			
DISCRETE	0.00	0.00			

```

**
*****
**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey2.INP
**
*****
**
**
*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
  TITLEONE 1987 FPL TURKEY POINT 4 CTS GAS CC GEN. EMIS. 10 G/S 10/28/03
  TITLETWO SIG IMPACT ANALYSIS
  MODELOPT DEFAULT CONC RURAL
  AVERTIME PERIOD 24 8 3 1
  POLLUTID GEN
  TERRHGTS FLAT
  RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (O= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord.      Y Coord. **
LOCATION GCA5035    POINT 0.000      0.000
LOCATION GCB5035    POINT 42.450      0.000
LOCATION GCC5035    POINT 127.960      0.000
LOCATION GCD5035    POINT 170.720      0.000
LOCATION GCA7535    POINT 0.000      0.000
LOCATION GCB7535    POINT 42.450      0.000
LOCATION GCC7535    POINT 127.960      0.000
LOCATION GCD7535    POINT 170.720      0.000
LOCATION GCA1035D   POINT 0.000      0.000
LOCATION GCB1035D   POINT 42.450      0.000
LOCATION GCC1035D   POINT 127.960      0.000
LOCATION GCD1035D   POINT 170.720      0.000
LOCATION GCA1035H   POINT 0.000      0.000
LOCATION GCB1035H   POINT 42.450      0.000
LOCATION GCC1035H   POINT 127.960      0.000
LOCATION GCD1035H   POINT 170.720      0.000
LOCATION GCA5059    POINT 0.000      0.000
LOCATION GCB5059    POINT 42.450      0.000
LOCATION GCC5059    POINT 127.960      0.000
LOCATION GCD5059    POINT 170.720      0.000
LOCATION GCA7559    POINT 0.000      0.000
LOCATION GCB7559    POINT 42.450      0.000
LOCATION GCC7559    POINT 127.960      0.000
LOCATION GCD7559    POINT 170.720      0.000
LOCATION GCA1059D   POINT 0.000      0.000
LOCATION GCB1059D   POINT 42.450      0.000
LOCATION GCC1059D   POINT 127.960      0.000
LOCATION GCD1059D   POINT 170.720      0.000
LOCATION GCA1059H   POINT 0.000      0.000
LOCATION GCB1059H   POINT 42.450      0.000
LOCATION GCC1059H   POINT 127.960      0.000
LOCATION GCD1059H   POINT 170.720      0.000
LOCATION GCA5095    POINT 0.000      0.000
LOCATION GCB5095    POINT 42.450      0.000
LOCATION GCC5095    POINT 127.960      0.000
LOCATION GCD5095    POINT 170.720      0.000

```

LOCATION	GCA7595	POINT	0.000	0.000
LOCATION	GCB7595	POINT	42.450	0.000
LOCATION	GCC7595	POINT	127.960	0.000
LOCATION	GCD7595	POINT	170.720	0.000
LOCATION	GCA1095D	POINT	0.000	0.000
LOCATION	GCB1095D	POINT	42.450	0.000
LOCATION	GCC1095D	POINT	127.960	0.000
LOCATION	GCD1095D	POINT	170.720	0.000
LOCATION	GCA1095H	POINT	0.000	0.000
LOCATION	GCB1095H	POINT	42.450	0.000
LOCATION	GCC1095H	POINT	127.960	0.000
LOCATION	GCD1095H	POINT	170.720	0.000

** Source Parameters **

** POINT:	SRCID	QS	HS	TS	VS	DS
** VOLUME:	SRCID	QS	HS	SYINIT	SZINIT	
** AREA:	SRCID	QS	RH	XINIT	YINIT	
** UNITS:		(g/s)	(m)	(K)	(m/s)	(m)
SRCPARAM	GCA5035	2.50	39.900	353.0	11.900	5.790
SRCPARAM	GCB5035	2.50	39.900	353.0	11.900	5.790
SRCPARAM	GCC5035	2.50	39.900	353.0	11.900	5.790
SRCPARAM	GCD5035	2.50	39.900	353.0	11.900	5.790
SRCPARAM	GCA7535	2.50	39.900	359.0	14.700	5.790
SRCPARAM	GCB7535	2.50	39.900	359.0	14.700	5.790
SRCPARAM	GCC7535	2.50	39.900	359.0	14.700	5.790
SRCPARAM	GCD7535	2.50	39.900	359.0	14.700	5.790
SRCPARAM	GCA1035D	2.50	39.900	360.0	18.600	5.790
SRCPARAM	GCB1035D	2.50	39.900	360.0	18.600	5.790
SRCPARAM	GCC1035D	2.50	39.900	360.0	18.600	5.790
SRCPARAM	GCD1035D	2.50	39.900	360.0	18.600	5.790
SRCPARAM	GCA1035H	2.50	39.900	369.0	18.900	5.790
SRCPARAM	GCB1035H	2.50	39.900	369.0	18.900	5.790
SRCPARAM	GCC1035H	2.50	39.900	369.0	18.900	5.790
SRCPARAM	GCD1035H	2.50	39.900	369.0	18.900	5.790
SRCPARAM	GCA5059	2.50	39.900	354.0	11.700	5.790
SRCPARAM	GCB5059	2.50	39.900	354.0	11.700	5.790
SRCPARAM	GCC5059	2.50	39.900	354.0	11.700	5.790
SRCPARAM	GCD5059	2.50	39.900	354.0	11.700	5.790
SRCPARAM	GCA7559	2.50	39.900	360.0	14.400	5.790
SRCPARAM	GCB7559	2.50	39.900	360.0	14.400	5.790
SRCPARAM	GCC7559	2.50	39.900	360.0	14.400	5.790
SRCPARAM	GCD7559	2.50	39.900	360.0	14.400	5.790
SRCPARAM	GCA1059D	2.50	39.900	360.0	17.800	5.790
SRCPARAM	GCB1059D	2.50	39.900	360.0	17.800	5.790
SRCPARAM	GCC1059D	2.50	39.900	360.0	17.800	5.790
SRCPARAM	GCD1059D	2.50	39.900	360.0	17.800	5.790
SRCPARAM	GCA1059H	2.50	39.900	369.0	18.200	5.790
SRCPARAM	GCB1059H	2.50	39.900	369.0	18.200	5.790
SRCPARAM	GCC1059H	2.50	39.900	369.0	18.200	5.790
SRCPARAM	GCD1059H	2.50	39.900	369.0	18.200	5.790
SRCPARAM	GCA5095	2.50	39.900	357.0	11.200	5.790
SRCPARAM	GCB5095	2.50	39.900	357.0	11.200	5.790
SRCPARAM	GCC5095	2.50	39.900	357.0	11.200	5.790
SRCPARAM	GCD5095	2.50	39.900	357.0	11.200	5.790
SRCPARAM	GCA7595	2.50	39.900	361.0	13.500	5.790
SRCPARAM	GCB7595	2.50	39.900	361.0	13.500	5.790
SRCPARAM	GCC7595	2.50	39.900	361.0	13.500	5.790
SRCPARAM	GCD7595	2.50	39.900	361.0	13.500	5.790
SRCPARAM	GCA1095D	2.50	39.900	361.0	16.500	5.790
SRCPARAM	GCB1095D	2.50	39.900	361.0	16.500	5.790
SRCPARAM	GCC1095D	2.50	39.900	361.0	16.500	5.790
SRCPARAM	GCD1095D	2.50	39.900	361.0	16.500	5.790
SRCPARAM	GCA1095H	2.50	39.900	369.0	17.200	5.790
SRCPARAM	GCB1095H	2.50	39.900	369.0	17.200	5.790
SRCPARAM	GCC1095H	2.50	39.900	369.0	17.200	5.790
SRCPARAM	GCD1095H	2.50	39.900	369.0	17.200	5.790

** Building Downwash **

BUILDHGT	GCA5035-GCA7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCA5035-GCA7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCA5035-GCA7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCA5035-GCA7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCA5035-GCA7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCA5035-GCA7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCB5035-GCB7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCB5035-GCB7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCB5035-GCB7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCB5035-GCB7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCB5035-GCB7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCB5035-GCB7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCB5035-GCB7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCC5035-GCC7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCC5035-GCC7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCC5035-GCC7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCC5035-GCC7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCC5035-GCC7595	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCC5035-GCC7595	29.60	29.60	29.60	29.60	29.60	29.60

```

SRCGROUP GC1035D GCA1035D GCB1035D GCC1035D GCD1035D
SRCGROUP GC1059D GCA1059D GCB1059D GCC1059D GCD1059D
SRCGROUP GC1095D GCA1095D GCB1095D GCC1095D GCD1095D
SRCGROUP GC7535 GCA7535 GCB7535 GCC7535 GCD7535
SRCGROUP GC7559 GCA7559 GCB7559 GCC7559 GCD7559

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SRCGROUP GC7595 GCA7595 GCB7595 GCC7595 GCD7595
SRCGROUP GC5035 GCA5035 GCB5035 GCC5035 GCD5035
SRCGROUP GC5059 GCA5059 GCB5059 GCC5059 GCD5059
SRCGROUP GC5095 GCA5095 GCB5095 GCC5095 GCD5095
SRCGROUP GC1035H GCA1035H GCB1035H GCC1035H GCD1035H
SRCGROUP GC1059H GCA1059H GCB1059H GCC1059H GCD1059H
SRCGROUP GC1095H GCA1095H GCB1095H GCC1095H GCD1095H

```

SO FINISHED

**

** ISCST3 Receptor Pathway

**

** GRID CENTERED ON HRSG STACK A- WESTERN MOST STACK

**

** DISCCART: DISCRETE, PLANT PROPERTY BOUNDARY, 50 M SPACING

** DISCCART: DISCRETE, BASED ON POLAR, 72 DIR, 5 DEG INTERVALS, 400- 2000 M, 100 SPACING
(400 M = MINIMUM DISTANCE TO PLANT BOUNDARY)

** UPOL1: POLAR, 36 DIR, 10 DEG INTERVALS, 2250-7000 M, 250 M SPACING

** (2250 M = APPROX. MAX. DISTANCE TO BOUNDARY)

** UPOL2: POLAR, 36 DIR, 10 DEG INTERVALS, 7500- 15000 M, 500 M SPACING

**

RE STARTING

GRIDPOLR UPOL1 STA

ORIG 0.00 0.00

DIST 2250 2500 2750 3000 3250 3500 3750 4000 4250 4500 4750

DIST 5000 5250 5500 5750 6000 6250 6500 6750 7000

GDIR 36 0.00 10.00

GRIDPOLR UPOL1 END

GRIDPOLR UPOL2 STA

ORIG 0.00 0.00

DIST 7500 8000 8500 9000 9500 10000 10500 11000 11500 12000

DIST 12500 13000 13500 14000 14500 15000

GDIR 36 1.00 10.00

GRIDPOLR UPOL2 END

DISCCART 0.00 900.00

DISCCART 0.00 1000.00

DISCCART 0.00 1100.00

DISCCART 0.00 1200.00

DISCCART 0.00 1300.00


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**
*****
**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey2.INP
**
*****
**
**
*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
TITLEONE 1987 FPL TURKEY POINT 4 CTS GAS CC GEN. EMIS. 10 G/S POWER AUG WITH DB 10/28/03
TITLETWO SIG IMPACT ANALYSIS
MODELOPT DEFAULT CONC RURAL
AVERTIME PERIOD 24 8 3 1
POLLUTID GEN
TERRHGT5 FLAT
RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (O= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord.      Y Coord. **
LOCATION GCAPA80      POINT      0.000      0.000
LOCATION GCBPA80      POINT      42.450      0.000
LOCATION GCCPA80      POINT      127.960     0.000
LOCATION GCDPA80      POINT      170.720     0.000
** Source Parameters **
** POINT:  SRCID      QS      HS      TS      VS      DS
** VOLUME: SRCID      QS      HS      SYINIT  SZINIT
** AREA:    SRCID      QS      RH      XINIT   YINIT
** UNITS:    (g/s)      (m)      (K)      (m/s)      (m)
SRCPARAM GCAPA80      2.50      39.900     360.0     16.500     5.790
SRCPARAM GCBPA80      2.50      39.900     360.0     16.500     5.790
SRCPARAM GCCPA80      2.50      39.900     360.0     16.500     5.790
SRCPARAM GCDPA80      2.50      39.900     360.0     16.500     5.790
** Building Downwash **
BUILDHGT GCAPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCAPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCAPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCAPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCAPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCAPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCBPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCBPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCBPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCBPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCBPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCBPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCCPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCCPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCCPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCCPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCCPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCCPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCDPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCDPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCDPA80      29.60 29.60 29.60 29.60 29.60 29.60
BUILDHGT GCDPA80      29.60 29.60 29.60 29.60 29.60 29.60

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BUILDHGT	GCDPA80	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	GCDPA80	29.60	29.60	29.60	29.60	29.60	29.60
BUILDWID	GCAPA80	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCAPA80	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCAPA80	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	GCAPA80	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCAPA80	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCAPA80	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCBPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCBPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCBPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCBPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCBPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCBPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCCPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCCPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCCPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCCPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCCPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCCPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCDPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCDPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCDPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCDPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCDPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCDPA80	31.00	28.65	25.42	21.41	16.76	11.60
SRCGROUP	GCAPA80 GCBPA80 GCCPA80 GCDPA80						

SO FINISHED

**

** ISCST3 Receptor Pathway

**

** GRID CENTERED ON HRSG STACK A- WESTERN MOST STACK

**

** DISCCART: DISCRETE, PLANT PROPERTY BOUNDARY, 50 M SPACING

** DISCCART: DISCRETE, BASED ON POLAR, 72 DIR, 5 DEG INTERVALS, 400- 2000 M, 100 SPACING

** (400 M = MINIMUM DISTANCE TO PLANT BOUNDARY)

** UPOL1: POLAR, 36 DIR, 10 DEG INTERVALS, 2250-7000 M, 250 M SPACING

** (2250 M = APPROX. MAX. DISTANCE TO BOUNDARY)

** UPOL2: POLAR, 36 DIR, 10 DEG INTERVALS, 7500- 15000 M, 500 M SPACING

**

RE STARTING

GRIDPOLR UPOL1 STA

ORIG 0.00 0.00

DIST 2250 2500 2750 3000 3250 3500 3750 4000 4250 4500 4750

DIST 5000 5250 5500 5750 6000 6250 6500 6750 7000

GDIR 36 0.00 10.00

GRIDPOLR UPOL1 END

GRIDPOLR UPOL2 STA

ORIG 0.00 0.00

DIST 7500 8000 8500 9000 9500 10000 10500 11000 11500 12000

DIST 12500 13000 13500 14000 14500 15000

GDIR 36 1.00 10.00

GRIDPOLR UPOL2 END

DISCCART 0.00 900.00

DISCCART 0.00 1000.00

DISCCART 0.00 1100.00

DISCCART 0.00 1200.00

DISCCART 0.00 1300.00

DISCCART 0.00 1400.00

DISCCART 0.00 1500.00

DISCCART 0.00 1600.00

DISCCART 0.00 1700.00

DISCCART 0.00 1800.00

DISCCART 0.00 1900.00

DISCCART 0.00 2000.00

DISCCART 78.44 896.58

DISCCART 87.16 996.19

DISCCART 95.87 1095.81

DISCCART 104.59 1195.43

DISCCART 113.30 1295.05

DISCCART 122.02 1394.67

DISCCART 130.73 1494.29

DISCCART 139.45 1593.91

DISCCART 148.16 1693.53

DISCCART 156.88 1793.15

DISCCART 165.60 1892.77

DISCCART 174.31 1992.39

DISCCART 156.28 886.33

DISCCART 173.65 984.81

DISCCART 191.01 1083.29

DISCCART 208.38 1181.77

DISCCART 225.74 1280.25
DISCCART 243.11 1378.73
DISCCART 260.47 1477.21
DISCCART 277.84 1575.69
DISCCART 295.20 1674.17
DISCCART 312.57 1772.65
DISCCART 329.93 1871.13
DISCCART 347.30 1969.62
DISCCART 232.94 869.33
DISCCART 258.82 965.93
DISCCART 284.70 1062.52
DISCCART 310.58 1159.11
DISCCART 336.46 1255.70
DISCCART 362.35 1352.30
DISCCART 388.23 1448.89
DISCCART 414.11 1545.48
DISCCART 439.99 1642.07
DISCCART 465.87 1738.67
DISCCART 491.76 1835.26
DISCCART 517.64 1931.85
DISCCART 307.82 845.72
DISCCART 342.02 939.69
DISCCART 376.22 1033.66
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DISCCART -310.58 1159.11
DISCCART -336.46 1255.70
DISCCART -362.35 1352.30
DISCCART -388.23 1448.89
DISCCART -414.11 1545.48
DISCCART -439.99 1642.07
DISCCART -465.87 1738.67
DISCCART -491.76 1835.26
DISCCART -517.64 1931.85
DISCCART -156.28 886.33
DISCCART -173.65 984.81
DISCCART -191.01 1083.29
DISCCART -208.38 1181.77
DISCCART -225.74 1280.25
DISCCART -243.11 1378.73
DISCCART -260.47 1477.21
DISCCART -277.84 1575.69
DISCCART -295.20 1674.17
DISCCART -312.57 1772.65
DISCCART -329.93 1871.13
DISCCART -347.30 1969.62
DISCCART -78.44 896.58
DISCCART -87.16 996.19

DISCCART -95.87 1095.81
DISCCART -104.59 1195.43
DISCCART -113.30 1295.05
DISCCART -122.02 1394.67
DISCCART -130.73 1494.29
DISCCART -139.45 1593.91
DISCCART -148.16 1693.53
DISCCART -156.88 1793.15
DISCCART -165.60 1892.77
DISCCART -174.31 1992.39

** Discrete Cartesian Plant Boundary - Primary Receptors

DISCCART -1615.57 1042.56
DISCCART -1369.91 1042.56
DISCCART -1364.89 826.97
DISCCART 254.50 826.97
DISCCART 289.59 716.67
DISCCART 289.59 491.06
DISCCART 399.89 365.72
DISCCART 399.89 305.56
DISCCART 429.98 220.33
DISCCART 530.25 170.19
DISCCART 640.55 54.88
DISCCART 705.72 -30.35
DISCCART 429.98 -281.03
DISCCART 500.17 -276.02
DISCCART 570.36 -271.01
DISCCART 745.83 -130.63
DISCCART 755.86 -85.50
DISCCART 806.00 -95.53
DISCCART 841.09 -140.65
DISCCART 1016.57 -150.68
DISCCART 1031.61 -441.47
DISCCART 971.44 -561.79
DISCCART 871.17 -591.88
DISCCART 831.06 -707.19
DISCCART 836.08 -772.37
DISCCART 836.08 -857.60
DISCCART 821.04 -882.66
DISCCART -2036.71 -887.68
DISCCART -1610.56 440.93

** Discrete Cartesian Plant Boundary - Intermediate Receptors

DISCCART -1566.44 1042.56
DISCCART -1517.31 1042.56
DISCCART -1468.17 1042.56
DISCCART -1419.04 1042.56
DISCCART -1368.91 999.44
DISCCART -1367.90 956.32
DISCCART -1366.90 913.21
DISCCART -1365.89 870.09
DISCCART -1315.82 826.97
DISCCART -1266.75 826.97
DISCCART -1217.67 826.97
DISCCART -1168.60 826.97
DISCCART -1119.53 826.97
DISCCART -1070.46 826.97
DISCCART -1021.38 826.97
DISCCART -972.31 826.97
DISCCART -923.24 826.97
DISCCART -874.17 826.97
DISCCART -825.09 826.97
DISCCART -776.02 826.97
DISCCART -726.95 826.97
DISCCART -677.88 826.97
DISCCART -628.80 826.97
DISCCART -579.73 826.97
DISCCART -530.66 826.97
DISCCART -481.59 826.97
DISCCART -432.51 826.97
DISCCART -383.44 826.97
DISCCART -334.37 826.97
DISCCART -285.30 826.97
DISCCART -236.22 826.97
DISCCART -187.15 826.97
DISCCART -138.08 826.97
DISCCART -89.01 826.97
DISCCART -39.93 826.97
DISCCART 9.14 826.97
DISCCART 58.21 826.97
DISCCART 107.28 826.97
DISCCART 156.36 826.97
DISCCART 205.43 826.97
DISCCART 266.20 790.20
DISCCART 277.89 753.44
DISCCART 289.59 671.55

BEST AVAILABLE COPY

DISCCART 289.59 626.43
DISCCART 289.59 581.30
DISCCART 289.59 536.18
DISCCART 317.16 459.73
DISCCART 344.74 428.39
DISCCART 372.31 397.06
DISCCART 399.89 335.64
DISCCART 414.94 262.94
DISCCART 463.40 203.62
DISCCART 496.83 186.90
DISCCART 557.83 141.36
DISCCART 585.40 112.53
DISCCART 612.97 83.71
DISCCART 662.27 26.47
DISCCART 684.00 -1.94
DISCCART 671.25 -61.69
DISCCART 636.79 -93.02
DISCCART 602.32 -124.35
DISCCART 567.85 -155.69
DISCCART 533.38 -187.02
DISCCART 498.92 -218.36
DISCCART 464.45 -249.69
DISCCART 465.08 -278.52
DISCCART 535.26 -273.51
DISCCART 605.45 -242.93
DISCCART 640.55 -214.86
DISCCART 675.64 -186.78
DISCCART 710.74 -158.71
DISCCART 780.93 -90.52
DISCCART 823.55 -118.09
DISCCART 884.96 -143.16
DISCCART 928.83 -145.67
DISCCART 972.70 -148.17
DISCCART 1019.08 -199.15
DISCCART 1021.58 -247.61
DISCCART 1024.09 -296.08
DISCCART 1026.60 -344.54
DISCCART 1029.10 -393.00
DISCCART 1011.55 -481.58
DISCCART 991.50 -521.68
DISCCART 938.02 -571.82
DISCCART 904.59 -581.85
DISCCART 857.80 -630.32
DISCCART 844.43 -668.75
DISCCART 833.57 -739.78
DISCCART 836.08 -814.99
DISCCART 771.77 -882.75
DISCCART 722.50 -882.83
DISCCART 673.23 -882.92
DISCCART 623.95 -883.01
DISCCART 574.68 -883.09
DISCCART 525.41 -883.18
DISCCART 476.14 -883.27
DISCCART 426.87 -883.35
DISCCART 377.60 -883.44
DISCCART 328.32 -883.53
DISCCART 279.05 -883.61
DISCCART 229.78 -883.70
DISCCART 180.51 -883.79
DISCCART 131.24 -883.87
DISCCART 81.97 -883.96
DISCCART 32.70 -884.04
DISCCART -16.58 -884.13
DISCCART -65.85 -884.22
DISCCART -115.12 -884.30
DISCCART -164.39 -884.39
DISCCART -213.66 -884.48
DISCCART -262.93 -884.56
DISCCART -312.21 -884.65
DISCCART -361.48 -884.74
DISCCART -410.75 -884.82
DISCCART -460.02 -884.91
DISCCART -509.29 -885.00
DISCCART -558.56 -885.08
DISCCART -607.83 -885.17
DISCCART -657.11 -885.26
DISCCART -706.38 -885.34
DISCCART -755.65 -885.43
DISCCART -804.92 -885.52
DISCCART -854.19 -885.60
DISCCART -903.46 -885.69
DISCCART -952.74 -885.78
DISCCART -1002.01 -885.86
DISCCART -1051.28 -885.95

DISCCART -1100.55 -886.04
DISCCART -1149.82 -886.12
DISCCART -1199.09 -886.21
DISCCART -1248.37 -886.30
DISCCART -1297.64 -886.38
DISCCART -1346.91 -886.47
DISCCART -1396.18 -886.55
DISCCART -1445.45 -886.64
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DISCCART -1543.99 -886.81
DISCCART -1593.27 -886.90
DISCCART -1642.54 -886.99
DISCCART -1691.81 -887.07
DISCCART -1741.08 -887.16
DISCCART -1790.35 -887.25
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DISCCART -1888.90 -887.42
DISCCART -1938.17 -887.51
DISCCART -1987.44 -887.59
DISCCART -2021.49 -840.23
DISCCART -2006.27 -792.78
DISCCART -1991.05 -745.33
DISCCART -1975.83 -697.88
DISCCART -1960.61 -650.43
DISCCART -1945.39 -602.98
DISCCART -1930.17 -555.53
DISCCART -1914.95 -508.08
DISCCART -1899.73 -460.63
DISCCART -1884.51 -413.18
DISCCART -1869.29 -365.73
DISCCART -1854.07 -318.28
DISCCART -1838.85 -270.83
DISCCART -1823.63 -223.37
DISCCART -1808.42 -175.92
DISCCART -1793.20 -128.47
DISCCART -1777.98 -81.02
DISCCART -1762.76 -33.57
DISCCART -1747.54 13.88
DISCCART -1732.32 61.33
DISCCART -1717.10 108.78
DISCCART -1701.88 156.23
DISCCART -1686.66 203.68
DISCCART -1671.44 251.13
DISCCART -1656.22 298.58
DISCCART -1641.00 346.03
DISCCART -1625.78 393.48
DISCCART -1610.95 487.21
DISCCART -1611.33 533.49
DISCCART -1611.72 579.77
DISCCART -1612.10 626.05
DISCCART -1612.49 672.33
DISCCART -1612.87 718.61
DISCCART -1613.26 764.88
DISCCART -1613.64 811.16
DISCCART -1614.03 857.44
DISCCART -1614.41 903.72
DISCCART -1614.80 950.00
DISCCART -1615.18 996.28

RE FINISHED

**

** ISCST3 Meteorology Pathway

**

**

ME STARTING

ME INPUTFIL C:\MET\MIAPBI87.ASC

ME ANEMHGHT 33 FEET

ME SURFDATA 12839 1987 MIAMI

ME UAIRDATA 12844 1987 PALM_BEACH_INTER

ME WINDCATS 1.54 3.09 5.14 8.23 10.80

ME FINISHED

OU STARTING

OU RECTABLE ALLAVE FIRST

OU FINISHED

```

**
*****
**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey2.INP
**
*****
**
**
*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
  TITLEONE 1987 FPL TURKEY POINT 4 CTS OIL CC GENERIC EMIS. 10 G/S    9/30/03
  TITLETWO SIG IMPACT ANALYSIS
  MODELOPT DFAULT CONC RURAL
  AVERTIME PERIOD 24 8 3 1
  POLLUTID GEN
  TERRHGTS FLAT
  RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (O= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord.      Y Coord. **
LOCATION OCA5035    POINT  0.000          0.000
LOCATION OCB5035    POINT  42.450          0.000
LOCATION OCC5035    POINT  127.960         0.000
LOCATION OCD5035    POINT  170.720         0.000
LOCATION OCA7535    POINT  0.000          0.000
LOCATION OCB7535    POINT  42.450          0.000
LOCATION OCC7535    POINT  127.960         0.000
LOCATION OCD7535    POINT  170.720         0.000
LOCATION OCA1035    POINT  0.000          0.000
LOCATION OCB1035    POINT  42.450          0.000
LOCATION OCC1035    POINT  127.960         0.000
LOCATION OCD1035    POINT  170.720         0.000
LOCATION OCA5059    POINT  0.000          0.000
LOCATION OCB5059    POINT  42.450          0.000
LOCATION OCC5059    POINT  127.960         0.000
LOCATION OCD5059    POINT  170.720         0.000
LOCATION OCA7559    POINT  0.000          0.000
LOCATION OCB7559    POINT  42.450          0.000
LOCATION OCC7559    POINT  127.960         0.000
LOCATION OCD7559    POINT  170.720         0.000
LOCATION OCA1059    POINT  0.000          0.000
LOCATION OCB1059    POINT  42.450          0.000
LOCATION OCC1059    POINT  127.960         0.000
LOCATION OCD1059    POINT  170.720         0.000
LOCATION OCA5095    POINT  0.000          0.000
LOCATION OCB5095    POINT  42.450          0.000
LOCATION OCC5095    POINT  127.960         0.000
LOCATION OCD5095    POINT  170.720         0.000
LOCATION OCA7595    POINT  0.000          0.000
LOCATION OCB7595    POINT  42.450          0.000
LOCATION OCC7595    POINT  127.960         0.000
LOCATION OCD7595    POINT  170.720         0.000
LOCATION OCA1095    POINT  0.000          0.000
LOCATION OCB1095    POINT  42.450          0.000
LOCATION OCC1095    POINT  127.960         0.000
LOCATION OCD1095    POINT  170.720         0.000

```

Source Parameters						
** POINT:	SRCID	QS	HS	TS	VS	DS
** VOLUME:	SRCID	QS	HS	SYINIT	SZINIT	
** AREA:	SRCID	QS	RH	XINIT	YINIT	
** UNITS:		(g/s)	(m)	(K)	(m/s)	(m)
SRCPARAM	OCA5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCB5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCC5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCD5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCA7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCB7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCC7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCD7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCA1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCB1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCC1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCD1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCA5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCB5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCC5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCD5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCA7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCB7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCC7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCD7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCA1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCB1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCC1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCD1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCA5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCB5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCC5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCD5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCA7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCB7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCC7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCD7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCA1095	2.50	39.900	418.0	19.700	5.790
SRCPARAM	OCB1095	2.50	39.900	418.0	19.700	5.790
SRCPARAM	OCC1095	2.50	39.900	418.0	19.700	5.790
SRCPARAM	OCD1095	2.50	39.900	418.0	19.700	5.790

BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDWID	OCA1035-OCA7595	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	OCA1035-OCA7595	31.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCA1035-OCA7595	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	OCA1035-OCA7595	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	OCA1035-OCA7595	31.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCA1035-OCA7595	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	OCB1035-OCB7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCB1035-OCB7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCB1035-OCB7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCB1035-OCB7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCB1035-OCB7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCB1035-OCB7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCC1035-OCC7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCC1035-OCC7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCC1035-OCC7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCC1035-OCC7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCC1035-OCC7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCC1035-OCC7595	31.00	28.65	25.42	21.41	16.76	11.60

BUILDWID	OCD1035-OCD7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCD1035-OCD7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCD1035-OCD7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCD1035-OCD7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCD1035-OCD7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCD1035-OCD7595	31.00	28.65	25.42	21.41	16.76	11.60

SRCGROUP	OC1035	OCA1035	OCB1035	OCC1035	OCD1035
SRCGROUP	OC1059	OCA1059	OCB1059	OCC1059	OCD1059
SRCGROUP	OC1095	OCA1095	OCB1095	OCC1095	OCD1095
SRCGROUP	OC7535	OCA7535	OCB7535	OCC7535	OCD7535
SRCGROUP	OC7559	OCA7559	OCB7559	OCC7559	OCD7559
SRCGROUP	OC7595	OCA7595	OCB7595	OCC7595	OCD7595
SRCGROUP	OC5035	OCA5035	OCB5035	OCC5035	OCD5035
SRCGROUP	OC5059	OCA5059	OCB5059	OCC5059	OCD5059
SRCGROUP	OC5095	OCA5095	OCB5095	OCC5095	OCD5095

SO FINISHED

**

** ISCST3 Receptor Pathway

**

** GRID CENTERED ON HRSG STACK A- WESTERN MOST STACK

**

** DISCCART: DISCRETE, PLANT PROPERTY BOUNDARY, 50 M SPACING

** DISCCART: DISCRETE, BASED ON POLAR, 72 DIR, 5 DEG INTERVALS, 400- 2000 M, 100 SPACING

(400 M = MINIMUM DISTANCE TO PLANT BOUNDARY)

** UPOL1: POLAR, 36 DIR, 10 DEG INTERVALS, 2250-7000 M, 250 M SPACING

(2250 M = APPROX. MAX. DISTANCE TO BOUNDARY)

** UPOL2: POLAR, 36 DIR, 10 DEG INTERVALS, 7500- 15000 M, 500 M SPACING

**

RE STARTING

GRIDPOLR UPOL1 STA

ORIG 0.00 0.00

DIST 2250 2500 2750 3000 3250 3500 3750 4000 4250 4500 4750

DIST 5000 5250 5500 5750 6000 6250 6500 6750 7000

GDIR 36 0.00 10.00

GRIDPOLR UPOL1 END

GRIDPOLR UPOL2 STA

ORIG 0.00 0.00

DIST 7500 8000 8500 9000 9500 10000 10500 11000 11500 12000

DIST 12500 13000 13500 14000 14500 15000

GDIR 36 1.00 10.00

GRIDPOLR UPOL2 END

DISCCART 0.00 900.00

DISCCART 0.00 1000.00

ISCB03R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :TPPMGCTW.087
 ISCST3 OUTPUT FILE NUMBER 2 :TPPMGCTW.088
 ISCST3 OUTPUT FILE NUMBER 3 :TPPMGCTW.089
 ISCST3 OUTPUT FILE NUMBER 4 :TPPMGCTW.090
 ISCST3 OUTPUT FILE NUMBER 5 :TPPMGCTW.091

First title for last output file is: 1987 FPL TURKEY POINT 4 CTS GAS CC- 50% LOAD 95 F- PM EMIS. WITH COOLING TWR
 Second title for last output file is: SIG IMPACT ANALYSIS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)

SOURCE GROUP ID: GC5095					
Annual	1987	0.18783	270.5	1747.6	87123124
	1988	0.17266	250.5	2095.5	88123124
	1989	0.20175	325.0	1400.0	89123124
	1990	0.18645	320.0	1500.0	90123124
	1991	0.18231	315.0	1500.0	91123124
HIGH 24-Hour	1987	2.35039	113.6	544.6	87101324
	1988	2.95989	62.9	483.1	88110424
	1989	2.70789	123.2	513.7	89102824
	1990	1.69400	75.8	575.5	90030324
	1991	2.08242	283.6	1672.7	91052124
SOURCE GROUP ID: COOLTW					
Annual	1987	0.00762	327.3	982.6	87123124
	1988	0.00994	325.0	1009.9	88123124
	1989	0.01362	329.8	957.0	89123124
	1990	0.01067	327.3	982.6	90123124
	1991	0.01026	325.0	1009.9	91123124
HIGH 24-Hour	1987	0.14845	52.6	503.3	87021624
	1988	0.23223	57.6	491.2	88110424
	1989	0.15139	62.9	483.1	89092124
	1990	0.18533	62.9	483.1	90052924
	1991	0.21429	62.9	483.1	91031824
SOURCE GROUP ID: ALL					
Annual	1987	0.19340	272.0	1733.4	87123124
	1988	0.17755	250.5	2095.5	88123124
	1989	0.21198	325.0	1400.0	89123124
	1990	0.19427	320.0	1400.0	90123124
	1991	0.19054	315.0	1400.0	91123124
HIGH 24-Hour	1987	2.36580	113.6	544.6	87101324
	1988	3.15211	62.9	483.1	88110424
	1989	2.76583	123.2	513.7	89102824
	1990	1.74282	75.8	575.5	90030324
	1991	2.23388	65.0	500.0	91031824
All receptor computations reported with respect to a user-specified origin					
GRID	0.00	0.00			
DISCRETE	0.00	0.00			

ISCB0B3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :TPPMOCTW.O87
 ISCST3 OUTPUT FILE NUMBER 2 :TPPMOCTW.O88
 ISCST3 OUTPUT FILE NUMBER 3 :TPPMOCTW.O89
 ISCST3 OUTPUT FILE NUMBER 4 :TPPMOCTW.O90
 ISCST3 OUTPUT FILE NUMBER 5 :TPPMOCTW.O91

First title for last output file is: 1987 FPL TURKEY PT 4 CTS OIL CC- 50% LOAD 95F- PM COOLING TWR 10/28/03
 Second title for last output file is: SIG IMPACT ANALYSIS TWR:0.001% DRIFT 2.35 LB/HR

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)

SOURCE GROUP ID: OC5095					
Annual	1987	0.15488	270.	4750.	87123124
	1988	0.15151	250.	4250.	88123124
	1989	0.15405	320.	3000.	89123124
	1990	0.14131	320.	2750.	90123124
	1991	0.14323	310.	3500.	91123124
HIGH 24-Hour	1987	2.32191	250.	3000.	87030624
	1988	3.94815	62.9	483.1	88110424
	1989	2.43875	101.7	615.0	89120924
	1990	1.80982	75.8	575.5	90030324
	1991	2.44996	105.3	588.8	91021524
SOURCE GROUP ID: COOLTW					
Annual	1987	0.04763	325.0	1009.9	87123124
	1988	0.06220	325.0	1009.9	88123124
	1989	0.08506	327.3	982.6	89123124
	1990	0.06736	327.3	982.6	90123124
	1991	0.06607	320.7	1069.3	91123124
HIGH 24-Hour	1987	0.94476	62.9	483.1	87042924
	1988	1.39265	62.9	483.1	88041224
	1989	0.98228	62.9	483.1	89092124
	1990	1.20429	62.9	483.1	90052924
	1991	1.32450	62.9	483.1	91031824
SOURCE GROUP ID: ALL					
Annual	1987	0.17461	270.	4250.	87123124
	1988	0.17000	250.	4000.	88123124
	1989	0.18622	320.	2500.	89123124
	1990	0.17042	320.	2500.	90123124
	1991	0.17060	310.	3000.	91123124
HIGH 24-Hour	1987	2.57617	230.	3000.	87100924
	1988	5.03712	60.0	500.0	88110424
	1989	2.64241	322.8	1038.9	89061524
	1990	2.11534	75.8	575.5	90030324
	1991	3.12550	62.9	483.1	91031824
All receptor computations reported with respect to a user-specified origin					
GRID	0.00	0.00			
DISCRETE	0.00	0.00			

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**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey3.INP
**
*****
**
**
*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
  TITLEONE 1987 FPL TURKEY POINT 4 CTS GAS CC- 50% LOAD 95 F- PM EMIS. WITH COOLING TWR 9/30/03
  TITLETWO SIG IMPACT ANALYSIS
  MODELOPT DFAULT CONC RURAL
  AVERTIME PERIOD 24
  POLLUTID GEN
  TERRHGTS FLAT
  RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (O= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord.      Y Coord. **
LOCATION GCA5095    POINT    0.000        0.000
LOCATION GCB5095    POINT    42.450        0.000
LOCATION GCC5095    POINT   127.960        0.000
LOCATION GCD5095    POINT   170.720        0.000

LOCATION CELL01 POINT    42.870    62.390
LOCATION CELL02 POINT    61.040    62.390
LOCATION CELL03 POINT    79.620    62.390
LOCATION CELL04 POINT    97.780    62.390
LOCATION CELL05 POINT   115.950    62.390
LOCATION CELL06 POINT   134.390    62.390
LOCATION CELL07 POINT   152.270    62.390
LOCATION CELL08 POINT   171.140    62.390
LOCATION CELL09 POINT   189.300    61.390
LOCATION CELL10 POINT   207.050    61.390
LOCATION CELL11 POINT   225.630    62.390
LOCATION CELL12 POINT    42.870    43.810
LOCATION CELL13 POINT    61.040    43.810
LOCATION CELL14 POINT    79.620    43.810
LOCATION CELL15 POINT    97.780    43.810
LOCATION CELL16 POINT   115.950    43.810
LOCATION CELL17 POINT   134.390    43.810
LOCATION CELL18 POINT   152.270    43.810
LOCATION CELL19 POINT   171.140    43.810
LOCATION CELL20 POINT   189.300    43.810
LOCATION CELL21 POINT   207.050    43.810
LOCATION CELL22 POINT   225.630    43.810

** Source Parameters **
** POINT:  SRCID      QS      HS      TS      VS      DS
** VOLUME: SRCID      QS      HS      SYINIT  SZINIT
** AREA:   SRCID      QS      RH      XINIT   YINIT
** UNITS:   (g/s)      (m)      (K)      (m/s)      (m)
SRCPARAM GCA5095    1.28      39.900    357.0    11.200    5.790
SRCPARAM GCB5095    1.28      39.900    357.0    11.200    5.790
SRCPARAM GCC5095    1.28      39.900    357.0    11.200    5.790

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SRCPARAM	GCD5095	1.28	39.900	357.0	11.200	5.790

SRCPARAM	CELL01	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL02	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL03	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL04	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL05	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL06	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL07	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL08	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL09	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL10	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL11	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL12	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL13	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL14	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL15	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL16	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL17	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL18	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL19	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL20	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL21	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL22	0.0135	19.800	309.0	6.72	11.60

*** Building Downwash ***

BUILDHGT	GCA5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCA5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCA5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCA5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCA5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCB5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCD5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCD5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCD5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCD5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCD5095	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCD5095	26.50	26.50	26.50	26.50	26.50	26.50

BUILDWID	GCA5095	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	GCA5095	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCA5095	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCA5095	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	GCA5095	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCA5095	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCB5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCB5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCB5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCB5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCB5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCB5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCC5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCC5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCC5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCC5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCC5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCC5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCD5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCD5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCD5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCD5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCD5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCD5095	31.00	28.65	25.42	21.41	16.76	11.60

BUILDHGT	CELL01	26.50	26.50	26.50	26.50	15.50	15.50
BUILDHGT	CELL01	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL01	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL01	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL01	15.50	15.50	15.50	15.50	15.50	26.50
BUILDHGT	CELL01	26.50	26.50	15.50	15.50	26.50	26.50
BUILDHGT	CELL02	26.50	26.50	26.50	26.50	26.50	15.50
BUILDHGT	CELL02	15.50	15.50	15.50	15.50	15.50	15.50

Page: 3

BUILDHGT	CELL16	15.50	15.50	26.50	15.50	15.50	15.50
BUILDHGT	CELL16	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL16	15.50	15.50	15.50	15.50	15.50	26.50
BUILDHGT	CELL16	26.50	26.50	26.50	26.50	26.50	15.50
BUILDHGT	CELL17	26.50	26.50	15.50	15.50	26.50	26.50
BUILDHGT	CELL17	26.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	26.50	26.50	26.50	26.50	15.50	26.50
BUILDHGT	CELL18	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	CELL18	26.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL18	15.50	26.50	26.50	15.50	15.50	15.50
BUILDHGT	CELL18	15.50	15.50	26.50	26.50	15.50	15.50
BUILDHGT	CELL18	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL18	15.50	26.50	26.50	26.50	26.50	15.50
BUILDHGT	CELL19	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	CELL19	26.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	26.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	15.50	15.50	15.50	26.50	26.50
BUILDHGT	CELL20	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	26.50	26.50	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	26.50	26.50	26.50	26.50
BUILDHGT	CELL22	26.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50

BUILDWID	CELL01	16.76	21.51	25.55	28.82	157.03	132.08
BUILDWID	CELL01	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL01	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL01	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL01	103.11	71.01	36.75	71.01	103.11	32.42
BUILDWID	CELL01	31.00	28.65	192.01	200.98	16.76	11.60
BUILDWID	CELL02	16.76	21.41	25.55	28.82	31.21	132.08
BUILDWID	CELL02	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL02	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL02	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL02	103.11	71.01	36.75	71.01	103.11	32.42
BUILDWID	CELL02	31.00	28.65	25.42	200.98	203.84	200.50
BUILDWID	CELL03	203.84	21.41	25.42	28.65	31.21	132.08
BUILDWID	CELL03	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL03	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL03	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL03	103.11	71.01	36.75	71.01	103.11	32.42
BUILDWID	CELL03	31.00	28.65	25.42	21.41	203.84	200.50
BUILDWID	CELL04	203.84	200.98	25.42	28.65	31.00	32.66
BUILDWID	CELL04	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL04	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL04	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL04	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL04	31.00	28.65	25.42	21.41	16.76	200.50
BUILDWID	CELL05	203.84	200.98	25.42	28.65	31.00	32.66
BUILDWID	CELL05	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL05	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL05	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL05	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL05	31.00	28.65	25.42	21.41	16.76	200.50
BUILDWID	CELL06	16.76	200.98	192.01	28.65	31.00	32.42
BUILDWID	CELL06	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL06	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL06	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL06	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL06	157.03	28.65	25.42	21.41	203.84	11.60
BUILDWID	CELL07	16.76	21.41	25.42	177.21	31.00	32.42
BUILDWID	CELL07	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL07	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL07	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL07	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL07	157.03	177.21	25.42	21.41	16.76	200.50
BUILDWID	CELL08	16.76	21.41	25.42	28.65	157.03	132.08

BUILDWID CELL08 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL08 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL08 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL08 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL08 157.03 177.21 192.01 200.98 16.76 11.60
BUILDWID CELL09 16.76 21.41 25.42 28.65 31.00 132.08
BUILDWID CELL09 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL09 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL09 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL09 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL09 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL10 203.84 21.41 25.42 28.65 31.00 132.08
BUILDWID CELL10 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL10 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL10 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL10 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL10 157.03 177.21 192.01 200.98 203.84 200.50
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BUILDWID CELL11 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL11 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL11 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL11 103.11 71.01 36.75 71.01 103.11 132.08
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BUILDWID CELL12 16.76 21.51 25.55 28.82 31.21 132.08
BUILDWID CELL12 103.11 71.01 36.75 71.01 103.11 132.08
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BUILDWID CELL12 103.11 71.01 36.75 71.01 32.85 32.42
BUILDWID CELL12 31.00 28.65 192.01 200.98 16.76 11.60
BUILDWID CELL13 16.76 21.41 25.55 28.65 31.21 32.66
BUILDWID CELL13 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL13 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL13 203.84 200.98 25.42 28.65 157.03 132.08
BUILDWID CELL13 103.11 71.01 36.75 71.01 32.85 32.42
BUILDWID CELL13 31.00 28.65 192.01 200.98 203.84 200.50
BUILDWID CELL14 203.84 21.41 25.42 28.65 31.00 32.66
BUILDWID CELL14 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL14 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL14 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL14 103.11 71.01 36.75 71.01 32.85 32.42
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BUILDWID CELL15 203.84 200.98 25.42 28.65 31.00 32.42
BUILDWID CELL15 33.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL15 31.00 28.65 192.01 200.98 203.84 200.50
BUILDWID CELL15 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL15 103.11 71.01 36.75 71.01 103.11 32.42
BUILDWID CELL15 31.00 28.65 25.42 21.41 203.84 200.50
BUILDWID CELL16 203.84 200.98 192.01 28.65 31.00 32.42
BUILDWID CELL16 33.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL16 157.03 177.21 25.42 200.98 203.84 200.50
BUILDWID CELL16 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL16 103.11 71.01 36.75 71.01 103.11 32.42
BUILDWID CELL16 31.00 28.65 25.42 21.41 16.76 200.50
BUILDWID CELL17 16.76 21.41 192.01 177.21 31.00 32.42
BUILDWID CELL17 32.85 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL17 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL17 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL17 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL17 31.00 28.65 25.42 21.41 203.84 11.60
BUILDWID CELL18 16.76 21.41 25.42 28.65 31.00 32.42
BUILDWID CELL18 32.85 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL18 157.03 28.65 25.42 200.98 203.84 200.50
BUILDWID CELL18 203.84 200.98 25.42 28.65 157.03 132.08
BUILDWID CELL18 103.11 71.01 36.75 71.01 103.11 132.08
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BUILDWID CELL19 16.76 21.41 25.42 28.65 31.00 32.42
BUILDWID CELL19 32.85 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL19 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL19 203.84 21.41 192.01 177.21 157.03 132.08
BUILDWID CELL19 103.11 71.01 36.75 71.01 103.11 132.08
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BUILDWID CELL20 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL20 203.84 200.98 25.42 28.65 157.03 132.08
BUILDWID CELL20 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL20 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL21 203.84 21.41 25.42 28.65 31.00 32.42
BUILDWID CELL21 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL21 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL21 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL21 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL21 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL22 203.84 200.98 25.42 28.65 31.00 32.42

BUILDWID CELL22 32.85 71.01 36.75 71.01 103.11 132.08
 BUILDWID CELL22 157.03 177.21 192.01 200.98 203.84 200.50
 BUILDWID CELL22 203.84 200.98 192.01 177.21 157.03 132.08
 BUILDWID CELL22 103.11 71.01 36.75 71.01 103.11 132.08
 BUILDWID CELL22 157.03 177.21 192.01 200.98 203.84 200.50

SRCGROUP GC5095 GCA5095 GCB5095 GCC5095 GCD5095
 SRCGROUP COOLTW CELL01-CELL22
 SRCGROUP ALL

SO FINISHED

**

** ISCST3 Receptor Pathway

**

** GRID CENTERED ON HRSG STACK A- WESTERN MOST STACK

**

** DISCCART: DISCRETE, PLANT PROPERTY BOUNDARY, 50 M SPACING

** DISCCART: DISCRETE, BASED ON POLAR, 72 DIR, 5 DEG INTERVALS, 400- 2000 M, 100 SPACING

** (400 M = MINIMUM DISTANCE TO PLANT BOUNDARY)

** UPOL1: POLAR, 36 DIR, 10 DEG INTERVALS, 2250-7000 M, 250 M SPACING

** (2250 M = APPROX. MAX. DISTANCE TO BOUNDARY)

** UPOL2: POLAR, 36 DIR, 10 DEG INTERVALS, 7500- 15000 M, 500 M SPACING

**

RE STARTING

GRIDPOLR UPOL1 STA

ORIG 0.00 0.00

DIST 2250 2500 2750 3000 3250 3500 3750 4000 4250 4500 4750

DIST 5000 5250 5500 5750 6000 6250 6500 6750 7000

GDIR 36 0.00 10.00

GRIDPOLR UPOL1 END

GRIDPOLR UPOL2 STA

ORIG 0.00 0.00

DIST 7500 8000 8500 9000 9500 10000 10500 11000 11500 12000

DIST 12500 13000 13500 14000 14500 15000

GDIR 36 1.00 10.00

GRIDPOLR UPOL2 END

DISCCART 0.00 900.00

DISCCART 0.00 1000.00

DISCCART 0.00 1100.00


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**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey3.INP
**
*****
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**
*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
TITLEONE 1987 FPL TURKEY PT 4 CTS OIL CC- 50% LOAD 95F- PM COOLING TWR 10/28/03
TITLETWO SIG IMPACT ANALYSIS TWR:0.001% DRIFT 2.35 LB/HR
MODELOPT DFAULT CONC RURAL
AVERTIME PERIOD 24
POLLUTID GEN
TERRHGT5 FLAT
RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (O= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord.      Y Coord. **
LOCATION OCA5095    POINT  0.000      0.000
LOCATION OCB5095    POINT  42.450      0.000
LOCATION OCC5095    POINT  127.960     0.000
LOCATION OCD5095    POINT  170.720     0.000

LOCATION CELL01 POINT  42.870  62.390
LOCATION CELL02 POINT  61.040  62.390
LOCATION CELL03 POINT  79.620  62.390
LOCATION CELL04 POINT  97.780  62.390
LOCATION CELL05 POINT  115.950  62.390
LOCATION CELL06 POINT  134.390  62.390
LOCATION CELL07 POINT  152.270  62.390
LOCATION CELL08 POINT  171.140  62.390
LOCATION CELL09 POINT  189.300  61.390
LOCATION CELL10 POINT  207.050  61.390
LOCATION CELL11 POINT  225.630  62.390
LOCATION CELL12 POINT  42.870  43.810
LOCATION CELL13 POINT  61.040  43.810
LOCATION CELL14 POINT  79.620  43.810
LOCATION CELL15 POINT  97.780  43.810
LOCATION CELL16 POINT  115.950  43.810
LOCATION CELL17 POINT  134.390  43.810
LOCATION CELL18 POINT  152.270  43.810
LOCATION CELL19 POINT  171.140  43.810
LOCATION CELL20 POINT  189.300  43.810
LOCATION CELL21 POINT  207.050  43.810
LOCATION CELL22 POINT  225.630  43.810

** Source Parameters **
** POINT:  SRCID      QS      HS      TS      VS      DS
** VOLUME:  SRCID      QS      HS      SYINIT  SZINIT
** AREA:    SRCID      QS      RH      XINIT   YINIT
** UNITS:    (g/s)      (m)      (K)      (m/s)      (m)
SRCPARAM OCA5095      2.19      39.900      404.0      13.000      5.790
SRCPARAM OCB5095      2.19      39.900      404.0      13.000      5.790
SRCPARAM OCC5095      2.19      39.900      404.0      13.000      5.790

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SRCPARAM	CELL01	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL02	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL03	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL04	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL05	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL06	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL07	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL08	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL09	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL10	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL11	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL12	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL13	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL14	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL15	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL16	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL17	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL18	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL19	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL20	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL21	0.0135	19.800	309.0	6.72	11.60
SRCPARAM	CELL22	0.0135	19.800	309.0	6.72	11.60

[illegible]

BUILDWID	OCA5095	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	OCA5095	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCA5095	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	OCA5095	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	OCA5095	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCA5095	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	OCB5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCB5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCB5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCB5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCB5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCB5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCC5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCC5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCC5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCC5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCC5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCC5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCD5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCD5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCD5095	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCD5095	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCD5095	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCD5095	31.00	28.65	25.42	21.41	16.76	11.60

Page: 2

Page: 3

BUILDHGT	CELL16	15.50	15.50	29.60	15.50	15.50	15.50
BUILDHGT	CELL16	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL16	15.50	15.50	15.50	15.50	15.50	29.60
BUILDHGT	CELL16	29.60	29.60	29.60	29.60	29.60	15.50
BUILDHGT	CELL17	29.60	29.60	15.50	15.50	29.60	29.60
BUILDHGT	CELL17	29.60	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL17	29.60	29.60	29.60	29.60	15.50	29.60
BUILDHGT	CELL18	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	CELL18	29.60	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL18	15.50	29.60	29.60	15.50	15.50	15.50
BUILDHGT	CELL18	15.50	15.50	29.60	29.60	15.50	15.50
BUILDHGT	CELL18	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL18	15.50	29.60	29.60	29.60	29.60	15.50
BUILDHGT	CELL19	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	CELL19	29.60	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	29.60	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL19	15.50	15.50	15.50	15.50	29.60	29.60
BUILDHGT	CELL20	29.60	29.60	29.60	29.60	29.60	29.60
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	29.60	29.60	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL20	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	29.60	29.60	29.60	29.60	29.60
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
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BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL21	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	29.60	29.60	29.60	29.60
BUILDHGT	CELL22	29.60	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
BUILDHGT	CELL22	15.50	15.50	15.50	15.50	15.50	15.50
BUILDWID	CELL01	16.76	21.51	25.55	28.82	157.03	132.08
BUILDWID	CELL01	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL01	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL01	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL01	103.11	71.01	36.75	71.01	103.11	32.42
BUILDWID	CELL01	31.00	28.65	192.01	200.98	16.76	11.60
BUILDWID	CELL02	16.76	21.41	25.55	28.82	31.21	132.08
BUILDWID	CELL02	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL02	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL02	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL02	103.11	71.01	36.75	71.01	103.11	32.42
BUILDWID	CELL02	31.00	28.65	25.42	200.98	203.84	200.50
BUILDWID	CELL03	203.84	21.41	25.42	28.65	31.21	132.08
BUILDWID	CELL03	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL03	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL03	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL03	103.11	71.01	36.75	71.01	103.11	32.42
BUILDWID	CELL03	31.00	28.65	25.42	21.41	203.84	200.50
BUILDWID	CELL04	203.84	200.98	25.42	28.65	31.00	32.66
BUILDWID	CELL04	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL04	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL04	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL04	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL04	31.00	28.65	25.42	21.41	16.76	200.50
BUILDWID	CELL05	203.84	200.98	25.42	28.65	31.00	32.66
BUILDWID	CELL05	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL05	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL05	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL05	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL05	31.00	28.65	25.42	21.41	16.76	200.50
BUILDWID	CELL06	16.76	200.98	192.01	28.65	31.00	32.42
BUILDWID	CELL06	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL06	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL06	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL06	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL06	157.03	28.65	25.42	21.41	203.84	11.60
BUILDWID	CELL07	16.76	21.41	25.42	177.21	31.00	32.42
BUILDWID	CELL07	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL07	157.03	177.21	192.01	200.98	203.84	200.50
BUILDWID	CELL07	203.84	200.98	192.01	177.21	157.03	132.08
BUILDWID	CELL07	103.11	71.01	36.75	71.01	103.11	132.08
BUILDWID	CELL07	157.03	177.21	25.42	21.41	16.76	200.50
BUILDWID	CELL08	16.76	21.41	25.42	28.65	157.03	132.08

BUILDWID CELL08 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL08 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL08 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL08 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL08 157.03 177.21 192.01 200.98 16.76 11.60
BUILDWID CELL09 16.76 21.41 25.42 28.65 31.00 132.08
BUILDWID CELL09 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL09 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL09 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL09 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL09 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL10 203.84 21.41 25.42 28.65 31.00 132.08
BUILDWID CELL10 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL10 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL10 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL10 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL10 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL11 203.84 200.98 25.42 28.65 31.00 32.42
BUILDWID CELL11 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL11 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL11 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL11 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL11 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL12 16.76 21.51 25.55 28.82 31.21 132.08
BUILDWID CELL12 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL12 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL12 203.84 21.41 192.01 177.21 157.03 132.08
BUILDWID CELL12 103.11 71.01 36.75 71.01 32.85 32.42
BUILDWID CELL12 31.00 28.65 192.01 200.98 16.76 11.60
BUILDWID CELL13 16.76 21.41 25.55 28.65 31.21 32.66
BUILDWID CELL13 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL13 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL13 203.84 200.98 25.42 28.65 157.03 132.08
BUILDWID CELL13 103.11 71.01 36.75 71.01 32.85 32.42
BUILDWID CELL13 31.00 28.65 192.01 200.98 203.84 200.50
BUILDWID CELL14 203.84 21.41 25.42 28.65 31.00 32.66
BUILDWID CELL14 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL14 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL14 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL14 103.11 71.01 36.75 71.01 32.85 32.42
BUILDWID CELL14 31.00 28.65 25.42 200.98 203.84 200.50
BUILDWID CELL15 203.84 200.98 25.42 28.65 31.00 32.42
BUILDWID CELL15 33.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL15 31.00 28.65 192.01 200.98 203.84 200.50
BUILDWID CELL15 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL15 103.11 71.01 36.75 71.01 103.11 32.42
BUILDWID CELL15 31.00 28.65 25.42 21.41 203.84 200.50
BUILDWID CELL16 203.84 200.98 192.01 28.65 31.00 32.42
BUILDWID CELL16 33.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL16 157.03 177.21 25.42 200.98 203.84 200.50
BUILDWID CELL16 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL16 103.11 71.01 36.75 71.01 103.11 32.42
BUILDWID CELL16 31.00 28.65 25.42 21.41 16.76 200.50
BUILDWID CELL17 16.76 21.41 192.01 177.21 31.00 32.42
BUILDWID CELL17 32.85 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL17 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL17 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL17 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL17 31.00 28.65 25.42 21.41 203.84 11.60
BUILDWID CELL18 16.76 21.41 25.42 28.65 31.00 32.42
BUILDWID CELL18 32.85 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL18 157.03 28.65 25.42 200.98 203.84 200.50
BUILDWID CELL18 203.84 200.98 25.42 28.65 157.03 132.08
BUILDWID CELL18 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL18 157.03 28.65 25.42 21.41 16.76 200.50
BUILDWID CELL19 16.76 21.41 25.42 28.65 31.00 32.42
BUILDWID CELL19 32.85 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL19 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL19 203.84 21.41 192.01 177.21 157.03 132.08
BUILDWID CELL19 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL19 157.03 177.21 192.01 200.98 16.76 11.60
BUILDWID CELL20 16.76 21.41 25.42 28.65 31.00 32.42
BUILDWID CELL20 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL20 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL20 203.84 200.98 25.42 28.65 157.03 132.08
BUILDWID CELL20 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL20 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL21 203.84 21.41 25.42 28.65 31.00 32.42
BUILDWID CELL21 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL21 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL21 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL21 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL21 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL22 203.84 200.98 25.42 28.65 31.00 32.42

BUILDWID CELL22 32.85 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL22 157.03 177.21 192.01 200.98 203.84 200.50
BUILDWID CELL22 203.84 200.98 192.01 177.21 157.03 132.08
BUILDWID CELL22 103.11 71.01 36.75 71.01 103.11 132.08
BUILDWID CELL22 157.03 177.21 192.01 200.98 203.84 200.50

SRCGROUP OC5095 OCA5095 OCB5095 OCC5095 OCD5095
SRCGROUP COOLTW CELL01-CELL22
SRCGROUP ALL

SO FINISHED

**

** ISCST3 Receptor Pathway

**

** GRID CENTERED ON HRSG STACK A- WESTERN MOST STACK

**

** DISCCART: DISCRETE, PLANT PROPERTY BOUNDARY, 50 M SPACING

** DISCCART: DISCRETE, BASED ON POLAR, 72 DIR, 5 DEG INTERVALS, 400- 2000 M, 100 SPACING

** (400 M = MINIMUM DISTANCE TO PLANT BOUNDARY)

** UPOL1: POLAR, 36 DIR, 10 DEG INTERVALS, 2250-7000 M, 250 M SPACING

** (2250 M = APPROX. MAX. DISTANCE TO BOUNDARY)

** UPOL2: POLAR, 36 DIR, 10 DEG INTERVALS, 7500- 15000 M, 500 M SPACING

**

RE STARTING

GRIDPOLR UPOL1 STA

ORIG 0.00 0.00

DIST 2250 2500 2750 3000 3250 3500 3750 4000 4250 4500 4750

DIST 5000 5250 5500 5750 6000 6250 6500 6750 7000

GDIR 36 0.00 10.00

GRIDPOLR UPOL1 END

GRIDPOLR UPOL2 STA

ORIG 0.00 0.00

DIST 7500 8000 8500 9000 9500 10000 10500 11000 11500 12000

DIST 12500 13000 13500 14000 14500 15000

GDIR 36 1.00 10.00

GRIDPOLR UPOL2 END

DISCCART 0.00 900.00

DISCCART 0.00 1000.00

ISCB03R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :C1GENGCC.087

ISCST3 OUTPUT FILE NUMBER 2 :C1GENGCC.088

ISCST3 OUTPUT FILE NUMBER 3 :C1GENGCC.089

ISCST3 OUTPUT FILE NUMBER 4 :C1GENGCC.090

ISCST3 OUTPUT FILE NUMBER 5 :C1GENGCC.091

First title for last output file is: 1987 FPL TURKEY POINT 4 CTS GAS CC GEN. EMIS. 10 G/S ENP CLASS I 11/05/03

Second title for last output file is: SIG IMPACT ANALYSIS PSD CLASS I

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)

SOURCE GROUP ID: GC1035					
Annual					
	1987	0.05573	541300.0	2814000.0	87123124
	1988	0.05194	542700.0	2816000.0	88123124
	1989	0.05064	542700.0	2816000.0	89123124
	1990	0.05488	542700.0	2816000.0	90123124
	1991	0.04612	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.54642	541300.0	2814000.0	87061024
	1988	0.45588	542000.0	2811000.0	88102724
	1989	0.49636	541300.0	2814000.0	89050324
	1990	0.57365	545700.0	2832200.0	90010524
	1991	0.49710	541300.0	2814000.0	91041324
HIGH 8-Hour					
	1987	1.14355	542700.0	2816000.0	87022024
	1988	0.93067	548000.0	2796500.0	88061508
	1989	1.14872	541300.0	2814000.0	89050308
	1990	1.09243	544100.0	2820000.0	90071624
	1991	1.05949	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.77168	542700.0	2816000.0	87041324
	1988	1.77083	550300.0	2839000.0	88100306
	1989	2.22906	541300.0	2814000.0	89050303
	1990	2.50533	542700.0	2810000.0	90092121
	1991	2.52086	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	4.21033	548600.0	2837500.0	87122809
	1988	4.76658	553000.0	2796500.0	88052406
	1989	3.90981	542000.0	2811000.0	89100818
	1990	4.90951	556600.0	2792000.0	90091819
	1991	4.51350	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC1059					
Annual					
	1987	0.05706	541300.0	2814000.0	87123124
	1988	0.05278	542700.0	2816000.0	88123124
	1989	0.05160	542700.0	2816000.0	89123124
	1990	0.05620	542700.0	2816000.0	90123124
	1991	0.04717	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.56194	541300.0	2814000.0	87061024
	1988	0.46155	542000.0	2811000.0	88102724
	1989	0.51048	541300.0	2814000.0	89050324
	1990	0.58160	545700.0	2832200.0	90010524
	1991	0.50559	541300.0	2814000.0	91050124
HIGH 8-Hour					
	1987	1.16042	542700.0	2816000.0	87022024
	1988	0.94020	548000.0	2796500.0	88061508
	1989	1.18434	541300.0	2814000.0	89050308
	1990	1.11822	544100.0	2820000.0	90071624
	1991	1.08723	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.79403	542700.0	2816000.0	87041324
	1988	1.80771	550300.0	2839000.0	88100306
	1989	2.29648	541300.0	2814000.0	89050303
	1990	2.55683	542700.0	2810000.0	90092121
	1991	2.61503	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	4.31090	548600.0	2837500.0	87122809
	1988	4.90217	553000.0	2796500.0	88052406
	1989	3.99536	542000.0	2811000.0	89100818
	1990	5.04036	556600.0	2792000.0	90091819
	1991	4.64534	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC1095					
Annual					
	1987	0.05856	541300.0	2814000.0	87123124
	1988	0.05382	542700.0	2816000.0	88123124
	1989	0.05300	542700.0	2816000.0	89123124
	1990	0.05790	542700.0	2816000.0	90123124
	1991	0.04827	542700.0	2816000.0	91123124
HIGH 24-Hour					

	1987	0.57411	541300.0	2814000.0	87061024
	1988	0.46943	542000.0	2811000.0	88102724
	1989	0.53087	541300.0	2814000.0	89050324
	1990	0.59281	545700.0	2832200.0	90010524
	1991	0.51894	541300.0	2814000.0	91050124
HIGH 8-Hour					
	1987	1.18405	542700.0	2816000.0	87022024
	1988	0.95342	548000.0	2796500.0	88061508
	1989	1.23608	541300.0	2814000.0	89050308
	1990	1.15491	544100.0	2820000.0	90071624
	1991	1.12697	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.82563	542700.0	2816000.0	87041324
	1988	1.91657	550300.0	2839000.0	88100306
	1989	2.39417	541300.0	2814000.0	89050303
	1990	2.62873	542700.0	2810000.0	90092121
	1991	2.75294	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	4.45462	548600.0	2837500.0	87122809
	1988	5.09735	553000.0	2796500.0	88052406
	1989	4.11644	542000.0	2811000.0	89100818
	1990	5.22503	556600.0	2792000.0	90091819
	1991	4.83262	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC7535					
Annual					
	1987	0.06135	541300.0	2814000.0	87123124
	1988	0.05676	542700.0	2816000.0	88123124
	1989	0.05582	542700.0	2816000.0	89123124
	1990	0.06157	542700.0	2816000.0	90123124
	1991	0.05105	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.60312	541300.0	2814000.0	87061024
	1988	0.48678	542000.0	2811000.0	88102724
	1989	0.60669	541300.0	2814000.0	89050324
	1990	0.61790	545700.0	2832200.0	90010524
	1991	0.55691	541300.0	2814000.0	91050124
HIGH 8-Hour					
	1987	1.23572	542700.0	2816000.0	87022024
	1988	0.98205	548000.0	2796500.0	88061508
	1989	1.44247	541300.0	2814000.0	89050308
	1990	1.24302	544100.0	2820000.0	90020908
	1991	1.22125	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.96505	556000.0	2796000.0	87010821
	1988	2.03828	550300.0	2839000.0	88100306
	1989	2.85082	541300.0	2814000.0	89050303
	1990	2.79757	542700.0	2810000.0	90092121
	1991	3.08151	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	4.78340	548600.0	2837500.0	87122809
	1988	5.54998	553000.0	2796500.0	88052406
	1989	4.39551	542000.0	2811000.0	89100818
	1990	5.66473	556600.0	2792000.0	90091819
	1991	5.28002	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC7559					
Annual					
	1987	0.06155	541300.0	2814000.0	87123124
	1988	0.05687	542700.0	2816000.0	88123124
	1989	0.05593	542700.0	2816000.0	89123124
	1990	0.06173	542700.0	2816000.0	90123124
	1991	0.05117	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.60441	541300.0	2814000.0	87061024
	1988	0.48761	542000.0	2811000.0	88102724
	1989	0.60915	541300.0	2814000.0	89050324
	1990	0.61917	545700.0	2832200.0	90010524
	1991	0.55835	541300.0	2814000.0	91050124
HIGH 8-Hour					
	1987	1.23827	542700.0	2816000.0	87022024
	1988	0.98343	548000.0	2796500.0	88061508
	1989	1.44888	541300.0	2814000.0	89050308
	1990	1.24624	544100.0	2820000.0	90020908
	1991	1.22565	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	2.05783	556000.0	2796000.0	87010821
	1988	2.04406	550300.0	2839000.0	88100306
	1989	2.86280	541300.0	2814000.0	89050303
	1990	2.80444	542700.0	2810000.0	90092121
	1991	3.09870	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	4.79982	548600.0	2837500.0	87122809
	1988	5.57279	553000.0	2796500.0	88052406
	1989	4.40846	542000.0	2811000.0	89100818
	1990	5.68317	556600.0	2792000.0	90091819

SOURCE GROUP ID:	1991	5.29940	556000.0	2796000.0	91091308
Annual	1987	0.06263	541300.0	2814000.0	87123124
	1988	0.05768	542700.0	2816000.0	88123124
	1989	0.05678	542700.0	2816000.0	89123124
	1990	0.06310	542700.0	2816000.0	90123124
	1991	0.05224	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.61482	541300.0	2814000.0	87061024
	1988	0.49358	542000.0	2811000.0	88102724
	1989	0.62697	541300.0	2814000.0	89050324
	1990	0.62779	545700.0	2832200.0	90010524
	1991	0.56965	541300.0	2814000.0	91050124
HIGH 8-Hour	1987	1.25597	542700.0	2816000.0	87022024
	1988	0.99322	548000.0	2796500.0	88061508
	1989	1.49420	541300.0	2814000.0	89050308
	1990	1.27567	544100.0	2820000.0	90071624
	1991	1.25987	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	2.11315	556000.0	2796000.0	87010821
	1988	2.08698	550300.0	2839000.0	88100306
	1989	2.94826	541300.0	2814000.0	89050303
	1990	2.86262	542700.0	2810000.0	90092121
	1991	3.22305	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	4.91859	548600.0	2837500.0	87122809
	1988	5.73850	553000.0	2796500.0	88052406
	1989	4.50733	542000.0	2811000.0	89100818
	1990	5.83774	556600.0	2792000.0	90091819
	1991	5.45865	556000.0	2796000.0	91091308
SOURCE GROUP ID:	GC5035				
Annual	1987	0.06726	541300.0	2814000.0	87123124
	1988	0.06188	542700.0	2816000.0	88123124
	1989	0.06105	542700.0	2816000.0	89123124
	1990	0.06887	542700.0	2816000.0	90123124
	1991	0.05687	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.65956	541300.0	2814000.0	87061024
	1988	0.58461	542700.0	2816000.0	88020124
	1989	0.72186	541300.0	2814000.0	89050324
	1990	0.66579	545700.0	2832200.0	90010524
	1991	0.63656	553000.0	2796500.0	91102724
HIGH 8-Hour	1987	1.33463	542700.0	2816000.0	87022024
	1988	1.41042	542700.0	2816000.0	88020108
	1989	1.74726	541300.0	2814000.0	89050308
	1990	1.47998	544100.0	2820000.0	90090724
	1991	1.48817	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	2.37072	556000.0	2796000.0	87010821
	1988	2.34083	545700.0	2832200.0	88082603
	1989	3.35290	541300.0	2814000.0	89050303
	1990	3.14949	542700.0	2810000.0	90092121
	1991	3.96844	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	5.47363	548600.0	2837500.0	87122809
	1988	6.52692	553000.0	2796500.0	88052406
	1989	4.97746	542000.0	2811000.0	89100818
	1990	6.61258	556600.0	2792000.0	90091819
	1991	6.25877	556000.0	2796000.0	91091308
SOURCE GROUP ID:	GC5059				
Annual	1987	0.06730	541300.0	2814000.0	87123124
	1988	0.06192	542700.0	2816000.0	88123124
	1989	0.06108	542700.0	2816000.0	89123124
	1990	0.06892	542700.0	2816000.0	90123124
	1991	0.05691	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.65978	541300.0	2814000.0	87061024
	1988	0.58526	542700.0	2816000.0	88020124
	1989	0.72252	541300.0	2814000.0	89050324
	1990	0.66616	545700.0	2832200.0	90010524
	1991	0.63731	553000.0	2796500.0	91102724
HIGH 8-Hour	1987	1.33527	542700.0	2816000.0	87022024
	1988	1.41213	542700.0	2816000.0	88020108
	1989	1.74909	541300.0	2814000.0	89050308
	1990	1.48109	544100.0	2820000.0	90090724
	1991	1.49001	553000.0	2796500.0	91102724
HIGH 3-Hour	1987	2.37393	556000.0	2796000.0	87010821

	1988	2.34210	545700.0	2832200.0	88082603
	1989	3.35614	541300.0	2814000.0	89050303
	1990	3.14975	542700.0	2810000.0	90092121
	1991	3.97335	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	5.47753	548600.0	2837500.0	87122809
	1988	6.53254	553000.0	2796500.0	88052406
	1989	4.97966	542000.0	2811000.0	89100818
	1990	6.61371	556600.0	2792000.0	90091819
	1991	6.26056	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC5095					
Annual					
	1987	0.06695	541300.0	2814000.0	87123124
	1988	0.06196	542700.0	2816000.0	88123124
	1989	0.06110	542700.0	2816000.0	89123124
	1990	0.06893	542700.0	2816000.0	90123124
	1991	0.05693	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.65956	541300.0	2814000.0	87061024
	1988	0.58658	542700.0	2816000.0	88020124
	1989	0.72265	541300.0	2814000.0	89050324
	1990	0.66649	545700.0	2832200.0	90010524
	1991	0.63741	553000.0	2796500.0	91102724
HIGH 8-Hour					
	1987	1.33584	542700.0	2816000.0	87022024
	1988	1.41573	542700.0	2816000.0	88020108
	1989	1.74962	541300.0	2814000.0	89050308
	1990	1.47866	544100.0	2820000.0	90090724
	1991	1.49011	553000.0	2796500.0	91102724
HIGH 3-Hour					
	1987	2.37758	556000.0	2796000.0	87010821
	1988	2.33897	545700.0	2832200.0	88082603
	1989	3.35663	541300.0	2814000.0	89050303
	1990	3.14484	542700.0	2810000.0	90092121
	1991	3.97362	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	5.47695	548600.0	2837500.0	87122809
	1988	6.53170	553000.0	2796500.0	88052406
	1989	4.97630	542000.0	2811000.0	89100818
	1990	6.60131	556600.0	2792000.0	90091819
	1991	6.24928	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC1035					
Annual					
	1987	0.05310	541300.0	2814000.0	87123124
	1988	0.04963	542700.0	2816000.0	88123124
	1989	0.04804	542700.0	2816000.0	89123124
	1990	0.05175	542700.0	2816000.0	90123124
	1991	0.04333	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.51772	541300.0	2814000.0	87061024
	1988	0.43879	542000.0	2811000.0	88102724
	1989	0.46377	545700.0	2832200.0	89091524
	1990	0.55020	545700.0	2832200.0	90010524
	1991	0.47711	541300.0	2814000.0	91041324
HIGH 8-Hour					
	1987	1.09370	542700.0	2816000.0	87022024
	1988	0.90209	548000.0	2796500.0	88061508
	1989	1.05000	541300.0	2814000.0	89050308
	1990	1.01647	544100.0	2820000.0	90071624
	1991	0.97887	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.70729	542700.0	2816000.0	87041324
	1988	1.66359	550300.0	2839000.0	88100306
	1989	2.04089	541300.0	2814000.0	89050303
	1990	2.34583	542700.0	2810000.0	90092121
	1991	2.26208	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	3.92180	548600.0	2837500.0	87122809
	1988	4.38218	553000.0	2796500.0	88052406
	1989	3.65668	542000.0	2811000.0	89100818
	1990	4.51287	556600.0	2792000.0	90091819
	1991	4.11992	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC1059					
Annual					
	1987	0.05409	541300.0	2814000.0	87123124
	1988	0.05043	542700.0	2816000.0	88123124
	1989	0.04907	542700.0	2816000.0	89123124
	1990	0.05281	542700.0	2816000.0	90123124
	1991	0.04421	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.53209	541300.0	2814000.0	87061024
	1988	0.44390	542000.0	2811000.0	88102724
	1989	0.46918	545700.0	2832200.0	89091524
	1990	0.55776	545700.0	2832200.0	90010524

	1991	0.48320	541300.0	2814000.0	91041324
HIGH 8-Hour	1987	1.10877	542700.0	2816000.0	87022024
	1988	0.91074	548000.0	2796500.0	88061508
	1989	1.07925	541300.0	2814000.0	89050308
	1990	1.03809	544100.0	2820000.0	90071624
	1991	1.00171	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	1.72699	542700.0	2816000.0	87041324
	1988	1.69485	550300.0	2839000.0	88100306
	1989	2.09640	541300.0	2814000.0	89050303
	1990	2.38991	542700.0	2810000.0	90092121
	1991	2.33741	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	4.00691	548600.0	2837500.0	87122809
	1988	4.49485	553000.0	2796500.0	88052406
	1989	3.72960	542000.0	2811000.0	89100818
	1990	4.62218	556600.0	2792000.0	90091819
	1991	4.22891	556000.0	2796000.0	91091308
SOURCE GROUP ID: GC1095					
Annual	1987	0.05517	541300.0	2814000.0	87123124
	1988	0.05142	542700.0	2816000.0	88123124
	1989	0.05019	542700.0	2816000.0	89123124
	1990	0.05420	542700.0	2816000.0	90123124
	1991	0.04549	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.54393	541300.0	2814000.0	87061024
	1988	0.45140	542000.0	2811000.0	88102724
	1989	0.48623	541300.0	2814000.0	89050324
	1990	0.56817	545700.0	2832200.0	90010524
	1991	0.49219	541300.0	2814000.0	91041324
HIGH 8-Hour	1987	1.13104	542700.0	2816000.0	87022024
	1988	0.92344	548000.0	2796500.0	88061508
	1989	1.12379	541300.0	2814000.0	89050308
	1990	1.07075	544100.0	2820000.0	90071624
	1991	1.03644	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	1.75621	542700.0	2816000.0	87041324
	1988	1.79797	550300.0	2839000.0	88100306
	1989	2.18086	541300.0	2814000.0	89050303
	1990	2.45603	542700.0	2810000.0	90092121
	1991	2.45323	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	4.13509	548600.0	2837500.0	87122809
	1988	4.66568	553000.0	2796500.0	88052406
	1989	3.83912	542000.0	2811000.0	89100818
	1990	4.78751	556600.0	2792000.0	90091819
	1991	4.39436	556000.0	2796000.0	91091308
All receptor computations reported with respect to a user-specified origin					
GRID	0.00	0.00			
DISCRETE	0.00	0.00			

ISCB03R REL

ISCST3 OUTPUT FILE NUMBER 1 :C1GENGPA.087
 ISCST3 OUTPUT FILE NUMBER 2 :C1GENGPA.088
 ISCST3 OUTPUT FILE NUMBER 3 :C1GENGPA.089
 ISCST3 OUTPUT FILE NUMBER 4 :C1GENGPA.090
 ISCST3 OUTPUT FILE NUMBER 5 :C1GENGPA.091

First title for last output file is: 1987 FPL TURKEY PT 4 CTS GAS CC GEN. EMIS. 10 G/S ENP CLASS I PWR AUG 11/05/
 Second title for last output file is: SIG IMPACT ANALYSIS PSD CLASS I

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)

SOURCE GROUP ID: GCPA80					
Annual	1987	0.05881	541300.0	2814000.0	87123124
	1988	0.05403	542700.0	2816000.0	88123124
	1989	0.05318	542700.0	2816000.0	89123124
	1990	0.05817	542700.0	2816000.0	90123124
	1991	0.04847	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.57685	541300.0	2814000.0	87061024
	1988	0.47111	542000.0	2811000.0	88102724
	1989	0.53517	541300.0	2814000.0	89050324
	1990	0.59509	545700.0	2832200.0	90010524
	1991	0.52172	541300.0	2814000.0	91050124
HIGH 8-Hour	1987	1.18844	542700.0	2816000.0	87022024
	1988	0.95617	548000.0	2796500.0	88061508
	1989	1.24696	541300.0	2814000.0	89050308
	1990	1.16312	544100.0	2820000.0	90071624
	1991	1.13589	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	1.83090	542700.0	2816000.0	87041324
	1988	1.92795	550300.0	2839000.0	88100306
	1989	2.41483	541300.0	2814000.0	89050303
	1990	2.64560	542700.0	2810000.0	90092121
	1991	2.78250	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	4.48520	548600.0	2837500.0	87122809
	1988	5.13909	553000.0	2796500.0	88052406
	1989	4.14315	542000.0	2811000.0	89100818
	1990	5.26826	556600.0	2792000.0	90091819
	1991	4.87604	556000.0	2796000.0	91091308
All receptor computations reported with respect to a user-specified origin					
GRID	0.00	0.00			
DISCRETE	0.00	0.00			

ISCB03R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :C1GENOCC.087
 ISCST3 OUTPUT FILE NUMBER 2 :C1GENOCC.088
 ISCST3 OUTPUT FILE NUMBER 3 :C1GENOCC.089
 ISCST3 OUTPUT FILE NUMBER 4 :C1GENOCC.090
 ISCST3 OUTPUT FILE NUMBER 5 :C1GENOCC.091

First title for last output file is: 1987 FPL TURKEY POINT 4 CTS OIL CC GEN. EMIS. 10 G/S ENP CLASS I 11/05/03
 Second title for last output file is: SIG IMPACT ANALYSIS PSD CLASS I

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: OC1035					
Annual	1987	0.03959	541300.0	2814000.0	87123124
	1988	0.03736	542700.0	2816000.0	88123124
	1989	0.03594	542700.0	2816000.0	89123124
	1990	0.03740	542700.0	2816000.0	90123124
	1991	0.03168	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.38338	542000.0	2811000.0	87051624
	1988	0.34872	542000.0	2811000.0	88102724
	1989	0.37201	545700.0	2832200.0	89091524
	1990	0.43528	545700.0	2832200.0	90010524
	1991	0.37339	541300.0	2814000.0	91041324
HIGH 8-Hour	1987	0.83557	542700.0	2816000.0	87022024
	1988	0.69057	542700.0	2816000.0	88020108
	1989	0.77419	541300.0	2814000.0	89032808
	1990	0.70069	544100.0	2820000.0	90071624
	1991	0.65962	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	1.38353	542700.0	2816000.0	87041324
	1988	1.22376	542700.0	2816000.0	88071724
	1989	1.59011	541300.0	2814000.0	89032806
	1990	1.65771	542700.0	2810000.0	90092121
	1991	1.30640	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	2.68500	548600.0	2837500.0	87122809
	1988	2.81675	553000.0	2796500.0	88052406
	1989	2.56022	542000.0	2811000.0	89100818
	1990	2.91334	556600.0	2792000.0	90091819
	1991	2.65665	545700.0	2832200.0	91072521
SOURCE GROUP ID: OC1059					
Annual	1987	0.04080	541300.0	2814000.0	87123124
	1988	0.03858	542700.0	2816000.0	88123124
	1989	0.03719	542700.0	2816000.0	89123124
	1990	0.03855	542700.0	2816000.0	90123124
	1991	0.03272	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.39424	542000.0	2811000.0	87051624
	1988	0.35883	542000.0	2811000.0	88102724
	1989	0.38020	545700.0	2832200.0	89091524
	1990	0.44595	545700.0	2832200.0	90010524
	1991	0.38469	541300.0	2814000.0	91041324
HIGH 8-Hour	1987	0.86456	542700.0	2816000.0	87022024
	1988	0.70962	542700.0	2816000.0	88020108
	1989	0.79220	541300.0	2814000.0	89032808
	1990	0.72596	544100.0	2820000.0	90071624
	1991	0.68415	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	1.41282	542700.0	2816000.0	87041324
	1988	1.25760	542700.0	2816000.0	88071724
	1989	1.62746	541300.0	2814000.0	89032806
	1990	1.71365	542700.0	2810000.0	90092121
	1991	1.37606	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	2.78674	548600.0	2837500.0	87122809
	1988	2.94017	553000.0	2796500.0	88052406
	1989	2.65061	542000.0	2811000.0	89100818
	1990	3.03638	556600.0	2792000.0	90091819
	1991	2.76038	545700.0	2832200.0	91072521
SOURCE GROUP ID: OC1095					
Annual	1987	0.04303	541300.0	2814000.0	87123124
	1988	0.04035	542700.0	2816000.0	88123124
	1989	0.03899	542700.0	2816000.0	89123124
	1990	0.04058	542700.0	2816000.0	90123124
	1991	0.03455	542700.0	2816000.0	91123124
HIGH 24-Hour					

	1987	0.41403	542000.0	2811000.0	87051624
	1988	0.37387	542000.0	2811000.0	88102724
	1989	0.39629	545700.0	2832200.0	89091524
	1990	0.46538	545700.0	2832200.0	90010524
	1991	0.40201	541300.0	2814000.0	91041324
HIGH 8-Hour					
	1987	0.90773	542700.0	2816000.0	87022024
	1988	0.74082	542700.0	2816000.0	88020108
	1989	0.87946	541300.0	2814000.0	89032808
	1990	0.77045	544100.0	2820000.0	90071624
	1991	0.72782	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.47118	542700.0	2816000.0	87041324
	1988	1.31609	542700.0	2816000.0	88071724
	1989	1.69968	541300.0	2814000.0	89032806
	1990	1.81118	542700.0	2810000.0	90092121
	1991	1.50268	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	2.96587	548600.0	2837500.0	87122809
	1988	3.15990	553000.0	2796500.0	88052406
	1989	2.80888	542000.0	2811000.0	89100818
	1990	3.25423	556600.0	2792000.0	90091819
	1991	2.94314	545700.0	2832200.0	91072521
SOURCE GROUP ID: OC7535					
Annual					
	1987	0.04863	541300.0	2814000.0	87123124
	1988	0.04521	542700.0	2816000.0	88123124
	1989	0.04400	542700.0	2816000.0	89123124
	1990	0.04660	542700.0	2816000.0	90123124
	1991	0.03927	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.47036	542000.0	2811000.0	87051624
	1988	0.40839	542000.0	2811000.0	88102724
	1989	0.43450	545700.0	2832200.0	89091524
	1990	0.51263	545700.0	2832200.0	90010524
	1991	0.44219	541300.0	2814000.0	91041324
HIGH 8-Hour					
	1987	1.00658	542700.0	2816000.0	87022024
	1988	0.85086	548000.0	2796500.0	88061508
	1989	0.96321	541300.0	2814000.0	89032808
	1990	0.89226	544100.0	2820000.0	90071624
	1991	0.85020	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.59717	542700.0	2816000.0	87041324
	1988	1.54101	550300.0	2839000.0	88100306
	1989	1.87751	541300.0	2814000.0	89032806
	1990	2.07468	542700.0	2810000.0	90092121
	1991	1.87062	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	3.45070	548600.0	2837500.0	87122809
	1988	3.76966	553000.0	2796500.0	88052406
	1989	3.23523	542000.0	2811000.0	89100818
	1990	3.86221	556600.0	2792000.0	90091819
	1991	3.48522	556000.0	2796000.0	91091308
SOURCE GROUP ID: OC7559					
Annual					
	1987	0.04899	541300.0	2814000.0	87123124
	1988	0.04554	542700.0	2816000.0	88123124
	1989	0.04433	542700.0	2816000.0	89123124
	1990	0.04699	542700.0	2816000.0	90123124
	1991	0.03959	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.47406	542000.0	2811000.0	87051624
	1988	0.41087	542000.0	2811000.0	88102724
	1989	0.43696	545700.0	2832200.0	89091524
	1990	0.51598	545700.0	2832200.0	90010524
	1991	0.44515	541300.0	2814000.0	91041324
HIGH 8-Hour					
	1987	1.01384	542700.0	2816000.0	87022024
	1988	0.85515	548000.0	2796500.0	88061508
	1989	0.96898	541300.0	2814000.0	89032808
	1990	0.90151	544100.0	2820000.0	90071624
	1991	0.85967	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.60654	542700.0	2816000.0	87041324
	1988	1.55491	550300.0	2839000.0	88100306
	1989	1.88951	541300.0	2814000.0	89032806
	1990	2.09397	542700.0	2810000.0	90092121
	1991	1.90063	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	3.48802	548600.0	2837500.0	87122809
	1988	3.81748	553000.0	2796500.0	88052406
	1989	3.26734	542000.0	2811000.0	89100818
	1990	3.90798	556600.0	2792000.0	90091819

SOURCE GROUP ID:	1991	3.53011	556000.0	2796000.0	91091308
Annual	OC7595				
	1987	0.04969	541300.0	2814000.0	87123124
	1988	0.04617	542700.0	2816000.0	88123124
	1989	0.04520	542700.0	2816000.0	89123124
	1990	0.04783	542700.0	2816000.0	90123124
	1991	0.04045	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.48048	542000.0	2811000.0	87051624
	1988	0.41515	542000.0	2811000.0	88102724
	1989	0.44117	545700.0	2832200.0	89091524
	1990	0.52180	545700.0	2832200.0	90010524
	1991	0.45026	541300.0	2814000.0	91041324
HIGH 8-Hour					
	1987	1.02641	542700.0	2816000.0	87022024
	1988	0.86256	548000.0	2796500.0	88061508
	1989	1.00634	541300.0	2814000.0	89050308
	1990	0.91757	544100.0	2820000.0	90071624
	1991	0.87616	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.62285	542700.0	2816000.0	87041324
	1988	1.58306	550300.0	2839000.0	88100306
	1989	2.01412	541300.0	2814000.0	89050303
	1990	2.12706	542700.0	2810000.0	90092121
	1991	1.95363	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	3.55316	548600.0	2837500.0	87122809
	1988	3.90124	553000.0	2796500.0	88052406
	1989	3.32298	542000.0	2811000.0	89100818
	1990	3.98698	556600.0	2792000.0	90091819
	1991	3.60791	556000.0	2796000.0	91091308
SOURCE GROUP ID:	OC5035				
Annual					
	1987	0.05480	541300.0	2814000.0	87123124
	1988	0.05111	542700.0	2816000.0	88123124
	1989	0.04984	542700.0	2816000.0	89123124
	1990	0.05379	542700.0	2816000.0	90123124
	1991	0.04502	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.53796	541300.0	2814000.0	87061024
	1988	0.44776	542000.0	2811000.0	88102724
	1989	0.50662	541300.0	2814000.0	89050324
	1990	0.56556	545700.0	2832200.0	90010524
	1991	0.49044	541300.0	2814000.0	91050124
HIGH 8-Hour					
	1987	1.12234	542700.0	2816000.0	87022024
	1988	0.91789	548000.0	2796500.0	88061508
	1989	1.18834	541300.0	2814000.0	89050308
	1990	1.05141	544100.0	2820000.0	90071624
	1991	1.01611	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.77544	556000.0	2796000.0	87010821
	1988	1.77701	550300.0	2839000.0	88100306
	1989	2.36437	541300.0	2814000.0	89050303
	1990	2.40604	542700.0	2810000.0	90092121
	1991	2.40421	553000.0	2796500.0	91102721
HIGH 1-Hour					
	1987	4.07770	548600.0	2837500.0	87122809
	1988	4.58902	553000.0	2796500.0	88052406
	1989	3.77747	542000.0	2811000.0	89100818
	1990	4.66678	556600.0	2792000.0	90091819
	1991	4.27984	556000.0	2796000.0	91091308
SOURCE GROUP ID:	OC5059				
Annual					
	1987	0.05480	541300.0	2814000.0	87123124
	1988	0.05111	542700.0	2816000.0	88123124
	1989	0.04983	542700.0	2816000.0	89123124
	1990	0.05378	542700.0	2816000.0	90123124
	1991	0.04502	542700.0	2816000.0	91123124
HIGH 24-Hour					
	1987	0.53782	541300.0	2814000.0	87061024
	1988	0.44771	542000.0	2811000.0	88102724
	1989	0.50660	541300.0	2814000.0	89050324
	1990	0.56558	545700.0	2832200.0	90010524
	1991	0.49035	541300.0	2814000.0	91050124
HIGH 8-Hour					
	1987	1.12229	542700.0	2816000.0	87022024
	1988	0.91785	548000.0	2796500.0	88061508
	1989	1.18832	541300.0	2814000.0	89050308
	1990	1.05106	544100.0	2820000.0	90071624
	1991	1.01575	542000.0	2811000.0	91092324
HIGH 3-Hour					
	1987	1.77606	556000.0	2796000.0	87010821

	1988	1.77671	550300.0	2839000.0	88100306
	1989	2.36424	541300.0	2814000.0	89050303
	1990	2.40479	542700.0	2810000.0	90092121
	1991	2.40396	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	4.07724	548600.0	2837500.0	87122809
	1988	4.58842	553000.0	2796500.0	88052406
	1989	3.77645	542000.0	2811000.0	89100818
	1990	4.66388	556600.0	2792000.0	90091819
	1991	4.27726	556000.0	2796000.0	91091308
SOURCE GROUP ID:	OC5095				
Annual	1987	0.05468	541300.0	2814000.0	87123124
	1988	0.05102	542700.0	2816000.0	88123124
	1989	0.04976	542700.0	2816000.0	89123124
	1990	0.05356	542700.0	2816000.0	90123124
	1991	0.04492	542700.0	2816000.0	91123124
HIGH 24-Hour	1987	0.53639	541300.0	2814000.0	87061024
	1988	0.44693	542000.0	2811000.0	88102724
	1989	0.50487	541300.0	2814000.0	89050324
	1990	0.56470	545700.0	2832200.0	90010524
	1991	0.48905	541300.0	2814000.0	91050124
HIGH 8-Hour	1987	1.12026	542700.0	2816000.0	87022024
	1988	0.91659	548000.0	2796500.0	88061508
	1989	1.18409	541300.0	2814000.0	89050308
	1990	1.04726	544100.0	2820000.0	90071624
	1991	1.01173	542000.0	2811000.0	91092324
HIGH 3-Hour	1987	1.77235	556000.0	2796000.0	87010821
	1988	1.77172	550300.0	2839000.0	88100306
	1989	2.35594	541300.0	2814000.0	89050303
	1990	2.39581	542700.0	2810000.0	90092121
	1991	2.39273	553000.0	2796500.0	91102721
HIGH 1-Hour	1987	4.06442	548600.0	2837500.0	87122809
	1988	4.57132	553000.0	2796500.0	88052406
	1989	3.76402	542000.0	2811000.0	89100818
	1990	4.64201	556600.0	2792000.0	90091819
	1991	4.25612	556000.0	2796000.0	91091308
All receptor computations reported with respect to a user-specified origin					
GRID	0.00	0.00			
DISCRETE	0.00	0.00			


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**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey3.INP
**
*****
**
**
*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
  TITLEONE 1987 FPL TURKEY POINT 4 CTS GAS CC GEN. EMIS. 10 G/S ENP CLASS I 11/05/03
  TITLETWO SIG IMPACT ANALYSIS PSD CLASS I
  MODELOPT DFAULT CONC RURAL
  AVERTIME PERIOD 24 8.3 1
  POLLUTID GEN
  TERRHGT5 FLAT
  RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (0= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord. Y Coord. **
LOCATION GCA5035 POINT 567000 2813500
LOCATION GCB5035 POINT 567000 2813500
LOCATION GCC5035 POINT 567000 2813500
LOCATION GCD5035 POINT 567000 2813500
LOCATION GCA7535 POINT 567000 2813500
LOCATION GCB7535 POINT 567000 2813500
LOCATION GCC7535 POINT 567000 2813500
LOCATION GCD7535 POINT 567000 2813500
LOCATION GCA1035D POINT 567000 2813500
LOCATION GCB1035D POINT 567000 2813500
LOCATION GCC1035D POINT 567000 2813500
LOCATION GCD1035D POINT 567000 2813500
LOCATION GCA1035H POINT 567000 2813500
LOCATION GCB1035H POINT 567000 2813500
LOCATION GCC1035H POINT 567000 2813500
LOCATION GCD1035H POINT 567000 2813500
LOCATION GCA5059 POINT 567000 2813500
LOCATION GCB5059 POINT 567000 2813500
LOCATION GCC5059 POINT 567000 2813500
LOCATION GCD5059 POINT 567000 2813500
LOCATION GCA7559 POINT 567000 2813500
LOCATION GCB7559 POINT 567000 2813500
LOCATION GCC7559 POINT 567000 2813500
LOCATION GCD7559 POINT 567000 2813500
LOCATION GCA1059D POINT 567000 2813500
LOCATION GCB1059D POINT 567000 2813500
LOCATION GCC1059D POINT 567000 2813500
LOCATION GCD1059D POINT 567000 2813500
LOCATION GCA1059H POINT 567000 2813500
LOCATION GCB1059H POINT 567000 2813500
LOCATION GCC1059H POINT 567000 2813500
LOCATION GCD1059H POINT 567000 2813500
LOCATION GCA5095 POINT 567000 2813500
LOCATION GCB5095 POINT 567000 2813500
LOCATION GCC5095 POINT 567000 2813500
LOCATION GCD5095 POINT 567000 2813500

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**** Source Parameters ****

**** Building Downwash ****

Page: 2

SRCGROUP GC1035D GCA1035D GCB1035D GCC1035D GCD1035D
SRCGROUP GC1059D GCA1059D GCB1059D GCC1059D GCD1059D

SRCGROUP GC1095D GCA1095D GCB1095D GCC1095D GCD1095D
SRCGROUP GC7535 GCA7535 GCB7535 GCC7535 GCD7535
SRCGROUP GC7559 GCA7559 GCB7559 GCC7559 GCD7559
SRCGROUP GC7595 GCA7595 GCB7595 GCC7595 GCD7595
SRCGROUP GC5035 GCA5035 GCB5035 GCC5035 GCD5035
SRCGROUP GC5059 GCA5059 GCB5059 GCC5059 GCD5059
SRCGROUP GC5095 GCA5095 GCB5095 GCC5095 GCD5095
SRCGROUP GC1035H GCA1035H GCB1035H GCC1035H GCD1035H
SRCGROUP GC1059H GCA1059H GCB1059H GCC1059H GCD1059H
SRCGROUP GC1095H GCA1095H GCB1095H GCC1095H GCD1095H

SO FINISHED

**

** ISCST3 Receptor Pathway

**

RE STARTING

RE DISCCART	557000.	2789000.
RE DISCCART	556600.	2792000.
RE DISCCART	556000.	2796000.
RE DISCCART	553000.	2796500.
RE DISCCART	548000.	2796500.
RE DISCCART	542700.	2796500.
RE DISCCART	542700.	2800000.
RE DISCCART	542700.	2805000.
RE DISCCART	542700.	2810000.
RE DISCCART	542000.	2811000.
RE DISCCART	541300.	2814000.
RE DISCCART	542700.	2816000.
RE DISCCART	544100.	2820000.
RE DISCCART	543500.	2824600.
RE DISCCART	545000.	2829000.
RE DISCCART	545700.	2832200.
RE DISCCART	546200.	2835700.
RE DISCCART	548600.	2837500.
RE DISCCART	550300.	2839000.
RE DISCCART	545000.	2839000.
RE DISCCART	540000.	2839000.
RE DISCCART	550500.	2844000.
RE DISCCART	545000.	2844000.
RE DISCCART	540000.	2844000.
RE DISCCART	550300.	2848600.
RE DISCCART	549000.	2848600.
RE DISCCART	548000.	2848600.
RE DISCCART	547000.	2848600.
RE DISCCART	546000.	2848600.
RE DISCCART	545000.	2848600.
RE DISCCART	544000.	2848600.
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RE DISCCART	542000.	2848600.
RE DISCCART	541000.	2848600.
RE DISCCART	540000.	2848600.
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RE DISCCART	532000.	2848600.
RE DISCCART	531000.	2848600.
RE DISCCART	530000.	2848600.
RE DISCCART	529000.	2848600.
RE DISCCART	528000.	2848600.
RE DISCCART	527000.	2848600.
RE DISCCART	526000.	2848600.
RE DISCCART	525000.	2848600.
RE DISCCART	524000.	2848600.
RE DISCCART	523000.	2848600.
RE DISCCART	522000.	2848600.
RE DISCCART	521000.	2848600.
RE DISCCART	520000.	2848600.
RE DISCCART	519000.	2848600.
RE DISCCART	518000.	2848600.
RE DISCCART	517000.	2848600.
RE DISCCART	516000.	2848600.
RE DISCCART	515000.	2848600.
RE DISCCART	514500.	2848600.
RE DISCCART	514500.	2848000.
RE DISCCART	514500.	2847600.
RE DISCCART	514500.	2846600.
RE DISCCART	514500.	2845000.
RE DISCCART	514500.	2844000.

RE DISCCART	514500.	2843000.
RE DISCCART	514500.	2842000.
RE DISCCART	514500.	2841000.
RE DISCCART	514500.	2840000.
RE DISCCART	514500.	2839000.
RE DISCCART	514500.	2838000.
RE DISCCART	514500.	2837000.
RE DISCCART	514500.	2836000.
RE DISCCART	514500.	2835000.
RE DISCCART	514500.	2834000.
RE DISCCART	514500.	2833000.
RE DISCCART	514500.	2832500.
RE DISCCART	510000.	2832500.
RE DISCCART	509000.	2832500.
RE DISCCART	508000.	2832500.
RE DISCCART	507000.	2832500.
RE DISCCART	506000.	2832500.
RE DISCCART	505000.	2832500.
RE DISCCART	504000.	2832500.
RE DISCCART	503000.	2832500.
RE DISCCART	502000.	2832500.
RE DISCCART	501000.	2832500.
RE DISCCART	500000.	2832500.
RE DISCCART	499000.	2832500.
RE DISCCART	498000.	2832500.
RE DISCCART	497000.	2832500.
RE DISCCART	496000.	2832500.
RE DISCCART	495000.	2832500.
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RE DISCCART	495000.	2835000.
RE DISCCART	495000.	2836000.
RE DISCCART	494500.	2837000.
RE DISCCART	491500.	2841000.
RE DISCCART	488500.	2845500.
RE DISCCART	483000.	2848500.
RE DISCCART	480000.	2852500.
RE DISCCART	475000.	2854000.
RE DISCCART	473500.	2857000.
RE DISCCART	473000.	2860000.
RE DISCCART	472000.	2860000.
RE DISCCART	471000.	2860000.
RE DISCCART	470000.	2860000.
RE DISCCART	469000.	2860000.
RE DISCCART	468000.	2860000.
RE DISCCART	467000.	2860000.
RE DISCCART	466000.	2860000.
RE DISCCART	465000.	2860000.
RE DISCCART	464000.	2860000.
RE DISCCART	463000.	2860000.
RE DISCCART	462000.	2860000.
RE DISCCART	461000.	2860000.
RE DISCCART	460000.	2860000.
RE DISCCART	459500.	2863200.
RE DISCCART	459000.	2863200.
RE DISCCART	458000.	2863200.
RE DISCCART	457000.	2863200.
RE DISCCART	456000.	2863200.
RE DISCCART	455000.	2863200.
RE DISCCART	454000.	2863200.

RE FINISHED

**

** ISCST3 Meteorology Pathway

**

**

ME STARTING

ME INPUTFIL C:\MET\MIAPBI87.ASC

ME ANEMHGHT 33 FEET

ME SURFDATA 12839 1987 MIAMI

ME UAIRDATA 12844 1987 PALM BEACH INTER

ME WINDCATS 1.54 3.09 5.14 8.23 10.80

ME FINISHED

OU STARTING

OU RECTABLE ALLAVE FIRST

OU FINISHED

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**
*****
**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey3.INP
**
*****
**
**
*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
  TITLEONE 1987 FPL TURKEY PT 4 CTS GAS CC GEN. EMIS. 10 G/S ENP CLASS I PWR AUG 11/05/03
  TITLETWO SIG IMPACT ANALYSIS PSD CLASS I
  MODELOPT DFAULT CONC RURAL
  AVERTIME PERIOD 24 8 3 1
  POLLUTID GEN
  TERRHGTs FLAT
  RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (O= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord.      Y Coord. **
LOCATION GCAPA80      POINT  567000  2813500
LOCATION GCBPA80      POINT  567000  2813500
LOCATION GCCPA80      POINT  567000  2813500
LOCATION GCDPA80      POINT  567000  2813500

** Source Parameters **
** POINT:  SRCID      QS      HS      TS      VS      DS
** VOLUME:  SRCID      QS      HS      SYINIT  SZINIT
** AREA:    SRCID      QS      RH      XINIT   YINIT
** UNITS:    (g/s)      (m)      (K)      (m/s)      (m)
SRCPARAM GCAPA80      2.50      39.900  360.0    16.500  5.790
SRCPARAM GCBPA80      2.50      39.900  360.0    16.500  5.790
SRCPARAM GCCPA80      2.50      39.900  360.0    16.500  5.790
SRCPARAM GCDPA80      2.50      39.900  360.0    16.500  5.790

** Building Downwash **
BUILDHGT GCAPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCAPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCAPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCAPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCAPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCAPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCBPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCBPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCBPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCBPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCBPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCBPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCCPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCCPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCCPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCCPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCCPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCDPA80      26.50 26.50 26.50 26.50 26.50 26.50
BUILDHGT GCDPA80      26.50 26.50 26.50 26.50 26.50 26.50

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BUILDHGT	GCDPA80	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCDPA80	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCDPA80	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	GCDPA80	26.50	26.50	26.50	26.50	26.50	26.50
BUILDWID	GCAPA80	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCAPA80	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCAPA80	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	GCAPA80	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCAPA80	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCAPA80	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	GCBPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCBPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCBPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCBPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCBPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCBPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCCPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCCPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCCPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCCPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCCPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCCPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCDPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCDPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCDPA80	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	GCDPA80	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	GCDPA80	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	GCDPA80	31.00	28.65	25.42	21.41	16.76	11.60

SRCGROUP GCPA80 GCAPA80 GCBPA80 GCCPA80 GCDPA80

SO FINISHED

**

** ISCST3 Receptor Pathway

**

RE STARTING

RE DISCCART	557000.	2789000.
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RE DISCCART	542000.	2811000.
RE DISCCART	541300.	2814000.
RE DISCCART	542700.	2816000.
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RE DISCCART	545000.	2829000.
RE DISCCART	545700.	2832200.
RE DISCCART	546200.	2835700.
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RE DISCCART	462000.	2860000.
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RE DISCCART	457000.	2863200.
RE DISCCART	456000.	2863200.
RE DISCCART	455000.	2863200.
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RE FINISHED

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** ISCST3 Meteorology Pathway
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ME STARTING
ME INPUTFIL C:\MET\MIAPBI87.ASC
ME ANEMHGHT 33 FEET
ME SURFDATA 12839 1987 MIAMI
ME UAIRDATA 12844 1987 PALM_BEACH_INTER
ME WINDCATS 1.54 3.09 5.14 8.23 10.80
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.5
** Lakes Environmental Software Inc.
** Date: 9/19/2003
** File basis: S:\PROJECTS\FPL\turkey\iscset\turkey3.INP
**
*****
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*****
** ISCST3 Control Pathway
*****
**
**
CO STARTING
  TITLEONE 1987 FPL TURKEY POINT 4 CTS OIL CC GEN. EMIS. 10 G/S ENP CLASS I 11/05/03
  TITLETWO SIG IMPACT ANALYSIS PSD CLASS I
  MODELOPT DFAULT CONC RURAL
  AVERTIME PERIOD 24 8 3 1
  POLLUTID GEN
  TERRHGTS FLAT
  RUNORNOT RUN
CO FINISHED
**
*****
** ISCST3 Source Pathway
*****
**
**
SO STARTING
**
** Source ID format
**
** Example: GSA5035
**
**      G= gas (O= oil)
**      S= simple cycle (C= combined cycle)
**      A= unit ID (B, C, D)
**      50= load % (75= 75%, 10= 100%)
**      35= temperature deg F (59, 95)
**      H= high power mode (gas only, SC & CC, 100% load)
**      D= duct burner (gas only, CC only, 100% load)
**
** Source Location **
**      Source ID - Type - X Coord. Y Coord. **
LOCATION OCA5035 POINT 567000 2813500
LOCATION OCB5035 POINT 567000 2813500
LOCATION OCC5035 POINT 567000 2813500
LOCATION OCD5035 POINT 567000 2813500
LOCATION OCA7535 POINT 567000 2813500
LOCATION OCB7535 POINT 567000 2813500
LOCATION OCC7535 POINT 567000 2813500
LOCATION OCD7535 POINT 567000 2813500
LOCATION OCA1035 POINT 567000 2813500
LOCATION OCB1035 POINT 567000 2813500
LOCATION OCC1035 POINT 567000 2813500
LOCATION OCD1035 POINT 567000 2813500
LOCATION OCA5059 POINT 567000 2813500
LOCATION OCB5059 POINT 567000 2813500
LOCATION OCC5059 POINT 567000 2813500
LOCATION OCD5059 POINT 567000 2813500
LOCATION OCA7559 POINT 567000 2813500
LOCATION OCB7559 POINT 567000 2813500
LOCATION OCC7559 POINT 567000 2813500
LOCATION OCD7559 POINT 567000 2813500
LOCATION OCA1059 POINT 567000 2813500
LOCATION OCB1059 POINT 567000 2813500
LOCATION OCC1059 POINT 567000 2813500
LOCATION OCD1059 POINT 567000 2813500
LOCATION OCA5095 POINT 567000 2813500
LOCATION OCB5095 POINT 567000 2813500
LOCATION OCC5095 POINT 567000 2813500
LOCATION OCD5095 POINT 567000 2813500
LOCATION OCA7595 POINT 567000 2813500
LOCATION OCB7595 POINT 567000 2813500
LOCATION OCC7595 POINT 567000 2813500
LOCATION OCD7595 POINT 567000 2813500
LOCATION OCA1095 POINT 567000 2813500
LOCATION OCB1095 POINT 567000 2813500
LOCATION OCC1095 POINT 567000 2813500
LOCATION OCD1095 POINT 567000 2813500

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** Source Parameters **

** POINT:	SRCID	QS	HS	TS	VS	DS
** VOLUME:	SRCID	QS	HS	SYINIT	SZINIT	
** AREA:	SRCID	QS	RH	XINIT	YINIT	
** UNITS:		(g/s)	(m)	(K)	(m/s)	(m)
SRCPARAM	OCA5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCB5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCC5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCD5035	2.50	39.900	397.0	13.600	5.790
SRCPARAM	OCA7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCB7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCC7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCD7535	2.50	39.900	406.0	16.900	5.790
SRCPARAM	OCA1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCB1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCC1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCD1035	2.50	39.900	420.0	22.400	5.790
SRCPARAM	OCA5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCB5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCC5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCD5059	2.50	39.900	399.0	13.400	5.790
SRCPARAM	OCA7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCB7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCC7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCD7559	2.50	39.900	407.0	16.500	5.790
SRCPARAM	OCA1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCB1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCC1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCD1059	2.50	39.900	419.0	21.400	5.790
SRCPARAM	OCA5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCB5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCC5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCD5095	2.50	39.900	404.0	13.000	5.790
SRCPARAM	OCA7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCB7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCC7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCD7595	2.50	39.900	410.0	15.700	5.790
SRCPARAM	OCA1095	2.50	39.900	418.0	19.700	5.790
SRCPARAM	OCB1095	2.50	39.900	418.0	19.700	5.790
SRCPARAM	OCC1095	2.50	39.900	418.0	19.700	5.790
SRCPARAM	OCD1095	2.50	39.900	418.0	19.700	5.790

** Building Downwash **

BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCA1035-OCA7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCB1035-OCB7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCC1035-OCC7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDHGT	OCD1035-OCD7595	26.50	26.50	26.50	26.50	26.50	26.50
BUILDWID	OCA1035-OCA7595	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	OCA1035-OCA7595	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCA1035-OCA7595	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	OCA1035-OCA7595	16.81	21.51	25.55	28.82	31.21	32.66
BUILDWID	OCA1035-OCA7595	33.11	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCA1035-OCA7595	31.00	28.65	25.55	21.51	16.81	11.60
BUILDWID	OCB1035-OCB7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCB1035-OCB7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCB1035-OCB7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCB1035-OCB7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCB1035-OCB7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCB1035-OCB7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCC1035-OCC7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCC1035-OCC7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCC1035-OCC7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCC1035-OCC7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCC1035-OCC7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCC1035-OCC7595	31.00	28.65	25.42	21.41	16.76	11.60

BUILDWID	OCD1035-OCD7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCD1035-OCD7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCD1035-OCD7595	31.00	28.65	25.42	21.41	16.76	11.60
BUILDWID	OCD1035-OCD7595	16.76	21.41	25.42	28.65	31.00	32.42
BUILDWID	OCD1035-OCD7595	32.85	32.29	30.74	32.29	32.85	32.42
BUILDWID	OCD1035-OCD7595	31.00	28.65	25.42	21.41	16.76	11.60

SRCGROUP	OC1035	OCA1035	OCB1035	OCC1035	OCD1035
SRCGROUP	OC1059	OCA1059	OCB1059	OCC1059	OCD1059
SRCGROUP	OC1095	OCA1095	OCB1095	OCC1095	OCD1095
SRCGROUP	OC7535	OCA7535	OCB7535	OCC7535	OCD7535
SRCGROUP	OC7559	OCA7559	OCB7559	OCC7559	OCD7559
SRCGROUP	OC7595	OCA7595	OCB7595	OCC7595	OCD7595
SRCGROUP	OC5035	OCA5035	OCB5035	OCC5035	OCD5035
SRCGROUP	OC5059	OCA5059	OCB5059	OCC5059	OCD5059
SRCGROUP	OC5095	OCA5095	OCB5095	OCC5095	OCD5095

SO FINISHED

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** ISCST3 Receptor Pathway

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RE STARTING

RE DISCCART	557000.	2789000.
RE DISCCART	556600.	2792000.
RE DISCCART	556000.	2796000.
RE DISCCART	553000.	2796500.
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** ISCST3 Meteorology Pathway

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APPENDIX 10.1.6

**FAA NOTICE OF PROPOSED
CONSTRUCTION OR ALTERATION
(Signed Original Sent to FAA)**

U.S. Department of Transportation
Federal Aviation Administration

Failure To Provide All Requested Information May Delay Processing of Your Notice

Notice of Proposed Construction or Alteration

FOR FAA USE ONLY

Aeronautical Study Number

- OE

1. Sponsor (person, company, etc. proposing this action):

Attn of: BARBARA LINKIEWICZ, ENVIRONMENTAL LICENSING MGR.NEW GENERATION PROJECTSName: FLORIDA POWER & LIGHT COMPANYAddress: 700 UNIVERSE BLVD.City: JUNO BEACH State: FL Zip: 33408-0420Telephone: (561) 691-7518 Fax: (561) 691-7049

2. Sponsor's Representative (if other than #1):

Attn. of: _____

Name: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone: _____ Fax: _____

3. Notice of: ☒ New Construction ☐ Alteration ☐ Existing4. Duration: ☐ Permanent ☒ Temporary5. Work Schedule: Beginning May 2005 End Sept. 20076. Type: ☐ Antenna Tower ☐ Crane ☐ Building ☐ Power Line☐ Landfill ☐ Water Tank ☐ Other EXHAUST STACKS

7. Marking/Painting and/or Lighting Preferred:

☐ Red Lights and Paint ☐ Dual - Red and Medium Intensity White☐ White - Medium Intensity ☐ Dual - Red and High Intensity White☐ White - High Intensity ☐ Other _____

8. FCC Antenna Structure Registration Number (if applicable):

N/A9. Latitude: Stack 1: 25° 26' 18.60" Stack 2: 25° 26' 18.59"Stack 3: 25° 26' 18.58" Stack 4: 25° 26' 18.57"10. Longitude: Stack 1: 80° 20' 01.83" Stack 2: 80° 20' 00.35"Stack 3: 80° 19' 57.27" Stack 4: 80° 19' 55.79"11. Datum: ☐ NAD 83 ☒ NAD 27 ☐ Other _____12. Nearest: City: HOMESTEAD State: FL 33035

13. Nearest Public-use (not private-use) or Military Airport or Heliport:

MIAMI INTERNATIONAL AIRPORT/HOMESTEAD AIR FORCE BASE14. Distance from #13. to Structure: 24 MILES/4.5 MILES15. Direction from #13. to Structure: SOUTH/SOUTHEAST16. Site Elevation (AMSL): 14 ft.17. Total Structure Height (AGL): 150 ft.18. Overall height (#16. + #17.) (AMSL): 164 ft.

19. Previous FAA Aeronautical Study Number (if applicable):

N/A - OE20. Description of Location: (Attach a USGS 7.5 minute
Quadrangle Map with the precise site marked and any certified survey.)The plant site lies approximately 8 miles east of Florida City, Florida. It is
approximately 9 miles east of the intersection of U.S. 1 and Palm Drive (SW
344th Street). See attached USGS map.

21. Complete Description of Proposal:

Construction of four new 150-foot (maximum potential height AGL) exhaust stacks for a combined-cycle combustion turbine power plant.

For this application, the four new 150-foot exhaust stacks are identified as Stacks 1 through 4.

Frequency/Power (kW)

Notice is required by 14 Code of Federal Regulations, part 77 pursuant to 49 U.S.C., Section 44718. Persons who knowingly and willingly violate the notice requirements of part 77 are subject to a civil penalty of \$1,000 per day until the notice is received, pursuant to 49 U.S.C., section 46301 (a).

I hereby certify that all of the above statements made by me are true, complete, and correct to the best of my knowledge. In addition, I agree to mark and light the structure in accordance with established marking and lighting standards as necessary.

Date

11/14/2003

Typed or Printed name and Title of Person Filing Notice

Barbara Linkiewicz
Environmental Licensing Manager, New Generation Projects

Signature

U.S. Department of Transportation
Federal Aviation Administration

Failure To Provide All Requested Information May Delay Processing of Your Notice

Notice of Proposed Construction or Alteration

FOR FAA USE ONLY

Aeronautical Study Number

- - - OE

1. Sponsor (person, company, etc. proposing this action):

Attn. of: BARBARA LINKIEWICZ, ENVIRONMENTAL LICENSING MGR.GENERATION PROJECTSName: FLORIDA POWER & LIGHT COMPANYAddress: 700 UNIVERSE BLVD.City: JUNO BEACH State: FL Zip: 33408-0420Telephone: (561) 691-7518 Fax: (561) 691-7049

2. Sponsor's Representative (if other than #1):

Attn. of: _____

Name: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone: _____ Fax: _____

3. Notice of: ☒ New Construction ☐ Alteration ☐ Existing4. Duration: ☐ Permanent ☒ Temporary5. Work Schedule: Beginning May 2005 End Sept. 20076. Type: ☐ Antenna Tower ☒ Crane ☐ Building ☐ Power Line☐ Landfill ☐ Water Tank ☐ Other _____

7. Marking/Painting and/or Lighting Preferred:

☐ Red Lights and Paint ☐ Dual - Red and Medium Intensity White☐ White - Medium Intensity ☐ Dual - Red and High Intensity White☐ White - High Intensity ☐ Other _____

8. FCC Antenna Structure Registration Number (if applicable):

N/A

9. Latitude: Crane (Stack 4): 25° 26' 18.57"10. Longitude: Crane (Stack 4): 80° 19' 55.79"11. Datum: ☐ NAD 83 ☒ NAD 27 ☐ Other _____12. Nearest: City: HOMESTEAD State: FL 33035

13. Nearest Public-use (not private-use) or Military Airport or Heliport:

MIAMI INTERNATIONAL AIRPORT/HOMESTEAD AIR FORCE BASE14. Distance from #13. to Structure: 24 MILES/4.5 MILES15. Direction from #13. to Structure: SOUTH/SOUTHEAST16. Site Elevation (AMSL): 14 ft.17. Total Structure Height (AGL): 240 ft.18. Overall height (#16. + #17.) (AMSL): 254 ft.

19. Previous FAA Aeronautical Study Number (if applicable):

N/A - OE20. Description of Location: (Attach a USGS 7.5 minute
Quadrangle Map with the precise site marked and any certified survey.)The plant site lies approximately 8 miles east of Florida City, Florida. It is approximately 9 miles east of the intersection of U.S. 1 and Palm Drive (SW 344th Street). See attached USGS map.

21. Complete Description of Proposal:

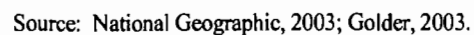
- Temporary construction cranes for use in construction of four new 150-foot (maximum potential AGL) exhaust stacks for a combined-cycle combustion turbine power plant.
- The boom height for the cranes will be under 240 feet.
- Latitude and Longitude coordinates shown for the crane are for stack #4 that is closest to the airport.

Frequency/Power (kW)

Notice is required by 14 Code of Federal Regulations, part 77 pursuant to 49 U.S.C., Section 44718. Persons who knowingly and willingly violate the notice requirements of part 77 are subject to a civil penalty of \$1,000 per day until the notice is received, pursuant to 49 U.S.C., section 46301 (a).

I hereby certify that all of the above statements made by me are true, complete, and correct to the best of my knowledge. In addition, I agree to mark or light the structure in accordance with established marking and lighting standards as necessary.

Date
11/14/2003Typed or Printed name and Title of Person Filing Notice
Barbara Linkiewicz
Environmental Licensing Manager, New Generation ProjectsSignature



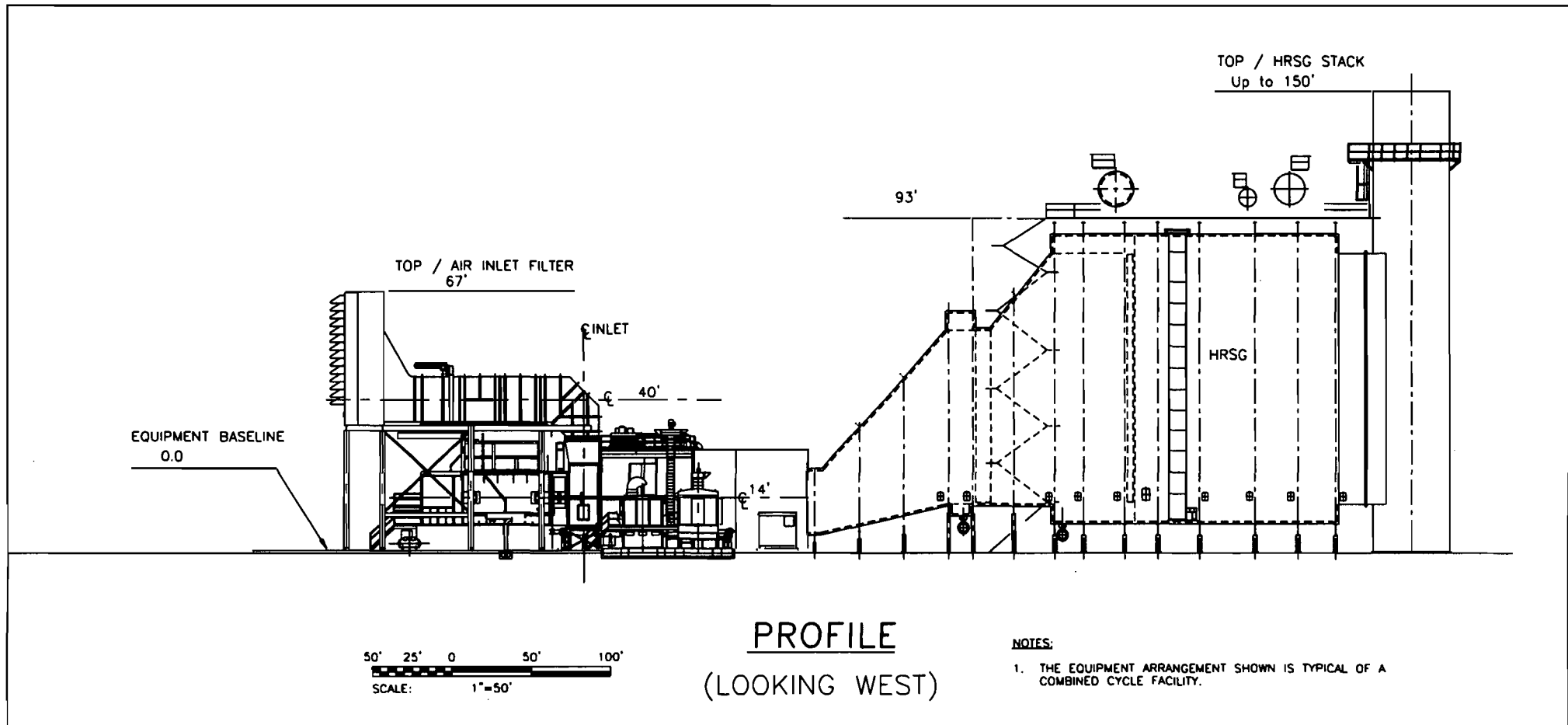


Figure 2-3. Profile of Combustion Turbine and Heat Recovery Steam Generator

Source: Black & Veatch, 2001; FPL, 2003; and Golder, 2003



APPENDIX 10.1.7

[Note: The Coastal Management Act of 1978 (Section 380.21-380.25, Florida Statutes) requires that the Coastal Zone Management Section of FDER be responsible for certification of consistency with the Florida Coastal Management Program (FCMP) for all federal licenses, permits, activities, and projects listed in Section 380.23 (3)(c), Florida Statutes, when such activities are subject to federal consistency review and affect land or water use, are seaward of the jurisdiction of the state, or there is no state agency with sole jurisdiction for such consistency review. The requirements related to Section 10 of the Rivers and Harbors Act and Section 404 of the Water Pollution Control Act are addressed in Appendix 10.1.4. Issuance of the final Site Certification will demonstrate consistency with Section 307 of the Coastal Zone Management Act. Consistency related to Part 77 of the Federal Aviation Regulations Regulators is addressed in Appendix 10.1.6.]

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an -
Application for Permit by:

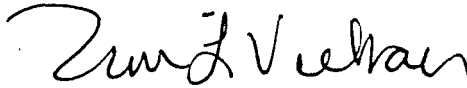
Mr. H. O. Nuñez, Plant General Manager
Florida Power and Light Company, Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

DEP File No. PSD-FL-338
FP&L Turkey Pt. Unit 5
Miami-Dade County

Enclosed is the Final Permit Number PSD-FL-338 (0250003-006-AC) to construct/install a nominal 1,150 MW combined cycle ("4 on 1") unit and auxiliary equipment at the Turkey Point Fossil Plant near Homestead, Miami-Dade County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.



Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

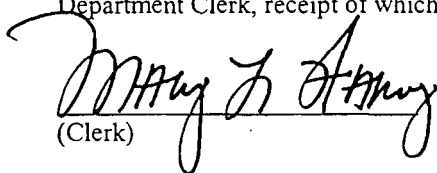
The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were sent by U.S. Mail or electronic mail before the close of business on 2/8/05 to the person(s) listed:

H. O. Nuñez, FPL*
John Gnecco, FPL
Randall LaBauve, FPL*
Barbara Linkiewicz, FPL
Mayor, Miami-Dade County
Mayor, City of Homestead
Mayor, Florida City
John Benjamin, Everglades National Park
Linda Canzanelli, Biscayne National Park

Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Steven L. Palmer, DEP Siting Office
Kevin Neal, DEP SED
Bruce Offord, DEP SED
Paul Darst, Department of Community Affairs
Chair, Miami-Dade County EQCB
H. Patrick Wong, Miami-Dade County DERM
Ken Kosky, P.E., Golder

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

 2/8/05
(Clerk) (Date)

FINAL DETERMINATION
File No. 0250003-006-AC (PSD-FL-338)
FP&L TURKEY POINT POWER PLANT
COMBINED CYCLE UNIT 5

The Department distributed a Public Notice package on May 28, 2004 for the project to construct a natural gas-fired combined cycle unit to be known as Unit 5 – FP&L Turkey Point Power Plant east of Homestead and Florida City and adjacent to Biscayne Bay, Miami-Dade County. The 1150MW project consists of four nominal 170 MW General Electric combustion turbine-electrical generators, four heat recovery steam generators, a 470 MW steam-electrical generator, and a mechanical draft cooling tower. The Public Notice of Intent to Issue was published in the June 10th edition of the Miami Herald.

No requests for public meetings or administrative hearings were received on the Notice of Intent to Issue. An evidentiary hearing was held on September 20-21, 2004 and a Recommended Order was entered on November 18, 2004 to:

“Grant full and final certification to Florida Power & Light Company, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Turkey Point Unit 5, representing a 1150 MW combined cycle unit, as described in the Site Certification Application and the evidence presented at the certification hearing, and subject to the Conditions of Certification.” Final Certification was approved on February 1, 2005.

The Department is required to take final action on the PSD Permit Application and the draft permit within 30 days following Final Certification by the Siting Board. This Final Determination recapitulates all comments and changes since the distribution of the Notice of Intent to Issue PSD Permit on May 28, 2004.

No comments suggesting adverse impacts were received. The comments of the EPA, NPS and FP&L recited or described below (*italics*) followed by the Department’s responses.

1. *EPA’s letter dated July 8, 2004 states, “Condition 9 of the draft PSD permit contains a table of CO emissions limits that are applicable to various operating modes of the four new CTs. The table contains two columns of emission limits. Compliance with the first column of emission limits shall be demonstrated by 3-run stack testing, while compliance with the second column of emission limits shall be demonstrated using a continuous emissions monitoring system (CEMS) with a 24-hour averaging time”.*

The Department agrees with the given description of the table, the limits and how compliance will be demonstrated. But as noted in item 5 below, we reserve use of CEMS for short-term.

2. *EPA’s letter further states, “It is our understanding from conversations with the Florida Department of Environmental Protection (FDEP) that the first column of CO emission limits represents the BACT emission limits (i.e., 4.1 ppm in normal mode, 7.6 ppm with duct burning, etc.) and the second column of CO emission limits contains higher limits that have been proposed to simplify the recordkeeping process (i.e., 8.0 ppm for all modes except power augmentation, etc.). First, we would like to point out that the distinction between the two sets of emission limits described above is not clear in the current draft PSD permit”.*

The 5 ppm value (~4 when corrected to 15% O₂) is the lowest CO limit guaranteed to-date by any combustion turbine manufacturer without requiring installation of additional control equipment such as oxidation catalyst. The 7.6 ppm limit with duct burning and 8 ppm limit for fuel oil use are also the lowest values in permits without oxidation catalyst and represent values roughly equivalent to ambient air quality standards even though measured at the stack.

To simplify recordkeeping, a 24-hour limit of 8 ppm was proposed because it is possible that on a given day, a combined cycle unit will actually operate with the duct burner on at all times. The distinction between the limits is maintained because initial and annual stack tests are required for the three key modes in conjunction with the annual RATA tests for the CEMS.

The remaining concern is that the low guaranteed values for the normal gas-firing case (without high power modes) is not accounted for in the CEMS based limit. To insure that the units cannot possibly be operated at 8 ppm at all times regardless of mode, the Department will set a limit of 6 ppmvd @15% O₂ on a 12 month basis, rolled monthly. This represents an approximate weighted average of emissions based on permitted firing modes. It assumes that the individual units will operate all of the allowable hours in the high power or oil-firing modes and the difference on the normal gas only mode.

The additional requirement will not cause increases or reductions in emissions or cause undue recordkeeping burdens. However the new requirement better represents the long-term, time averaged, emission estimates over all modes of operation consistent with the application.

Based on review of CO data after startup, the Department expects actual average emissions for all modes between 1 to 2 ppm except for the limited power augmentation mode. It is not yet possible to obtain the very low guarantees without installing oxidation catalyst. For reference, emissions during the limited power augmentation mode will likely be between 5 and 9 ppm.

3. *EPA's letter states, "If the emission limits are left as they are, this relationship should be better described in the table itself or in a permitting note immediately preceding the table".*

The table has been updated to clarify CO emission limits:

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ²	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.0, 24-hr
	<u>Oil/Gas</u>	<u>All Modes</u>	<u>NA</u>	<u>NA</u>	<u>6, 12 months</u>

- a. Continuous compliance with the 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
4. *EPA's letter states, "We agree with FDEP that initial compliance with the BACT limits can be determined using a stack test; however, continuous compliance with the BACT emission limits should be demonstrated by use of the CEMS".*

The issue relates to CO. The table now represents a reasonable compromise that provides an additional incentive to the applicant to operate based on initial and annual stack tests. The alternative of separate continuous compliance for each and every mode is feasible but cumbersome. Continuous compliance is demonstrated by the use of CEMS for the 24-hour and 12 month standards.

5. *EPA's letter states, "Condition 19 of the draft PSD permit declares that FDEP "reserves the right" to use data from the CEMS to determine compliance with the short-term CO emission limits. We believe that this condition is not definite enough to enforce the BACT emission limits using CEMS".*

This "right" that was placed in the draft permit provides a powerful incentive to maintain the equipment such that the lowest emissions are achieved. It is not much different than the use of "any credible evidence" in addition to the already stringent stack test and CEM-based BACT emission limits. With the new weighted annual limit for CO, there is an even bigger incentive to comply with the short-term values.

6. *EPA's letter states, "If it is decided that the CEMS will be used to determine compliance with the BACT emission limits, we recommend that the final PSD permit require use of an averaging time shorter than 24 hours. Since there exist short-term CO national ambient air quality standards (NAAQS) with averaging times below 24 hours (i.e., 1-hour and 8-hour standards), we believe that the averaging times should be more consistent with the applicable NAAQS averaging times".*

The range of emission limits for the various modes is 4 to 14 ppm, while expected emissions are 1 to 2 ppm at the stack exit and prior to dilution and dispersion for all but one case. We actually expect emissions of 5 to 9 ppm for the limited power augmentation case. The 1-hour and 8-hour ground level National Ambient Air Quality Standards for CO are 35 and 9 ppm respectively. Even if all of the allowable emissions in a 24-hour period were compressed into a single hour, the ground level concentration would still not exceed 9 ppm. Thus the 24-hour limit is protective of the 1 and 8-hour CO standards. There are no increments for CO that might otherwise reinforce the need for the shorter averaging periods.

7. *EPA states, "any operating limits which were used in the analyses on a per turbine basis should be included in the draft PSD permit on a per turbine basis. The draft PSD permit does contain per turbine limits on the amount of time the CTs can operate in power augmentation mode and while firing fuel oil. However, condition 8(e) of the draft PSD permit contains one aggregate limit (5,702,400 MMBtu) for all four CTs restricting the*

amount of duct firing that is allowed in a year. In order for the BACT analysis to remain valid, the final PSD permit should contain the appropriate duct firing limit on a per turbine basis (i.e., 1,425,600 MMBtu/year). Alternatively, if the applicant wishes to retain the aggregate limit, a revised BACT analysis should be performed (based on the worst case scenario of one CT operating the duct burners all year long) which demonstrates that the outcome of the BACT analysis would remain unchanged”.

The point is well taken and the following review was conducted to determine if a further BACT review is needed. Referring to 4 above, the Department has added a long-term limit of 6 ppm CO.

The scenario of firing a single duct burner continuously for the year while hardly firing the others is unrealistic but theoretically possible and needs to be explored. The practical consequence of continuous duct firing is that the given unit must still comply with the BACT NO_x limit of 2 ppm. NO_x emissions will actually be controlled to that level or slightly less by the SCR system.

The CO could theoretically be 7.6 ppm of CO. However if they use the duct burners continuously, they are limited by the new 12 month of 6 ppm (corrected to 15% O₂). GE will guarantee CO emissions from its combustion turbines to 5 ppm uncorrected (~ 4.1 ppm corrected). The duct burner manufacturer has its own guarantee regarding what a duct burner *theoretically adds* to the CO from the combustion turbine.

The Department's analysis of *actual* operating data shows that duct burners do not affect CO emissions in a meaningful manner for F-Class installations. Exhaust gas from the combustion turbine is already at a high temperature, turbulent, and contains a lot of oxygen promoting good CO burnout. The guarantees for the different components have not yet been reconciled into a single low CO guarantee without requiring oxidation catalyst.

Based on the Department's analysis of data from installations with GE F-Class combustion turbines operating in conjunction with duct burners, actual emissions will be in the range of 1 to 2 ppm @15% O₂. The data on the duct burners operating in conjunction with the combustion turbines was included in the Technical Evaluation.

The Department believes that it is not cost-effective to install oxidation catalyst to reduce CO emissions for this part-time mode from 6 to say 1 ppm @15% O₂ when the practical reduction will actually be from the 1 – 2 ppm range to 0.2– 0.4 ppm (assuming roughly 80 percent efficiency). The equipment providers have given their best guarantees short of installing unnecessary oxidation catalyst. This FP&L project was the first to obtain such low guarantees.

Basically, the Department has required FP&L to meet a value lower than the combined guarantees of the combustion turbine provider and the duct burner provider. The data from installations in Florida and the underpinning provided in the Technical Evaluation provide further reasonable assurance that the new long term limit can be achieved and that emissions will in fact be substantially less than permitted.

The Department agrees that FP&L will be able to theoretically fire the duct burner all of the time on one unit and none of the time on others. Although this is a very unlikely situation for economic reasons, the Department believes that the outcome of the BACT analysis would remain unchanged based on the information above.

8. *In the NPS letter dated July 2, 2004, NPS states, "Although FDEP acknowledges that the high power operating modes 'can cause greater uncontrolled NO_x emissions' the proposed permit explicitly exempts FP&L from any emission limits while operating in this mode".*

The Department's BACT determination of 2.0 ppm NO_x limit does apply to all modes except for use of back up ultralow sulfur fuel oil. The Department clarified this issue during discussions with NPS experts on November 24, 2004. After jointly studying the table containing the emissions limits for each power mode, we agreed that the proposed permit does not exempt high power modes from the BACT determination.

9. *In the same letter, the NPS states, "FP&L will reduce their NO_x limit from 2.5 ppm to 2.0 ppm when burning natural gas and from 10.0 ppm to 8.0 ppm when burning oil At the lower NO_x emission rates; we anticipate that visibility impacts at Biscayne NP will also be reduced. Therefore, we do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP".*

The Department agrees with this assessment.

10. *The NPS letter included comments related to the averaging time of the 24-hr NO_x emission limit of 2.0 ppmvd @15% O₂ when burning natural gas. It states, "BACT is an emission limit, and emission limits typically consist of a numerical limit in terms of mass of pollutant per unit time, unit volume and/or per unit of heat input. These emission limits are also typically specified over a prescribed averaging period; due to the inherent variability in emissions and the performance of the control technology, the longer the averaging period, the easier it is to meet a given limit.*

"Although it states in the TEPD top-down analysis that 'The Top emission limit is considered by the Department to be 2.0 ppmvd @ 15% O₂ on a 1-hour average,' FDEP goes on to set FP&L's proposed permit limit for natural gas combustion based upon a 24-hour average, with no explanation provided for the longer averaging period. Therefore, FDEP did not choose the 'top' control technology, nor did it justify proposing a less stringent limit.

"We believe that the 24-hour block averaging periods are much too long when compared to similar combustion turbines meeting the same outlet concentration limits for the one-hour or three-hour averages. The effect of the much longer averaging periods is to reduce the stringency of the limits relative to other permits. For example, Clark County, Nevada, has determined that a 2.0 ppm limit (1-hr average) represents BACT for the Diamond Generating, Ivanpah Energy combustion turbine project. The Virginia Department of Environmental Protection has permitted an identical limit for the CPV Warren County combustion turbine project. Turkey Point should show why it cannot meet a 2.0 ppm limit on a one-hour basis, as it is required of other similar projects".

It is important to note that the NSPS standard for combustion turbines is approximately 108 ppm for F-Class units on a 4 hour basis. The proposed BACT is 2 ppm on a 24-hr basis or only 2 percent of the standard. This is virtually zero for this pollutant in terms of emissions and it is very difficult to achieve lower emissions.

In addition, the NO_x ambient standard is on an annual basis. The 24-hour standard for this source is suitable to limit effects on visibility and ozone formation potential. A one-hour value is achievable but runs the risk that small exceedances that do not have any impacts will be categorized as violations. In any case, the facility would have to compensate quickly when the value exceeds 2 ppm even on a 24-hour average. For example, if a unit were to emit even 10 ppm for four hours, it would have to achieve 0.4 ppm during the preceding and subsequent 20 hours to avoid exceeding the 24-hr limit.

While it is difficult to prove that it is not cost-effective to reduce the averaging time to 1 hour, the Department has a great deal of experience balancing emission limits and averaging times with environmental protection and sensible business operation. This case-by-case BACT determination and combination of limit and averaging time will allow this facility to conduct its business, protect the environment, respond smoothly to operational variations, and dispatch power from other system facilities in an orderly fashion.

The considerations in out-of-state non-attainment areas or sources that influence such non-attainment areas may be somewhat different. The Department does not assert that any of the determinations made in the areas described by NPS are erroneous with respect to limits or averaging time.

In the conversations of November 24, the NPS personnel acknowledged that the Department would make the final BACT determination.

11. *NPS states in its letter dated July 2, 2004, "As referenced in our February 24, 2004 letter to FDEP regarding the emission inventories presented in the FP&L permit application, we reiterate that we would like to know how sources were selected for the inventory, and how emissions from those sources were determined."*

FP&L and Golder referred to their letter dated April 19, 2004 that was in response to the NPS letter dated February 24. The relevant parts follow.

"Cumulative Source Modeling- The detailed stack, operating, and emission data for the facilities with SO₂ and PM₁₀ sources presented in Tables 6-3 and 6-4 are provided in Tables D-1 and D-2 of Appendix D to the Air Construction Permit/PSD Application, Appendix 10.1.5.

"These data were based on information provided from FDEP, available from recent PSD permit applications, Title V permits, and supplemented with current and historical information available within Golder. The air modeling data were obtained from several recently submitted and reviewed air permit applications in which PSD Class I increment or significant impact analyses were performed at the Everglades National Park. These applications include the modifications to U.S. Sugar Corporation's Clewiston Mill (proposed Boiler No. 8, March 2003; Boiler No. 4 and Sugar Refinery, October 2000); Palm Beach

Power Corporation's Cogeneration Facility (April 2002); and FPL's Martin Power Plant Expansion Project, Unit No. 8 (February 2002).

"The major source baseline date for Florida is January 6, 1975 for both SO₂ and PM₁₀ (adopted and incorporated by reference in Rule 62-204.800, F.A.C.). The minor source baseline date for SO₂ and PM₁₀ has been set as December 27, 1977 for the entire State of Florida (Rule 62-204.360(1) and (2), F.A.C.).

"Based on these baseline dates, the baseline and PSD-increment consuming sources of SO₂ and PM₁₀ emissions for the sources in the inventory were developed from the available information discussed previously. The baseline and PSD increment consuming sources are identified in Tables D-1 and D-2 of Appendix A to the Air Construction/PSD Application.

"It should be noted that, although the highest 24-hour average SO₂ concentrations were predicted to exceed 24-hour SO₂ PSD Class I increment for 1990 and 1992, there were no predicted violations of the increment based on the highest, second highest values. Rule 62-272.500 F.A.C. and 40 CFR 52.21(c) support the use of the highest, second highest values when determining compliance with the 24-hour SO₂ PSD Class I increment".

12. *During the telephone discussion of November 24, 2004 NPS advised that the inventory and the modeling for SO₂ Class I Increment Consumption described in the Golder/FP&L response did not, but should have, included minor sources, transportation, and changes in major sources on an actual to actual basis since 1977.*

Turkey Pt. Unit 5 will fire the lowest sulfur fuels available. The project will be the first in Florida to commit to ultralow sulfur fuel oil used as backup fuel to natural gas. The backup fuel actually has a lower sulfur specification than natural gas. NPS advised (see 9 above) they do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP. The Department agrees with NPS.

After receiving clarification from NPS on November 24, 2004 the Department reviewed the issues raised by the NPS. The Department agrees that the analysis for Class I SO₂ Increment Consumption does not comport with the method most recently described by the NPS.

The Department conducted a qualitative and semi-quantitative evaluation and determined that additional modeling, if conducted in the manner described by NPS, will most likely show expansion rather than consumption of SO₂ increment by development since the late 1970's and that the proposed project will not appreciably change that trend. The Department responded to the NPS comments by electronic mail on December 8, 2004. The communication contained most of the following analysis:

The Department obtained information from FP&L regarding actual emissions from the existing Turkey Point units circa 1977. In 2002, emissions were 9,135 tons from Turkey Point Units 1 and 2. During the 1974-1978 timeframe, emissions from Turkey Points Units 1 and 2 were always much higher and averaged 16,558 tons per year. Therefore, the biggest sources (Units 1 and 2) likely to interact with the new project (that will emit 193 tons per year) have expanded increment rather than consumed increment. The summary table of emissions from Turkey Point is shown below.

Emissions of SO₂ from Turkey Point Fossil Plant (1974-78, and 2002)

<u>Year</u>	<u>Tons per year</u>
1974	18,043
1975	18,058
1976	18,028
1977	13,519
1978	15,140
1974-1978	16,558 (average)
2002	9,135
Reduction	~ 7,000

Table 16 from the Technical Evaluation distributed with the Department's Draft PSD Permit lists the largest stationary SO₂ sources in Miami-Dade County and their *actual* emissions.

Table 16. Major Sources of SO₂ in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Florida Power & Light	Turkey Pt. Plant (existing boilers)	9,135 (EPA)
Titan Industries	Tarmac Pennsucco Cement	~ 1,000 (est.)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	231
<i>Florida Power & Light</i>	<i>Turkey Pt. Plant (proposed project)</i>	<i>193</i>
Waste Management	Medley Landfill and Recycling	129
Miami-Dade County WASD	MDWASD/Central District WWTP	88

The magnitude of actual large SO₂ emission sources drops off very rapidly after the existing Turkey Point Fossil Plant. Titan/Tarmac Pennsucco Cement will emit closer to 50 TPY (rather than ~1000 TPY) in future years, having modernized their process in 2004. Rinker Cement previously emitted over 1000 TPY of SO₂ and now emits approximately 50 TPY since a modernization project in 2000. General Portland Cement was another significant emitter of SO₂ that closed around 1985.

The 7,000 TPY actual reduction from the collocated Turkey Point Units 1 and 2 and the reductions from reductions in regional cement manufacturing SO₂ emissions would overwhelm any possible effects from the 193 TPY Turkey Point Unit 5.

During the application review phase, FP&L submitted estimates that 2008-2012 SO₂ emissions from Turkey Point Units 1 and 2 will be approximately 5,733 tons per year. The Department does not necessarily agree with or reject these estimates given uncertain fuel prices.

The Department also included in the Technical Evaluation an inventory of the different categories of emissions in Miami-Dade County. The small magnitude of the proposed Turkey Pt. Unit 5 project is obvious.

Table 21. Pollutant Emissions in Miami-Dade County by Source Category (2002)

Source Category	SO ₂	NO _x	CO	PM ₁₀	VOC	NH ₃
Stationary Sources	10,262	12,929	3,891	2,516	1,757	0 (?)
Area Sources	13,266	4,580	78,670	35,438	53,167	2,925
On-Road Mobile	1,989	46,158	492,121	1,230	49,007	1,940
Non-Road Mobile	1,976	19,062	197,091	24,946	15,646	11
Total	27,492	82,729	771,773	64,131	119,578	4,876
<i>Turkey Pt. Unit 5</i>	193	320	450	229	68	~200

Transportation SO₂ emissions are likely lower in recent years than in the baseline years of the late 1970's. Most of the decline is due to the use of 0.05% sulfur fuel oil for transportation versus the previous higher sulfur specifications in gasoline and diesel (e.g. 0.5% sulfur for diesel). Ultralow sulfur fuel oil (0.0015% sulfur) for transportation sources has been mandated so the trend will continue. Any area source/minor source increases would have been very small compared with the reductions at Turkey Point.

The Department issued a permit in 1998 that lead to the actual SO₂ emissions reductions greater than 20,000 TPY from the FP&L Fort Myers Power Plant located 97 km north of the westernmost part of ENP. This expanded increment over the ENP from a generally northwesterly direction. The 1992 natural gas repowering of the FP&L Lauderdale Plant in Dania expanded increment at ENP from a generally northeasterly direction.

Similarly, the FP&L Port Everglades Plant in Broward County and the FP&L Rivera Plant in Palm Beach County use cleaner fuel oil than required and use substantial amounts of natural gas. This probably adds further to any actual to actual analysis of increment expansion.

In conclusion all indications are that SO₂ emissions have been reduced locally and regionally. A modeling effort would likely show improvements rather than degradation related to SO₂ at the ENP since the late 1970's. The Department believes this analysis is sufficient to support issuance of this permit without further detailed analysis.

13. In a letter received July 2, 2004 from FP&L (Barbara Linkiewicz), FPL requested revision of Section III, specific condition 8, b. as follows:

Authorized fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. ~~Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months.~~ The four gas turbines shall fire no more than a cumulative total of 28,028,168 gallons of fuel oil during any calendar year."

Following discussions with the Department and considering EPA's concern regarding the fuel versus hourly limitation for duct burning, FP&L withdrew the request. In this case, the theoretical, but unlikely use of fuel oil for 2000 hours in a single unit and 0 hours in the others might have changed the final BACT.

By electronic communication dated August 15, 2004, FP&L replaced their request in Item 13 with the following:

Authorized Fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months calendar year.

The revised request has no practical effect on emissions or the BACT basis for SO₂. The Department will revise the Authorized Fuels condition per the revised request.

14. In the July 2, 2004 letter, FP&L requests the following change to Section III, Specific Condition 9f.:

Each SCR system shall be designed and operated for ammonia slip limit of less no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs.

The Department will revise this emission standard adding the proposed language.

15. In the July 2, 2004 letter, FPL states:

"In Section III, pages 14-15, we request the clarifications below. Recognizing that quarterly reports contain all NSPS and State requirements, this clarification combines the quarterly and semi annual reports. The proposed language below also makes Condition 27 consistent with Condition 25a regarding the monitoring period".

Condition 27. ~~Semiannual NSPS Excess Emissions Report. Quarterly Excess Emission Report:~~ In accordance with 40 CFR 60.7 (d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards ~~w~~ Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards following the NSPS format provided in Appendix XS of this permit. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_x emission standard identified in Appendix GG; and any ~~daily~~ monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown. ~~An example of the report is provided on Appendix XS. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]~~

Condition 28. ~~Quarterly Permit Excess Emissions Report~~ Semiannual NSPS Excess Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the permit standards. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]. The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.

The Department will adopt these changes with some additional clarification. The reports will include excess emissions related to the BACT determination and any other SIP-based emission limits in addition to the NSPS excess emission reporting requirements.

The other change reflects the recent revision of 40 CFR 60 Subpart GG that defines excess emissions based on CEMS in lieu of water-to-fuel ratio.

16. On August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. The relevant provision of the rule that stays the effectiveness for units such as proposed at Turkey Point follows:

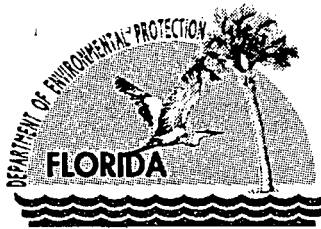
40 CFR 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

The Department has updated relevant parts of the permit and summarized in Appendix YYYYY of the permit, the applicable requirements of Subparts A and YYYYY in 40 CFR 63.

CONCLUSION

The final action of the Department is to issue the permit with the changes noted above.



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

PERMITTEE:

Florida Power & Light
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:

Scott Stone, Plant General Manager

FP&L Turkey Point Fossil Plant
DEP File No. 0250003-006-AC
Permit No. PSD-FL-338
SIC No. 4911
Expires: December 31, 2008

PROJECT AND LOCATION

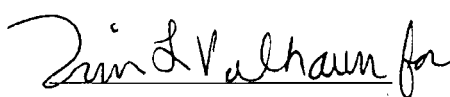
This permit authorizes the construction of Unit 5 at the existing FP&L Turkey Point Fossil Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will include four 170 MW gas turbine-electrical generator sets, four heat recovery steam generators, a single 470 MW steam turbine-electrical generator, and a mechanical draft cooling tower. The existing FP&L Turkey Point Fossil Plant is located east of Homestead and Florida City and next to Biscayne Bay in Miami-Dade County, Florida. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

- Section I. General Information
- Section II. Administrative Requirements
- Section III. Emissions Units Specific Conditions
- Section IV. Appendices

 2/8/05

Michael G. Cooke, Director (Date)
Division of Air Resources Management

SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The existing Turkey Point Fossil Plant currently consists of two fossil fuel-fired steam electrical generating units and five “Black Start” diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The proposed “4 on 1” combined cycle Unit 5, which will consist of four gas turbines (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. New combined cycle Unit 5 will have a total generating capacity of approximately 1150 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
005	Unit 5A gas turbine (170 MW) with supplementary-fired heat recovery steam generator
006	Unit 5B gas turbine (170 MW) with supplementary-fired heat recovery steam generator
007	Unit 5C gas turbine (170 MW) with supplementary-fired heat recovery steam generator
008	Unit 5D gas turbine (170 MW) with supplementary-fired heat recovery steam generator
009	One distillate fuel oil storage tank for Unit 5 gas turbines
010	Mechanical draft cooling tower for Unit 5

Note: FPL Turkey Point Fossil Plant Unit 5 consists of four gas combustion turbine-electrical generator sets (Units 5A-5D), four supplementary gas-fired heat recovery steam generators (HRSGs), and a single steam turbine-electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is subject to 40 CFR 63, Subpart YYYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYYY of this permit).

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as “attainment,” “maintenance,” or “unclassifiable” for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a “fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input”, which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

SECTION I. GENERAL INFORMATION

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Miami-Dade County Department of Environmental Resources Management (DERM), Air Quality Management, 33 Southwest 2nd Avenue, Suite 900, Miami, Florida 33130-1540.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix CF. Citation Format and Definitions

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

Appendix YYYY. NESHAP Requirements for Gas Turbines from 40 CFR 63, Subpart YYYY

Appendix XS. Semiannual NSPS Excess Emissions Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on November 14, 2003;
- Department PSD Application Sufficiency comments dated January 2, 2004;
- Environmental Protection Agency Region 4 letter dated January 15, 2004;
- Department of Interior/NPS letter dated February 27, 2004;
- Sufficiency Responses received March 1, 2004;
- Letter dated April 19, 2004 from Golder in response to NPS letter dated February 27, 2004;
- Draft permit package issued on May 28, 2004;
- Letter dated July 1, 2004 from FP&L regarding draft permit;
- Letter dated July 2, 2004 from National Park Service regarding draft permit;
- Letter dated July 8, 2004 from EPA regarding draft permit;
- Final Certification by the Power Plant Siting Board on February 1, 2005; and
- Final Determination on PSD Permit distributed concurrently with Final PSD Permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]
4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]
6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]
7. Title V Permit Revision: The permittee shall submit an application for a revised Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

This section of the permit addresses the following emissions units.

Emissions Units 005, 006, 007, 008

Description: Emissions units 005, 006, 007, and 008 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate supplementary-fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a generating capacity of 470 MW. The total generating capacity of the "4 on 1" combined cycle unit is approximately 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, PM/PM₁₀, SAM, SO₂ and VOC. Dry Low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system further reduces NO_x emissions.

Stack Parameters: Each HRSG has a stack at least 130 feet tall with a nominal diameter of 19 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics:

<u>Fuel</u>	<u>Heat Input Rate (LHV)</u>	<u>Compressor Inlet Temp.</u>	<u>Exhaust Temp., °F</u>	<u>Flow Rate ACFM</u>
Gas	1,608 MMBtu/hour	59° F	202° F	1,023,872
Oil	1,830 MMBtu/hour	59° F	295° F	1,224,407

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. **BACT Determinations:** Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfuric acid mist (SAM), sulfur dioxide (SO₂) and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
2. **NSPS Requirements:** The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]
- 2.a. **NESHAP Requirements:** The combustion turbines are subject to 40 CFR 63, Subpart YYYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYYY until EPA takes final action to require compliance and publishes a document in the Federal Register.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the SpeedtronicTM automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to 290 °F before combustion to increase overall unit efficiency. This will be accomplished by feedwater heat exchangers. [Application; Design]
4. Gas Turbine NO_x Controls
 - a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_x emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH₃) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_x and NH₃ emissions.
 - d. *Ammonia Storage*: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Design; Rule 62-212.400(BACT), F.A.C.]
5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (5A-5D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_x/MMBtu. {*Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.*} [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,608 MMBtu per hour when firing natural gas and 1,830 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]
8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
 - a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
 - b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any calendar year.
 - c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
 - d. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."
 - e. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.
 - f. *High Power Modes (Peaking and Power Augmentation)*: When firing natural gas and only while practicing duct firing, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. When firing natural gas and only while practicing duct firing, steam may be injected into each gas turbine expansion section to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation," the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total hours of power augmentation plus the total hours of peaking shall not exceed 400 hours per gas turbine during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.0, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12-month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- a. Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
- b. Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

- c. The sulfur fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard and Section 24.41.1 of the Miami-Dade County Code shall be demonstrated by conducting tests in accordance with EPA Method 9.
- d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section. Compliance with the SO₂ BACT also insures compliance with Section 24.41.3 of the Miami-Dade County Code.
- e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- f. Each SCR system shall be designed and operated for ammonia slip limit of no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "PK" means peaking, "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

[Rule 62-212.400(BACT), F.A.C.]

- 10. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. This is not considered a separate mode of operation with respect to emission limits. When operating in this manner, each unit shall comply with the respective standards given in Condition 9 for each mode of operation indicated therein. [Application]
- 11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. *{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da}* [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

- 12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]
14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]
15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A “documented malfunction” means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.
 - a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold “startup of the steam turbine system” is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours:
{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}
 - b. For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.
 - c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. “Cold startup of a gas turbine/HRSG system” is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.
 - d. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

16. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer’s specifications. A “major tuning session” would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS PERFORMANCE TESTING

17. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "<http://www.epa.gov/ttn/emc/ctm.html>". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

18. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_x, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Stack test data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_x mass rate emissions standards. CO and NO_x emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]
19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_x limits for each method of operation given in Condition 9 above. [Rule 62-212.400 (BACT), F.A.C.]
20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

21. **CEM Systems:** The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_x from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_x standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
- CO Monitors.** The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - NO_x Monitors.** Each NO_x monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NO_x monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - Diluent Monitors.** The oxygen (O₂) or carbon dioxide (CO₂) content of the flue gas shall be monitored at the location where CO and NO_x are monitored to correct the measured emissions rates to 15% oxygen. If a CO₂ monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
 - 1-Hour Block Averages.** Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture).

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_x as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

- e. *24-hour Block Averages:* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_x emissions depending on the use of alternate methods of operation}.* [Rule 62-212.400(BACT), F.A.C.]
- f. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- g. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

- 22. **Ammonia Monitoring Requirements:** In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_x emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_x monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

RECORDS AND REPORTS

23. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
24. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
25. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.
- a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.
 - b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.
- The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]
26. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

27. Quarterly Excess Emission Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards (BACT, SIP, NSPS) following the NSPS format provided in Appendix XS of this permit.

For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NO_x concentration exceeds the NSPS NO_x emission standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown.

Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7, and 60.334(j)(1)]

28. Semiannual NSPS Excess Emissions Report: The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
009	One distillate fuel oil storage tank for Unit 5 gas turbines (approximately 4.2 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.; and Section 24.41.6, Miami-Dade County Code.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 4.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 5 gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. COOLING TOWER (EU 010)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
010	22-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 22-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM₁₀ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM₁₀ per year. Actual emissions are expected be lower than these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

SECTION IV. APPENDICES

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SECTION IV. APPENDIX A
NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

- § 60.1 Applicability.
- § 60.2 Definitions.
- § 60.3 Units and abbreviations.
- § 60.4 Address.
- § 60.5 Determination of construction or modification.
- § 60.6 Review of plans.
- § 60.7 Notification and Record Keeping.
- § 60.8 Performance Tests.
- § 60.9 Availability of information.
- § 60.10 State Authority.
- § 60.11 Compliance with Standards and Maintenance Requirements.
- § 60.12 Circumvention.
- § 60.13 Monitoring Requirements.
- § 60.14 Modification.
- § 60.15 Reconstruction.
- § 60.16 Priority List.
- § 60.17 Incorporations by Reference.
- § 60.18 General Control Device Requirements.
- § 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

SECTION IV. APPENDIX BD

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12 month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.
- Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂.
- The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
- The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
- Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

SECTION IV. APPENDIX BD
FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

A A Linero 2/1/05

Recommended By:

Approved By:

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

2/8/05
Date

Michael G. Cooke

Michael G. Cooke, Director
Division of Air Resources Management

2/8/05
Date

SECTION IV. APPENDIX CF
CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001" identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

- (119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.
- (179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
- (258) Shutdown - The cessation of the operation of an emissions unit for any purpose.
- (275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 5 gas turbine/HRSG systems, which are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

“Duct burner” means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

“Electric utility combined cycle gas turbine” means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Electric utility steam generating unit” means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Fossil fuel” means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

“Gross output” means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

“Potential electrical output capacity” is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

“Steam generating unit” means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM₁₀ emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil ($\leq 0.05\%$ sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO₂ emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO₂) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NO_x) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})] / (O_{sg} \times h) \quad (\text{Equation 1})$$

Where:

- E = Emission rate of NO_x from the duct burner, ng/J (lb/Mwh) gross output
- C_{sg} = Average hourly concentration of NO_x exiting the steam generating unit, ng/dscm (lb/dscf)
- C_{te} = Average hourly concentration of NO_x in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
- Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
- Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
- O_{sg} = Average hourly gross energy output from steam generating unit, J (Mwh)
- h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_x concentrations (C_{sg} and C_{te}). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Q_{sg} and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1- hour runs) for the initial performance tests. Thereafter, compliance with the NO_x limits established in the PSD permit shall demonstrate compliance with NO_x limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

SECTION IV. APPENDIX Da

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_x standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_x emission rate when demonstrating compliance with the NO_x standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
 - a. Have access to and copy and records that must be kept under the conditions of the permit;
 - b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
 - c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
 - a. A description of and cause of non-compliance; and
 - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
 - a. Determination of Best Available Control Technology (X);
 - b. Determination of Prevention of Significant Deterioration (X);
 - c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
 - d. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
 - a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - c. Records of monitoring information shall include:
 - 1) The date, exact place, and time of sampling or measurements;
 - 2) The person responsible for performing the sampling or measurements;
 - 3) The dates analyses were performed;
 - 4) The person responsible for performing the analyses;
 - 5) The analytical techniques or methods used; and
 - 6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SECTION IV. APPENDIX GG
NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The Unit 5 gas turbines are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.330 Applicability and Designation of Affected Facility.

Each Unit 5 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

- (a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.
- (b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.
- (c) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.
- (g) ISO standard day conditions mean 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.
- (h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.
- (i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.
- (j) Base load means the load level at which a gas turbine is normally operated.
- (q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_x) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

$$\text{STD} = 0.0075 \frac{(14.4)}{Y} + F$$

Where:

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NO_x contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NO_x emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NO_x standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

SECTION IV. APPENDIX GG
NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil ($\leq 0.05\%$ sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_x standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NO_x emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_x) for each run using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) (\text{Pr}/\text{Po})^{0.5} e^{19(\text{Ho}-0.00633)} (288^\circ\text{K}/\text{Ta})^{1.53}$$

Where:

- NO_x = Emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, volume percent
- NO_{x0} = Observed NO_x concentration, ppm by volume
- Pr = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
- Po = Observed combustor inlet absolute pressure at test, mm Hg
- Ho = Observed humidity of ambient air, g H_2O /g air
- e = Transcendental constant, 2.718
- Ta = Ambient temperature, $^\circ\text{K}$

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_x monitor shall be used to demonstrate compliance with the specified NO_x limits. The permittee is allowed to make the initial compliance demonstration for NO_x emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_x monitor. The permittee is not required to have the NO_x monitor continuously correct NO_x emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]
12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
 - a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
 - b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
 - c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.[Rule 62-297.310(4), F.A.C.]
14. Determination of Process Variables
 - a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
 - b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.[Rule 62-297.310(5), F.A.C.]
15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.
16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]
17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]
18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

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STANDARD CONDITIONS

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

- 1) The type, location, and designation of the emissions unit tested.
- 2) The facility at which the emissions unit is located.
- 3) The owner or operator of the emissions unit.
- 4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
- 5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
- 6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
- 7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
- 8) The date, starting time and duration of each sampling run.
- 9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
- 10) The number of points sampled and configuration and location of the sampling plane.
- 11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
- 12) The type, manufacturer and configuration of the sampling equipment used.
- 13) Data related to the required calibration of the test equipment.
- 14) Data on the identification, processing and weights of all filters used.
- 15) Data on the types and amounts of any chemical solutions used.
- 16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
- 17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
- 18) All measured and calculated data required to be determined by each applicable test procedure for each run.
- 19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
- 20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
- 21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION IV. APPENDIX XS
SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant (*Circle One*): SO₂ NO_x TRS H₂S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ¹: _____

Emission data summary ¹	CMS performance summary ¹
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. Total duration of excess emissions x (100) / [Total source operating time] % ²	1. CMS downtime in reporting period due to: a. Monitor equipment malfunctions b. Non-Monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CMS Downtime 3. [Total CMS Downtime] x (100) / [Total source operating time] % ²

¹ For opacity, record all times in minutes. For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ Date: _____

Title: _____

SECTION IV. APPENDIX YYYY
NESHAP REQUIREMENTS FOR GAS TURBINES

Applicability of NESHAP Subpart YYYY

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O₂). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

According to General Electric, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposed to meet the limit proposed in YYYY of 91 ppbvd based on the performance of the GE 7FA unit. The very low CO and VOC emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_x combustion technology employed by these units ensure that formaldehyde emissions will be at the lowest end of the spectrum.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY at the time this permit was issued (February 2005) were:

§ 63.6145 What notifications must I submit and when?

- (a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.
- (b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.
- (c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.
- (d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).
- (e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).
- (f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an -
Application for Permit by:

Mr. H. O. Nuñez, Plant General Manager
Florida Power and Light Company, Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

DEP File No. PSD-FL-338
FP&L Turkey Pt. Unit 5
Miami-Dade County

Enclosed is the Final Permit Number PSD-FL-338 (0250003-006-AC) to construct/install a nominal 1,150 MW combined cycle ("4 on 1") unit and auxiliary equipment at the Turkey Point Fossil Plant near Homestead, Miami-Dade County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.



Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were sent by U.S. Mail or electronic mail before the close of business on 2/8/05 to the person(s) listed:

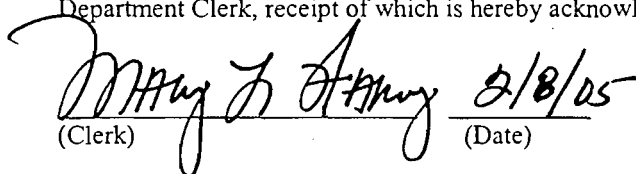
H. O. Nuñez, FPL*
John Gnecco, FPL
Randall LaBauve, FPL*
Barbara Linkiewicz, FPL
Mayor, Miami-Dade County
Mayor, City of Homestead
Mayor, Florida City
John Benjamin, Everglades National Park
Linda Canzanelli, Biscayne National Park

Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Steven L. Palmer, DEP Siting Office
Kevin Neal, DEP SED
Bruce Offord, DEP SED
Paul Darst, Department of Community Affairs
Chair, Miami-Dade County EQCB
H. Patrick Wong, Miami-Dade County DERM
Ken Kosky, P.E., Golder

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date,
pursuant to §120.52, Florida Statutes, with the designated
Department Clerk, receipt of which is hereby acknowledged.

(Clerk)



(Date)

FINAL DETERMINATION
File No. 0250003-006-AC (PSD-FL-338)
FP&L TURKEY POINT POWER PLANT
COMBINED CYCLE UNIT 5

The Department distributed a Public Notice package on May 28, 2004 for the project to construct a natural gas-fired combined cycle unit to be known as Unit 5 – FP&L Turkey Point Power Plant east of Homestead and Florida City and adjacent to Biscayne Bay, Miami-Dade County. The 1150MW project consists of four nominal 170 MW General Electric combustion turbine-electrical generators, four heat recovery steam generators, a 470 MW steam-electrical generator, and a mechanical draft cooling tower. The Public Notice of Intent to Issue was published in the June 10th edition of the Miami Herald.

No requests for public meetings or administrative hearings were received on the Notice of Intent to Issue. An evidentiary hearing was held on September 20-21, 2004 and a Recommended Order was entered on November 18, 2004 to:

“Grant full and final certification to Florida Power & Light Company, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Turkey Point Unit 5, representing a 1150 MW combined cycle unit, as described in the Site Certification Application and the evidence presented at the certification hearing, and subject to the Conditions of Certification.” Final Certification was approved on February 1, 2005.

The Department is required to take final action on the PSD Permit Application and the draft permit within 30 days following Final Certification by the Siting Board. This Final Determination recapitulates all comments and changes since the distribution of the Notice of Intent to Issue PSD Permit on May 28, 2004.

No comments suggesting adverse impacts were received. The comments of the EPA, NPS and FP&L recited or described below (*italics*) followed by the Department’s responses.

1. *EPA’s letter dated July 8, 2004 states, “Condition 9 of the draft PSD permit contains a table of CO emissions limits that are applicable to various operating modes of the four new CTs. The table contains two columns of emission limits. Compliance with the first column of emission limits shall be demonstrated by 3-run stack testing, while compliance with the second column of emission limits shall be demonstrated using a continuous emissions monitoring system (CEMS) with a 24-hour averaging time”.*

The Department agrees with the given description of the table, the limits and how compliance will be demonstrated. But as noted in item 5 below, we reserve use of CEMS for short-term.

2. *EPA’s letter further states, “It is our understanding from conversations with the Florida Department of Environmental Protection (FDEP) that the first column of CO emission limits represents the BACT emission limits (i.e., 4.1 ppm in normal mode, 7.6 ppm with duct burning, etc.) and the second column of CO emission limits contains higher limits that have been proposed to simplify the recordkeeping process (i.e., 8.0 ppm for all modes except power augmentation, etc.). First, we would like to point out that the distinction between the two sets of emission limits described above is not clear in the current draft PSD permit”.*

The 5 ppm value (~4 when corrected to 15% O₂) is the lowest CO limit guaranteed to-date by any combustion turbine manufacturer without requiring installation of additional control equipment such as oxidation catalyst. The 7.6 ppm limit with duct burning and 8 ppm limit for fuel oil use are also the lowest values in permits without oxidation catalyst and represent values roughly equivalent to ambient air quality standards even though measured at the stack.

To simplify recordkeeping, a 24-hour limit of 8 ppm was proposed because it is possible that on a given day, a combined cycle unit will actually operate with the duct burner on at all times. The distinction between the limits is maintained because initial and annual stack tests are required for the three key modes in conjunction with the annual RATA tests for the CEMS.

The remaining concern is that the low guaranteed values for the normal gas-firing case (without high power modes) is not accounted for in the CEMS based limit. To insure that the units cannot possibly be operated at 8 ppm at all times regardless of mode, the Department will set a limit of 6 ppmvd @15% O₂ on a 12 month basis, rolled monthly. This represents an approximate weighted average of emissions based on permitted firing modes. It assumes that the individual units will operate all of the allowable hours in the high power or oil-firing modes and the difference on the normal gas only mode.

The additional requirement will not cause increases or reductions in emissions or cause undue recordkeeping burdens. However the new requirement better represents the long-term, time averaged, emission estimates over all modes of operation consistent with the application.

Based on review of CO data after startup, the Department expects actual average emissions for all modes between 1 to 2 ppm except for the limited power augmentation mode. It is not yet possible to obtain the very low guarantees without installing oxidation catalyst. For reference, emissions during the limited power augmentation mode will likely be between 5 and 9 ppm.

3. EPA's letter states, "If the emission limits are left as they are, this relationship should be better described in the table itself or in a permitting note immediately preceding the table".

The table has been updated to clarify CO emission limits:

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.0, 24-hr
	<u>Oil/Gas</u>	<u>All Modes</u>	<u>NA</u>	<u>NA</u>	<u>6, 12 months</u>

- a. Continuous compliance with the 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
4. *EPA's letter states, "We agree with FDEP that initial compliance with the BACT limits can be determined using a stack test; however, continuous compliance with the BACT emission limits should be demonstrated by use of the CEMS".*

The issue relates to CO. The table now represents a reasonable compromise that provides an additional incentive to the applicant to operate based on initial and annual stack tests. The alternative of separate continuous compliance for each and every mode is feasible but cumbersome. Continuous compliance is demonstrated by the use of CEMS for the 24-hour and 12 month standards.

5. *EPA's letter states, "Condition 19 of the draft PSD permit declares that FDEP "reserves the right" to use data from the CEMS to determine compliance with the short-term CO emission limits. We believe that this condition is not definite enough to enforce the BACT emission limits using CEMS".*

This "right" that was placed in the draft permit provides a powerful incentive to maintain the equipment such that the lowest emissions are achieved. It is not much different than the use of "any credible evidence" in addition to the already stringent stack test and CEM-based BACT emission limits. With the new weighted annual limit for CO, there is an even bigger incentive to comply with the short-term values.

6. *EPA's letter states, "If it is decided that the CEMS will be used to determine compliance with the BACT emission limits, we recommend that the final PSD permit require use of an averaging time shorter than 24 hours. Since there exist short-term CO national ambient air quality standards (NAAQS) with averaging times below 24 hours (i.e., 1-hour and 8-hour standards), we believe that the averaging times should be more consistent with the applicable NAAQS averaging times".*

The range of emission limits for the various modes is 4 to 14 ppm, while expected emissions are 1 to 2 ppm at the stack exit and prior to dilution and dispersion for all but one case. We actually expect emissions of 5 to 9 ppm for the limited power augmentation case. The 1-hour and 8-hour ground level National Ambient Air Quality Standards for CO are 35 and 9 ppm respectively. Even if all of the allowable emissions in a 24-hour period were compressed into a single hour, the ground level concentration would still not exceed 9 ppm. Thus the 24-hour limit is protective of the 1 and 8-hour CO standards. There are no increments for CO that might otherwise reinforce the need for the shorter averaging periods.

7. *EPA states, "any operating limits which were used in the analyses on a per turbine basis should be included in the draft PSD permit on a per turbine basis. The draft PSD permit does contain per turbine limits on the amount of time the CTs can operate in power augmentation mode and while firing fuel oil. However, condition 8(e) of the draft PSD permit contains one aggregate limit (5,702,400 MMBtu) for all four CTs restricting the*

amount of duct firing that is allowed in a year. In order for the BACT analysis to remain valid, the final PSD permit should contain the appropriate duct firing limit on a per turbine basis (i.e., 1,425,600 MMBtu/year). Alternatively, if the applicant wishes to retain the aggregate limit, a revised BACT analysis should be performed (based on the worst case scenario of one CT operating the duct burners all year long) which demonstrates that the outcome of the BACT analysis would remain unchanged".

The point is well taken and the following review was conducted to determine if a further BACT review is needed. Referring to 4 above, the Department has added a long-term limit of 6 ppm CO.

The scenario of firing a single duct burner continuously for the year while hardly firing the others is unrealistic but theoretically possible and needs to be explored. The practical consequence of continuous duct firing is that the given unit must still comply with the BACT NO_x limit of 2 ppm. NO_x emissions will actually be controlled to that level or slightly less by the SCR system.

The CO could theoretically be 7.6 ppm of CO. However if they use the duct burners continuously, they are limited by the new 12 month of 6 ppm (corrected to 15% O₂). GE will guarantee CO emissions from its combustion turbines to 5 ppm uncorrected (~ 4.1 ppm corrected). The duct burner manufacturer has its own guarantee regarding what a duct burner *theoretically adds* to the CO from the combustion turbine.

The Department's analysis of *actual* operating data shows that duct burners do not affect CO emissions in a meaningful manner for F-Class installations. Exhaust gas from the combustion turbine is already at a high temperature, turbulent, and contains a lot of oxygen promoting good CO burnout. The guarantees for the different components have not yet been reconciled into a single low CO guarantee without requiring oxidation catalyst.

Based on the Department's analysis of data from installations with GE F-Class combustion turbines operating in conjunction with duct burners, actual emissions will be in the range of 1 to 2 ppm @15% O₂. The data on the duct burners operating in conjunction with the combustion turbines was included in the Technical Evaluation.

The Department believes that it is not cost-effective to install oxidation catalyst to reduce CO emissions for this part-time mode from 6 to say 1 ppm @15% O₂ when the practical reduction will actually be from the 1 – 2 ppm range to 0.2– 0.4 ppm (assuming roughly 80 percent efficiency). The equipment providers have given their best guarantees short of installing unnecessary oxidation catalyst. This FP&L project was the first to obtain such low guarantees.

Basically, the Department has required FP&L to meet a value lower than the combined guarantees of the combustion turbine provider and the duct burner provider. The data from installations in Florida and the underpinning provided in the Technical Evaluation provide further reasonable assurance that the new long term limit can be achieved and that emissions will in fact be substantially less than permitted.

The Department agrees that FP&L will be able to theoretically fire the duct burner all of the time on one unit and none of the time on others. Although this is a very unlikely situation for economic reasons, the Department believes that the outcome of the BACT analysis would remain unchanged based on the information above.

8. *In the NPS letter dated July 2, 2004, NPS states, "Although FDEP acknowledges that the high power operating modes 'can cause greater uncontrolled NO_x emissions' the proposed permit explicitly exempts FP&L from any emission limits while operating in this mode".*

The Department's BACT determination of 2.0 ppm NO_x limit does apply to all modes except for use of back up ultralow sulfur fuel oil. The Department clarified this issue during discussions with NPS experts on November 24, 2004. After jointly studying the table containing the emissions limits for each power mode, we agreed that the proposed permit does not exempt high power modes from the BACT determination.

9. *In the same letter, the NPS states, "FP&L will reduce their NO_x limit from 2.5 ppm to 2.0 ppm when burning natural gas and from 10.0 ppm to 8.0 ppm when burning oil At the lower NO_x emission rates; we anticipate that visibility impacts at Biscayne NP will also be reduced. Therefore, we do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP".*

The Department agrees with this assessment.

10. *The NPS letter included comments related to the averaging time of the 24-hr NO_x emission limit of 2.0 ppmvd @15% O₂ when burning natural gas. It states, "BACT is an emission limit, and emission limits typically consist of a numerical limit in terms of mass of pollutant per unit time, unit volume and/or per unit of heat input. These emission limits are also typically specified over a prescribed averaging period; due to the inherent variability in emissions and the performance of the control technology, the longer the averaging period, the easier it is to meet a given limit.*

"Although it states in the TEPD top-down analysis that 'The Top emission limit is considered by the Department to be 2.0 ppmvd @ 15% O₂ on a 1-hour average,' FDEP goes on to set FP&L's proposed permit limit for natural gas combustion based upon a 24-hour average, with no explanation provided for the longer averaging period. Therefore, FDEP did not choose the 'top' control technology, nor did it justify proposing a less stringent limit.

"We believe that the 24-hour block averaging periods are much too long when compared to similar combustion turbines meeting the same outlet concentration limits for the one-hour or three-hour averages. The effect of the much longer averaging periods is to reduce the stringency of the limits relative to other permits. For example, Clark County, Nevada, has determined that a 2.0 ppm limit (1-hr average) represents BACT for the Diamond Generating, Ivanpah Energy combustion turbine project. The Virginia Department of Environmental Protection has permitted an identical limit for the CPV Warren County combustion turbine project. Turkey Point should show why it cannot meet a 2.0 ppm limit on a one-hour basis, as it is required of other similar projects".

It is important to note that the NSPS standard for combustion turbines is approximately 108 ppm for F-Class units on a 4 hour basis. The proposed BACT is 2 ppm on a 24-hr basis or only 2 percent of the standard. This is virtually zero for this pollutant in terms of emissions and it is very difficult to achieve lower emissions.

In addition, the NO_x ambient standard is on an annual basis. The 24-hour standard for this source is suitable to limit effects on visibility and ozone formation potential. A one-hour value is achievable but runs the risk that small exceedances that do not have any impacts will be categorized as violations. In any case, the facility would have to compensate quickly when the value exceeds 2 ppm even on a 24-hour average. For example, if a unit were to emit even 10 ppm for four hours, it would have to achieve 0.4 ppm during the preceding and subsequent 20 hours to avoid exceeding the 24-hr limit.

While it is difficult to prove that it is not cost-effective to reduce the averaging time to 1 hour, the Department has a great deal of experience balancing emission limits and averaging times with environmental protection and sensible business operation. This case-by-case BACT determination and combination of limit and averaging time will allow this facility to conduct its business, protect the environment, respond smoothly to operational variations, and dispatch power from other system facilities in an orderly fashion.

The considerations in out-of-state non-attainment areas or sources that influence such non-attainment areas may be somewhat different. The Department does not assert that any of the determinations made in the areas described by NPS are erroneous with respect to limits or averaging time.

In the conversations of November 24, the NPS personnel acknowledged that the Department would make the final BACT determination.

11. *NPS states in its letter dated July 2, 2004, "As referenced in our February 24, 2004 letter to FDEP regarding the emission inventories presented in the FP&L permit application, we reiterate that we would like to know how sources were selected for the inventory, and how emissions from those sources were determined."*

FP&L and Golder referred to their letter dated April 19, 2004 that was in response to the NPS letter dated February 24. The relevant parts follow.

"Cumulative Source Modeling- The detailed stack, operating, and emission data for the facilities with SO₂ and PM₁₀ sources presented in Tables 6-3 and 6-4 are provided in Tables D-1 and D-2 of Appendix D to the Air Construction Permit/PSD Application, Appendix 10.1.5.

"These data were based on information provided from FDEP, available from recent PSD permit applications, Title V permits, and supplemented with current and historical information available within Golder. The air modeling data were obtained from several recently submitted and reviewed air permit applications in which PSD Class I increment or significant impact analyses were performed at the Everglades National Park. These applications include the modifications to U.S. Sugar Corporation's Clewiston Mill (proposed Boiler No. 8, March 2003; Boiler No. 4 and Sugar Refinery, October 2000); Palm Beach

Power Corporation's Cogeneration Facility (April 2002); and FPL's Martin Power Plant Expansion Project, Unit No. 8 (February 2002).

"The major source baseline date for Florida is January 6, 1975 for both SO₂ and PM₁₀ (adopted and incorporated by reference in Rule 62-204.800, F.A.C.). The minor source baseline date for SO₂ and PM₁₀ has been set as December 27, 1977 for the entire State of Florida (Rule 62-204.360(1) and (2), F.A.C.).

"Based on these baseline dates, the baseline and PSD-increment consuming sources of SO₂ and PM₁₀ emissions for the sources in the inventory were developed from the available information discussed previously. The baseline and PSD increment consuming sources are identified in Tables D-1 and D-2 of Appendix A to the Air Construction/PSD Application.

"It should be noted that, although the highest 24-hour average SO₂ concentrations were predicted to exceed 24-hour SO₂ PSD Class I increment for 1990 and 1992, there were no predicted violations of the increment based on the highest, second highest values. Rule 62-272.500 F.A.C. and 40 CFR 52.21(c) support the use of the highest, second highest values when determining compliance with the 24-hour SO₂ PSD Class I increment".

12. *During the telephone discussion of November 24, 2004 NPS advised that the inventory and the modeling for SO₂ Class I Increment Consumption described in the Golder/FP&L response did not, but should have, included minor sources, transportation, and changes in major sources on an actual to actual basis since 1977.*

Turkey Pt. Unit 5 will fire the lowest sulfur fuels available. The project will be the first in Florida to commit to ultralow sulfur fuel oil used as backup fuel to natural gas. The backup fuel actually has a lower sulfur specification than natural gas. NPS advised (see 9 above) they do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP. The Department agrees with NPS.

After receiving clarification from NPS on November 24, 2004 the Department reviewed the issues raised by the NPS. The Department agrees that the analysis for Class I SO₂ Increment Consumption does not comport with the method most recently described by the NPS.

The Department conducted a qualitative and semi-quantitative evaluation and determined that additional modeling, if conducted in the manner described by NPS, will most likely show expansion rather than consumption of SO₂ increment by development since the late 1970's and that the proposed project will not appreciably change that trend. The Department responded to the NPS comments by electronic mail on December 8, 2004. The communication contained most of the following analysis:

The Department obtained information from FP&L regarding actual emissions from the existing Turkey Point units circa 1977. In 2002, emissions were 9,135 tons from Turkey Point Units 1 and 2. During the 1974-1978 timeframe, emissions from Turkey Points Units 1 and 2 were always much higher and averaged 16,558 tons per year. Therefore, the biggest sources (Units 1 and 2) likely to interact with the new project (that will emit 193 tons per year) have expanded increment rather than consumed increment. The summary table of emissions from Turkey Point is shown below.

Emissions of SO₂ from Turkey Point Fossil Plant (1974-78, and 2002)

<u>Year</u>	<u>Tons per year</u>
1974	18,043
1975	18,058
1976	18,028
1977	13,519
1978	15,140
1974-1978	16,558 (average)
2002	9,135
Reduction	~ 7,000

Table 16 from the Technical Evaluation distributed with the Department's Draft PSD Permit lists the largest stationary SO₂ sources in Miami-Dade County and their *actual* emissions.

Table 16. Major Sources of SO₂ in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Florida Power & Light	Turkey Pt. Plant (existing boilers)	9,135 (EPA)
Titan Industries	Tarmac Pennsullo Cement	~ 1,000 (est.)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	231
<i>Florida Power & Light</i>	<i>Turkey Pt. Plant (proposed project)</i>	<i>193</i>
Waste Management	Medley Landfill and Recycling	129
Miami-Dade County WAsD	MDWAsD/Central District WWTP	88

The magnitude of actual large SO₂ emission sources drops off very rapidly after the existing Turkey Point Fossil Plant. Titan/Tarmac Pennsullo Cement will emit closer to 50 TPY (rather than ~1000 TPY) in future years, having modernized their process in 2004. Rinker Cement previously emitted over 1000 TPY of SO₂ and now emits approximately 50 TPY since a modernization project in 2000. General Portland Cement was another significant emitter of SO₂ that closed around 1985.

The 7,000 TPY actual reduction from the collocated Turkey Point Units 1 and 2 and the reductions from reductions in regional cement manufacturing SO₂ emissions would overwhelm any possible effects from the 193 TPY Turkey Point Unit 5.

During the application review phase, FP&L submitted estimates that 2008-2012 SO₂ emissions from Turkey Point Units 1 and 2 will be approximately 5,733 tons per year. The Department does not necessarily agree with or reject these estimates given uncertain fuel prices.

The Department also included in the Technical Evaluation an inventory of the different categories of emissions in Miami-Dade County. The small magnitude of the proposed Turkey Pt. Unit 5 project is obvious.

Table 21. Pollutant Emissions in Miami-Dade County by Source Category (2002)

Source Category	SO ₂	NO _x	CO	PM ₁₀	VOC	NH ₃
Stationary Sources	10,262	12,929	3,891	2,516	1,757	0 (?)
Area Sources	13,266	4,580	78,670	35,438	53,167	2,925
On-Road Mobile	1,989	46,158	492,121	1,230	49,007	1,940
Non-Road Mobile	1,976	19,062	197,091	24,946	15,646	11
Total	27,492	82,729	771,773	64,131	119,578	4,876
<i>Turkey Pt. Unit 5</i>	193	320	450	229	68	~200

Transportation SO₂ emissions are likely lower in recent years than in the baseline years of the late 1970's. Most of the decline is due to the use of 0.05% sulfur fuel oil for transportation versus the previous higher sulfur specifications in gasoline and diesel (e.g. 0.5% sulfur for diesel). Ultralow sulfur fuel oil (0.0015% sulfur) for transportation sources has been mandated so the trend will continue. Any area source/minor source increases would have been very small compared with the reductions at Turkey Point.

The Department issued a permit in 1998 that lead to the actual SO₂ emissions reductions greater than 20,000 TPY from the FP&L Fort Myers Power Plant located 97 km north of the westernmost part of ENP. This expanded increment over the ENP from a generally northwesterly direction. The 1992 natural gas repowering of the FP&L Lauderdale Plant in Dania expanded increment at ENP from a generally northeasterly direction.

Similarly, the FP&L Port Everglades Plant in Broward County and the FP&L Rivera Plant in Palm Beach County use cleaner fuel oil than required and use substantial amounts of natural gas. This probably adds further to any actual to actual analysis of increment expansion.

In conclusion all indications are that SO₂ emissions have been reduced locally and regionally. A modeling effort would likely show improvements rather than degradation related to SO₂ at the ENP since the late 1970's. The Department believes this analysis is sufficient to support issuance of this permit without further detailed analysis.

13. In a letter received July 2, 2004 from FP&L (Barbara Linkiewicz), FPL requested revision of Section III, specific condition 8, b. as follows:

Authorized fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. ~~Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months.~~ The four gas turbines shall fire no more than a cumulative total of 28,028,168 gallons of fuel oil during any calendar year."

Following discussions with the Department and considering EPA's concern regarding the fuel versus hourly limitation for duct burning, FP&L withdrew the request. In this case, the theoretical, but unlikely use of fuel oil for 2000 hours in a single unit and 0 hours in the others might have changed the final BACT.

By electronic communication dated August 15, 2004, FP&L replaced their request in Item 13 with the following:

Authorized Fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any ~~consecutive 12 months~~ calendar year.

The revised request has no practical effect on emissions or the BACT basis for SO₂. The Department will revise the Authorized Fuels condition per the revised request.

14. *In the July 2, 2004 letter, FP&L requests the following change to Section III, Specific Condition 9.f.:*

Each SCR system shall be designed and operated for ammonia slip limit of ~~less~~ no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs.

The Department will revise this emission standard adding the proposed language.

15. *In the July 2, 2004 letter, FPL states:*

"In Section III, pages 14-15, we request the clarifications below. Recognizing that quarterly reports contain all NSPS and State requirements, this clarification combines the quarterly and semi annual reports. The proposed language below also makes Condition 27 consistent with Condition 25a regarding the monitoring period".

Condition 27. ~~Semiannual NSPS Excess Emissions Report. Quarterly Excess Emission Report:~~ ~~In accordance with 40 CFR 60.7 (d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards w~~ Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the permit standards following the NSPS format provided in Appendix XS of this permit. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any daily monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown. An example of the report is provided on Appendix XS. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

~~Condition 28. Quarterly Permit Excess Emissions Report Semiannual NSPS Excess Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7] The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.~~

The Department will adopt these changes with some additional clarification. The reports will include excess emissions related to the BACT determination and any other SIP-based emission limits in addition to the NSPS excess emission reporting requirements.

The other change reflects the recent revision of 40 CFR 60 Subpart GG that defines excess emissions based on CEMS in lieu of water-to-fuel ratio.

16. *On August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. The relevant provision of the rule that stays the effectiveness for units such as proposed at Turkey Point follows:*

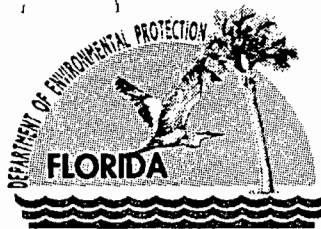
40 CFR 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

The Department has updated relevant parts of the permit and summarized in Appendix YYYY of the permit, the applicable requirements of Subparts A and YYYY in 40 CFR 63.

CONCLUSION

The final action of the Department is to issue the permit with the changes noted above.



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

PERMITTEE:

Florida Power & Light
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:

Scott Stone, Plant General Manager

FP&L Turkey Point Fossil Plant
DEP File No. 0250003-006-AC
Permit No. PSD-FL-338
SIC No. 4911
Expires: December 31, 2008

PROJECT AND LOCATION

This permit authorizes the construction of Unit 5 at the existing FP&L Turkey Point Fossil Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will include four 170 MW gas turbine-electrical generator sets, four heat recovery steam generators, a single 470 MW steam turbine-electrical generator, and a mechanical draft cooling tower. The existing FP&L Turkey Point Fossil Plant is located east of Homestead and Florida City and next to Biscayne Bay in Miami-Dade County, Florida. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

- Section I. General Information
- Section II. Administrative Requirements
- Section III. Emissions Units Specific Conditions
- Section IV. Appendices

Michael G. Cooke for 2/8/05

Michael G. Cooke, Director (Date)
Division of Air Resources Management

"More Protection, Less Process"

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SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The existing Turkey Point Fossil Plant currently consists of two fossil fuel-fired steam electrical generating units and five “Black Start” diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The proposed “4 on 1” combined cycle Unit 5, which will consist of four gas turbines (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. New combined cycle Unit 5 will have a total generating capacity of approximately 1150 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
005	Unit 5A gas turbine (170 MW) with supplementary-fired heat recovery steam generator
006	Unit 5B gas turbine (170 MW) with supplementary-fired heat recovery steam generator
007	Unit 5C gas turbine (170 MW) with supplementary-fired heat recovery steam generator
008	Unit 5D gas turbine (170 MW) with supplementary-fired heat recovery steam generator
009	One distillate fuel oil storage tank for Unit 5 gas turbines
010	Mechanical draft cooling tower for Unit 5

Note: FPL Turkey Point Fossil Plant Unit 5 consists of four gas combustion turbine-electrical generator sets (Units 5A-5D), four supplementary gas-fired heat recovery steam generators (HRSGs), and a single steam turbine-electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY of this permit).

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as “attainment,” “maintenance,” or “unclassifiable” for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a “fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input”, which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

SECTION I. GENERAL INFORMATION

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Miami-Dade County Department of Environmental Resources Management (DERM), Air Quality Management, 33 Southwest 2nd Avenue, Suite 900, Miami, Florida 33130-1540.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix CF. Citation Format and Definitions

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

Appendix YYYY. NESHAP Requirements for Gas Turbines from 40 CFR 63, Subpart YYYY

Appendix XS. Semiannual NSPS Excess Emissions Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on November 14, 2003;
- Department PSD Application Sufficiency comments dated January 2, 2004;
- Environmental Protection Agency Region 4 letter dated January 15, 2004;
- Department of Interior/NPS letter dated February 27, 2004;
- Sufficiency Responses received March 1, 2004;
- Letter dated April 19, 2004 from Golder in response to NPS letter dated February 27, 2004;
- Draft permit package issued on May 28, 2004;
- Letter dated July 1, 2004 from FP&L regarding draft permit;
- Letter dated July 2, 2004 from National Park Service regarding draft permit;
- Letter dated July 8, 2004 from EPA regarding draft permit;
- Final Certification by the Power Plant Siting Board on February 1, 2005; and
- Final Determination on PSD Permit distributed concurrently with Final PSD Permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]
4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]
6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]
7. Title V Permit Revision: The permittee shall submit an application for a revised Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

This section of the permit addresses the following emissions units.

Emissions Units 005, 006, 007, 008

Description: Emissions units 005, 006, 007, and 008 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate supplementary-fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a generating capacity of 470 MW. The total generating capacity of the "4 on 1" combined cycle unit is approximately 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, PM/PM₁₀, SAM, SO₂ and VOC. Dry Low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system further reduces NO_x emissions.

Stack Parameters: Each HRSG has a stack at least 130 feet tall with a nominal diameter of 19 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics:

<u>Fuel</u>	<u>Heat Input Rate (LHV)</u>	<u>Compressor Inlet Temp.</u>	<u>Exhaust Temp., °F</u>	<u>Flow Rate ACFM</u>
Gas	1,608 MMBtu/hour	59° F	202° F	1,023,872
Oil	1,830 MMBtu/hour	59° F	295° F	1,224,407

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. **BACT Determinations:** Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfuric acid mist (SAM), sulfur dioxide (SO₂) and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
2. **NSPS Requirements:** The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]
- 2.a. **NESHAP Requirements:** The combustion turbines are subject to 40 CFR 63, Subpart YYYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYYY until EPA takes final action to require compliance and publishes a document in the Federal Register.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the SpeedtronicTM automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to 290 °F before combustion to increase overall unit efficiency. This will be accomplished by feedwater heat exchangers. [Application; Design]
4. Gas Turbine NO_x Controls
 - a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_x emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH₃) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_x and NH₃ emissions.
 - d. *Ammonia Storage*: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Design; Rule 62-212.400(BACT), F.A.C.]
5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (5A-5D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_x/MMBtu. {Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.} [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,608 MMBtu per hour when firing natural gas and 1,830 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods

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of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]
8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
 - a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
 - b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any calendar year.
 - c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
 - d. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."
 - e. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.
 - f. *High Power Modes (Peaking and Power Augmentation)*: When firing natural gas and only while practicing duct firing, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. When firing natural gas and only while practicing duct firing, steam may be injected into each gas turbine expansion section to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation," the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total hours of power augmentation plus the total hours of peaking shall not exceed 400 hours per gas turbine during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

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EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
	CT & DB & PA	NA	NA	14.0, 24-hr	
	Oil/Gas	All Modes	NA	NA	6, 12-month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- a. Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
- b. Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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- c. The sulfur fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard and Section 24.41.1 of the Miami-Dade County Code shall be demonstrated by conducting tests in accordance with EPA Method 9.
- d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section. Compliance with the SO₂ BACT also insures compliance with Section 24.41.3 of the Miami-Dade County Code.
- e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- f. Each SCR system shall be designed and operated for ammonia slip limit of no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "PK" means peaking, "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

[Rule 62-212.400(BACT), F.A.C.]

- 10. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. This is not considered a separate mode of operation with respect to emission limits. When operating in this manner, each unit shall comply with the respective standards given in Condition 9 for each mode of operation indicated therein. [Application]
- 11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. *{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da}* [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

- 12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]
14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]
15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A “documented malfunction” means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.
 - a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold “startup of the steam turbine system” is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*
 - b. For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.
 - c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. “Cold startup of a gas turbine/HRSG system” is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.
 - d. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]
16. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer’s specifications. A “major tuning session” would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

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EMISSIONS PERFORMANCE TESTING

17. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "<http://www.epa.gov/ttn/emc/ctm.html>". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

18. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_x, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Stack test data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_x mass rate emissions standards. CO and NO_x emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]
19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_x limits for each method of operation given in Condition 9 above. [Rule 62-212.400 (BACT), F.A.C.]
20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

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{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

21. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_x from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_x standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
- CO Monitors. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - NO_x Monitors. Each NO_x monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NO_x monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - Diluent Monitors. The oxygen (O₂) or carbon dioxide (CO₂) content of the flue gas shall be monitored at the location where CO and NO_x are monitored to correct the measured emissions rates to 15% oxygen. If a CO₂ monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
 - 1-Hour Block Averages. Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0%

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moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_x as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

- e. *24-hour Block Averages:* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_x emissions depending on the use of alternate methods of operation}.* [Rule 62-212.400(BACT), F.A.C.]
- f. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- g. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

- 22. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_x emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_x monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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RECORDS AND REPORTS

23. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
24. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
25. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.
- a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.
 - b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.
- The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]
26. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

27. Quarterly Excess Emission Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards (BACT, SIP, NSPS) following the NSPS format provided in Appendix XS of this permit.

For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NO_x concentration exceeds the NSPS NO_x emission standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown.

Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7, and 60.334(j)(1)]

28. Semiannual NSPS Excess Emissions Report: The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
009	One distillate fuel oil storage tank for Unit 5 gas turbines (approximately 4.2 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.; and Section 24.41.6, Miami-Dade County Code.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 4.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 5 gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. COOLING TOWER (EU 010)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
010	22-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 22-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM₁₀ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM₁₀ per year. Actual emissions are expected be lower than these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

SECTION IV. APPENDICES

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SECTION IV. APPENDIX A
NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

- § 60.1 Applicability.
- § 60.2 Definitions.
- § 60.3 Units and abbreviations.
- § 60.4 Address.
- § 60.5 Determination of construction or modification.
- § 60.6 Review of plans.
- § 60.7 Notification and Record Keeping.
- § 60.8 Performance Tests.
- § 60.9 Availability of information.
- § 60.10 State Authority.
- § 60.11 Compliance with Standards and Maintenance Requirements.
- § 60.12 Circumvention.
- § 60.13 Monitoring Requirements.
- § 60.14 Modification.
- § 60.15 Reconstruction.
- § 60.16 Priority List.
- § 60.17 Incorporations by Reference.
- § 60.18 General Control Device Requirements.
- § 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

SECTION IV. APPENDIX BD

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12 month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.
- Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂.
- The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
- The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
- Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

SECTION IV. APPENDIX BD
FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

A. A. Linero 2/1/05

Recommended By:

Approved By:

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Michael G. Cooke

Michael G. Cooke, Director
Division of Air Resources Management

2/8/05

Date

2/8/05

Date

SECTION IV. APPENDIX CF
CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001" identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

- (119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.
- (179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
- (258) Shutdown - The cessation of the operation of an emissions unit for any purpose.
- (275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 5 gas turbine/HRSG systems, which are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

“Duct burner” means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

“Electric utility combined cycle gas turbine” means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Electric utility steam generating unit” means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Fossil fuel” means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

“Gross output” means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

“Potential electrical output capacity” is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

“Steam generating unit” means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM₁₀ emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil ($\leq 0.05\%$ sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO_2 emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NO_x) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})] / (O_{sg} \times h) \quad (\text{Equation 1})$$

Where:

- E = Emission rate of NO_x from the duct burner, ng/J (lb/Mwh) gross output
- C_{sg} = Average hourly concentration of NO_x exiting the steam generating unit, ng/dscm (lb/dscf)
- C_{te} = Average hourly concentration of NO_x in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
- Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
- Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
- O_{sg} = Average hourly gross energy output from steam generating unit, J (Mwh)
- h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_x concentrations (C_{sg} and C_{te}). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Q_{sg} and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1-hour runs) for the initial performance tests. Thereafter, compliance with the NO_x limits established in the PSD permit shall demonstrate compliance with NO_x limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

SECTION IV. APPENDIX Da

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_x standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_x emission rate when demonstrating compliance with the NO_x standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
 - a. Have access to and copy and records that must be kept under the conditions of the permit;
 - b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
 - c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
 - a. A description of and cause of non-compliance; and
 - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
 - a. Determination of Best Available Control Technology (X);
 - b. Determination of Prevention of Significant Deterioration (X);
 - c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
 - d. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
 - a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - c. Records of monitoring information shall include:
 - 1) The date, exact place, and time of sampling or measurements;
 - 2) The person responsible for performing the sampling or measurements;
 - 3) The dates analyses were performed;
 - 4) The person responsible for performing the analyses;
 - 5) The analytical techniques or methods used; and
 - 6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The Unit 5 gas turbines are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.330 Applicability and Designation of Affected Facility.

Each Unit 5 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

- (a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.
- (b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.
- (d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.
- (g) ISO standard day conditions mean 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.
- (h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.
- (i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.
- (j) Base load means the load level at which a gas turbine is normally operated.
- (q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_x) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

$$\text{STD} = 0.0075 \frac{(14.4)}{Y} + F$$

Where:

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NO_x contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NO_x emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NO_x standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil ($\leq 0.05\%$ sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_x standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NO_x emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_x) for each run using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) (\text{Pr}/\text{Po})^{0.5} e^{19(\text{Ho}-0.00633)} (288^\circ\text{K}/\text{Ta})^{1.53}$$

Where:

- NO_x = Emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, volume percent
- NO_{x0} = Observed NO_x concentration, ppm by volume
- Pr = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
- Po = Observed combustor inlet absolute pressure at test, mm Hg
- Ho = Observed humidity of ambient air, g H_2O /g air
- e = Transcendental constant, 2.718
- Ta = Ambient temperature, $^\circ\text{K}$

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_x monitor shall be used to demonstrate compliance with the specified NO_x limits. The permittee is allowed to make the initial compliance demonstration for NO_x emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_x monitor. The permittee is not required to have the NO_x monitor continuously correct NO_x emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]
12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
 - a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
 - b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
 - c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.[Rule 62-297.310(4), F.A.C.]
14. Determination of Process Variables
 - a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
 - b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.[Rule 62-297.310(5), F.A.C.]
15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.
16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]
17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]
18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

- 1) The type, location, and designation of the emissions unit tested.
- 2) The facility at which the emissions unit is located.
- 3) The owner or operator of the emissions unit.
- 4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
- 5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
- 6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
- 7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
- 8) The date, starting time and duration of each sampling run.
- 9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
- 10) The number of points sampled and configuration and location of the sampling plane.
- 11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
- 12) The type, manufacturer and configuration of the sampling equipment used.
- 13) Data related to the required calibration of the test equipment.
- 14) Data on the identification, processing and weights of all filters used.
- 15) Data on the types and amounts of any chemical solutions used.
- 16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
- 17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
- 18) All measured and calculated data required to be determined by each applicable test procedure for each run.
- 19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
- 20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
- 21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION IV. APPENDIX XS
SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant (*Circle One*): SO₂ NO_x TRS H₂S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ¹: _____

Emission data summary ¹	CMS performance summary ¹
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. Total duration of excess emissions x (100) / [Total source operating time] % ²	1. CMS downtime in reporting period due to: a. Monitor equipment malfunctions b. Non-Monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CMS Downtime 3. [Total CMS Downtime] x (100) / [Total source operating time] % ²

¹ For opacity, record all times in minutes. For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ Date: _____

Title: _____

SECTION IV. APPENDIX YYYY
NESHAP REQUIREMENTS FOR GAS TURBINES

Applicability of NESHAP Subpart YYYY

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O₂). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

According to General Electric, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposed to meet the limit proposed in YYYY of 91 ppbvd based on the performance of the GE 7FA unit. The very low CO and VOC emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_x combustion technology employed by these units ensure that formaldehyde emissions will be at the lowest end of the spectrum.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY at the time this permit was issued (February 2005) were:

§ 63.6145 What notifications must I submit and when?

- (a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.
- (b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.
- (c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.
- (d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).
- (e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).
- (f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an -
Application for Permit by:

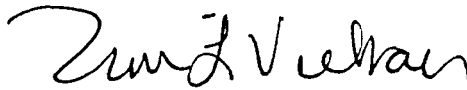
Mr. H. O. Nuñez, Plant General Manager
Florida Power and Light Company, Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

DEP File No. PSD-FL-338
FP&L Turkey Pt. Unit 5
Miami-Dade County

Enclosed is the Final Permit Number PSD-FL-338 (0250003-006-AC) to construct/install a nominal 1,150 MW combined cycle ("4 on 1") unit and auxiliary equipment at the Turkey Point Fossil Plant near Homestead, Miami-Dade County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.



Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

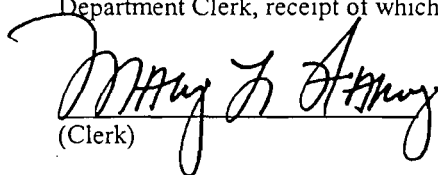
The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were sent by U.S. Mail or electronic mail before the close of business on 2/8/05 to the person(s) listed:

H. O. Nuñez, FPL*
John Gnecco, FPL
Randall LaBauve, FPL*
Barbara Linkiewicz, FPL
Mayor, Miami-Dade County
Mayor, City of Homestead
Mayor, Florida City
John Benjamin, Everglades National Park
Linda Canzanelli, Biscayne National Park

Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Steven L. Palmer, DEP Siting Office
Kevin Neal, DEP SED
Bruce Offord, DEP SED
Paul Darst, Department of Community Affairs
Chair, Miami-Dade County EQCB
H. Patrick Wong, Miami-Dade County DERM
Ken Kosky, P.E., Golder

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

 2/8/05
(Clerk) (Date)

FINAL DETERMINATION
File No. 0250003-006-AC (PSD-FL-338)
FP&L TURKEY POINT POWER PLANT
COMBINED CYCLE UNIT 5

The Department distributed a Public Notice package on May 28, 2004 for the project to construct a natural gas-fired combined cycle unit to be known as Unit 5 – FP&L Turkey Point Power Plant east of Homestead and Florida City and adjacent to Biscayne Bay, Miami-Dade County. The 1150MW project consists of four nominal 170 MW General Electric combustion turbine-electrical generators, four heat recovery steam generators, a 470 MW steam-electrical generator, and a mechanical draft cooling tower. The Public Notice of Intent to Issue was published in the June 10th edition of the Miami Herald.

No requests for public meetings or administrative hearings were received on the Notice of Intent to Issue. An evidentiary hearing was held on September 20-21, 2004 and a Recommended Order was entered on November 18, 2004 to:

“Grant full and final certification to Florida Power & Light Company, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Turkey Point Unit 5, representing a 1150 MW combined cycle unit, as described in the Site Certification Application and the evidence presented at the certification hearing, and subject to the Conditions of Certification.” Final Certification was approved on February 1, 2005.

The Department is required to take final action on the PSD Permit Application and the draft permit within 30 days following Final Certification by the Siting Board. This Final Determination recapitulates all comments and changes since the distribution of the Notice of Intent to Issue PSD Permit on May 28, 2004.

No comments suggesting adverse impacts were received. The comments of the EPA, NPS and FP&L recited or described below (*italics*) followed by the Department’s responses.

1. *EPA’s letter dated July 8, 2004 states, “Condition 9 of the draft PSD permit contains a table of CO emissions limits that are applicable to various operating modes of the four new CTs. The table contains two columns of emission limits. Compliance with the first column of emission limits shall be demonstrated by 3-run stack testing, while compliance with the second column of emission limits shall be demonstrated using a continuous emissions monitoring system (CEMS) with a 24-hour averaging time”.*

The Department agrees with the given description of the table, the limits and how compliance will be demonstrated. But as noted in item 5 below, we reserve use of CEMS for short-term.

2. *EPA’s letter further states, “It is our understanding from conversations with the Florida Department of Environmental Protection (FDEP) that the first column of CO emission limits represents the BACT emission limits (i.e., 4.1 ppm in normal mode, 7.6 ppm with duct burning, etc.) and the second column of CO emission limits contains higher limits that have been proposed to simplify the recordkeeping process (i.e., 8.0 ppm for all modes except power augmentation, etc.). First, we would like to point out that the distinction between the two sets of emission limits described above is not clear in the current draft PSD permit”.*

The 5 ppm value (~4 when corrected to 15% O₂) is the lowest CO limit guaranteed to-date by any combustion turbine manufacturer without requiring installation of additional control equipment such as oxidation catalyst. The 7.6 ppm limit with duct burning and 8 ppm limit for fuel oil use are also the lowest values in permits without oxidation catalyst and represent values roughly equivalent to ambient air quality standards even though measured at the stack.

To simplify recordkeeping, a 24-hour limit of 8 ppm was proposed because it is possible that on a given day, a combined cycle unit will actually operate with the duct burner on at all times. The distinction between the limits is maintained because initial and annual stack tests are required for the three key modes in conjunction with the annual RATA tests for the CEMS.

The remaining concern is that the low guaranteed values for the normal gas-firing case (without high power modes) is not accounted for in the CEMS based limit. To insure that the units cannot possibly be operated at 8 ppm at all times regardless of mode, the Department will set a limit of 6 ppmvd @15% O₂ on a 12 month basis, rolled monthly. This represents an approximate weighted average of emissions based on permitted firing modes. It assumes that the individual units will operate all of the allowable hours in the high power or oil-firing modes and the difference on the normal gas only mode.

The additional requirement will not cause increases or reductions in emissions or cause undue recordkeeping burdens. However the new requirement better represents the long-term, time averaged, emission estimates over all modes of operation consistent with the application.

Based on review of CO data after startup, the Department expects actual average emissions for all modes between 1 to 2 ppm except for the limited power augmentation mode. It is not yet possible to obtain the very low guarantees without installing oxidation catalyst. For reference, emissions during the limited power augmentation mode will likely be between 5 and 9 ppm.

3. *EPA's letter states, "If the emission limits are left as they are, this relationship should be better described in the table itself or in a permitting note immediately preceding the table".*

The table has been updated to clarify CO emission limits:

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.0, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12 months

- a. Continuous compliance with the 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
4. *EPA's letter states, "We agree with FDEP that initial compliance with the BACT limits can be determined using a stack test; however, continuous compliance with the BACT emission limits should be demonstrated by use of the CEMS".*

The issue relates to CO. The table now represents a reasonable compromise that provides an additional incentive to the applicant to operate based on initial and annual stack tests. The alternative of separate continuous compliance for each and every mode is feasible but cumbersome. Continuous compliance is demonstrated by the use of CEMS for the 24-hour and 12 month standards.

5. *EPA's letter states, "Condition 19 of the draft PSD permit declares that FDEP "reserves the right" to use data from the CEMS to determine compliance with the short-term CO emission limits. We believe that this condition is not definite enough to enforce the BACT emission limits using CEMS".*

This "right" that was placed in the draft permit provides a powerful incentive to maintain the equipment such that the lowest emissions are achieved. It is not much different than the use of "any credible evidence" in addition to the already stringent stack test and CEM-based BACT emission limits. With the new weighted annual limit for CO, there is an even bigger incentive to comply with the short-term values.

6. *EPA's letter states, "If it is decided that the CEMS will be used to determine compliance with the BACT emission limits, we recommend that the final PSD permit require use of an averaging time shorter than 24 hours. Since there exist short-term CO national ambient air quality standards (NAAQS) with averaging times below 24 hours (i.e., 1-hour and 8-hour standards), we believe that the averaging times should be more consistent with the applicable NAAQS averaging times".*

The range of emission limits for the various modes is 4 to 14 ppm, while expected emissions are 1 to 2 ppm at the stack exit and prior to dilution and dispersion for all but one case. We actually expect emissions of 5 to 9 ppm for the limited power augmentation case. The 1-hour and 8-hour ground level National Ambient Air Quality Standards for CO are 35 and 9 ppm respectively. Even if all of the allowable emissions in a 24-hour period were compressed into a single hour, the ground level concentration would still not exceed 9 ppm. Thus the 24-hour limit is protective of the 1 and 8-hour CO standards. There are no increments for CO that might otherwise reinforce the need for the shorter averaging periods.

7. *EPA states, "any operating limits which were used in the analyses on a per turbine basis should be included in the draft PSD permit on a per turbine basis. The draft PSD permit does contain per turbine limits on the amount of time the CTs can operate in power augmentation mode and while firing fuel oil. However, condition 8(e) of the draft PSD permit contains one aggregate limit (5,702,400 MMBtu) for all four CTs restricting the*

amount of duct firing that is allowed in a year. In order for the BACT analysis to remain valid, the final PSD permit should contain the appropriate duct firing limit on a per turbine basis (i.e., 1,425,600 MMBtu/year). Alternatively, if the applicant wishes to retain the aggregate limit, a revised BACT analysis should be performed (based on the worst case scenario of one CT operating the duct burners all year long) which demonstrates that the outcome of the BACT analysis would remain unchanged”.

The point is well taken and the following review was conducted to determine if a further BACT review is needed. Referring to 4 above, the Department has added a long-term limit of 6 ppm CO.

The scenario of firing a single duct burner continuously for the year while hardly firing the others is unrealistic but theoretically possible and needs to be explored. The practical consequence of continuous duct firing is that the given unit must still comply with the BACT NO_x limit of 2 ppm. NO_x emissions will actually be controlled to that level or slightly less by the SCR system.

The CO could theoretically be 7.6 ppm of CO. However if they use the duct burners continuously, they are limited by the new 12 month of 6 ppm (corrected to 15% O₂). GE will guarantee CO emissions from its combustion turbines to 5 ppm uncorrected (~ 4.1 ppm corrected). The duct burner manufacturer has its own guarantee regarding what a duct burner *theoretically adds* to the CO from the combustion turbine.

The Department's analysis of *actual* operating data shows that duct burners do not affect CO emissions in a meaningful manner for F-Class installations. Exhaust gas from the combustion turbine is already at a high temperature, turbulent, and contains a lot of oxygen promoting good CO burnout. The guarantees for the different components have not yet been reconciled into a single low CO guarantee without requiring oxidation catalyst.

Based on the Department's analysis of data from installations with GE F-Class combustion turbines operating in conjunction with duct burners, actual emissions will be in the range of 1 to 2 ppm @15% O₂. The data on the duct burners operating in conjunction with the combustion turbines was included in the Technical Evaluation.

The Department believes that it is not cost-effective to install oxidation catalyst to reduce CO emissions for this part-time mode from 6 to say 1 ppm @15% O₂ when the practical reduction will actually be from the 1 – 2 ppm range to 0.2– 0.4 ppm (assuming roughly 80 percent efficiency). The equipment providers have given their best guarantees short of installing unnecessary oxidation catalyst. This FP&L project was the first to obtain such low guarantees.

Basically, the Department has required FP&L to meet a value lower than the combined guarantees of the combustion turbine provider and the duct burner provider. The data from installations in Florida and the underpinning provided in the Technical Evaluation provide further reasonable assurance that the new long term limit can be achieved and that emissions will in fact be substantially less than permitted.

The Department agrees that FP&L will be able to theoretically fire the duct burner all of the time on one unit and none of the time on others. Although this is a very unlikely situation for economic reasons, the Department believes that the outcome of the BACT analysis would remain unchanged based on the information above.

8. *In the NPS letter dated July 2, 2004, NPS states, "Although FDEP acknowledges that the high power operating modes 'can cause greater uncontrolled NO_x emissions' the proposed permit explicitly exempts FP&L from any emission limits while operating in this mode".*

The Department's BACT determination of 2.0 ppm NO_x limit does apply to all modes except for use of back up ultralow sulfur fuel oil. The Department clarified this issue during discussions with NPS experts on November 24, 2004. After jointly studying the table containing the emissions limits for each power mode, we agreed that the proposed permit does not exempt high power modes from the BACT determination.

9. *In the same letter, the NPS states, "FP&L will reduce their NO_x limit from 2.5 ppm to 2.0 ppm when burning natural gas and from 10.0 ppm to 8.0 ppm when burning oil At the lower NO_x emission rates; we anticipate that visibility impacts at Biscayne NP will also be reduced. Therefore, we do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP".*

The Department agrees with this assessment.

10. *The NPS letter included comments related to the averaging time of the 24-hr NO_x emission limit of 2.0 ppmvd @15% O₂ when burning natural gas. It states, "BACT is an emission limit, and emission limits typically consist of a numerical limit in terms of mass of pollutant per unit time, unit volume and/or per unit of heat input. These emission limits are also typically specified over a prescribed averaging period; due to the inherent variability in emissions and the performance of the control technology, the longer the averaging period, the easier it is to meet a given limit.*

"Although it states in the TEPD top-down analysis that 'The Top emission limit is considered by the Department to be 2.0 ppmvd @ 15% O₂ on a 1-hour average,' FDEP goes on to set FP&L's proposed permit limit for natural gas combustion based upon a 24-hour average, with no explanation provided for the longer averaging period. Therefore, FDEP did not choose the 'top' control technology, nor did it justify proposing a less stringent limit.

"We believe that the 24-hour block averaging periods are much too long when compared to similar combustion turbines meeting the same outlet concentration limits for the one-hour or three-hour averages. The effect of the much longer averaging periods is to reduce the stringency of the limits relative to other permits. For example, Clark County, Nevada, has determined that a 2.0 ppm limit (1-hr average) represents BACT for the Diamond Generating, Ivanpah Energy combustion turbine project. The Virginia Department of Environmental Protection has permitted an identical limit for the CPV Warren County combustion turbine project. Turkey Point should show why it cannot meet a 2.0 ppm limit on a one-hour basis, as it is required of other similar projects".

It is important to note that the NSPS standard for combustion turbines is approximately 108 ppm for F-Class units on a 4 hour basis. The proposed BACT is 2 ppm on a 24-hr basis or only 2 percent of the standard. This is virtually zero for this pollutant in terms of emissions and it is very difficult to achieve lower emissions.

In addition, the NO_x ambient standard is on an annual basis. The 24-hour standard for this source is suitable to limit effects on visibility and ozone formation potential. A one-hour value is achievable but runs the risk that small exceedances that do not have any impacts will be categorized as violations. In any case, the facility would have to compensate quickly when the value exceeds 2 ppm even on a 24-hour average. For example, if a unit were to emit even 10 ppm for four hours, it would have to achieve 0.4 ppm during the preceding and subsequent 20 hours to avoid exceeding the 24-hr limit.

While it is difficult to prove that it is not cost-effective to reduce the averaging time to 1 hour, the Department has a great deal of experience balancing emission limits and averaging times with environmental protection and sensible business operation. This case-by-case BACT determination and combination of limit and averaging time will allow this facility to conduct its business, protect the environment, respond smoothly to operational variations, and dispatch power from other system facilities in an orderly fashion.

The considerations in out-of-state non-attainment areas or sources that influence such non-attainment areas may be somewhat different. The Department does not assert that any of the determinations made in the areas described by NPS are erroneous with respect to limits or averaging time.

In the conversations of November 24, the NPS personnel acknowledged that the Department would make the final BACT determination.

11. *NPS states in its letter dated July 2, 2004, "As referenced in our February 24, 2004 letter to FDEP regarding the emission inventories presented in the FP&L permit application, we reiterate that we would like to know how sources were selected for the inventory, and how emissions from those sources were determined."*

FP&L and Golder referred to their letter dated April 19, 2004 that was in response to the NPS letter dated February 24. The relevant parts follow.

"Cumulative Source Modeling- The detailed stack, operating, and emission data for the facilities with SO₂ and PM₁₀ sources presented in Tables 6-3 and 6-4 are provided in Tables D-1 and D-2 of Appendix D to the Air Construction Permit/PSD Application, Appendix 10.1.5.

"These data were based on information provided from FDEP, available from recent PSD permit applications, Title V permits, and supplemented with current and historical information available within Golder. The air modeling data were obtained from several recently submitted and reviewed air permit applications in which PSD Class I increment or significant impact analyses were performed at the Everglades National Park. These applications include the modifications to U.S. Sugar Corporation's Clewiston Mill (proposed Boiler No. 8, March 2003; Boiler No. 4 and Sugar Refinery, October 2000); Palm Beach

Power Corporation's Cogeneration Facility (April 2002); and FPL's Martin Power Plant Expansion Project, Unit No. 8 (February 2002).

"The major source baseline date for Florida is January 6, 1975 for both SO₂ and PM₁₀ (adopted and incorporated by reference in Rule 62-204.800, F.A.C.). The minor source baseline date for SO₂ and PM₁₀ has been set as December 27, 1977 for the entire State of Florida (Rule 62-204.360(1) and (2), F.A.C.).

"Based on these baseline dates, the baseline and PSD-increment consuming sources of SO₂ and PM₁₀ emissions for the sources in the inventory were developed from the available information discussed previously. The baseline and PSD increment consuming sources are identified in Tables D-1 and D-2 of Appendix A to the Air Construction/PSD Application.

"It should be noted that, although the highest 24-hour average SO₂ concentrations were predicted to exceed 24-hour SO₂ PSD Class I increment for 1990 and 1992, there were no predicted violations of the increment based on the highest, second highest values. Rule 62-272.500 F.A.C. and 40 CFR 52.21(c) support the use of the highest, second highest values when determining compliance with the 24-hour SO₂ PSD Class I increment".

12. *During the telephone discussion of November 24, 2004 NPS advised that the inventory and the modeling for SO₂ Class I Increment Consumption described in the Golder/FP&L response did not, but should have, included minor sources, transportation, and changes in major sources on an actual to actual basis since 1977.*

Turkey Pt. Unit 5 will fire the lowest sulfur fuels available. The project will be the first in Florida to commit to ultralow sulfur fuel oil used as backup fuel to natural gas. The backup fuel actually has a lower sulfur specification than natural gas. NPS advised (see 9 above) they do not anticipate that emissions from the proposed Turkey Point Power Plant modifications will impact sensitive resources at Everglades NP or Biscayne NP. The Department agrees with NPS.

After receiving clarification from NPS on November 24, 2004 the Department reviewed the issues raised by the NPS. The Department agrees that the analysis for Class I SO₂ Increment Consumption does not comport with the method most recently described by the NPS.

The Department conducted a qualitative and semi-quantitative evaluation and determined that additional modeling, if conducted in the manner described by NPS, will most likely show expansion rather than consumption of SO₂ increment by development since the late 1970's and that the proposed project will not appreciably change that trend. The Department responded to the NPS comments by electronic mail on December 8, 2004. The communication contained most of the following analysis:

The Department obtained information from FP&L regarding actual emissions from the existing Turkey Point units circa 1977. In 2002, emissions were 9,135 tons from Turkey Point Units 1 and 2. During the 1974-1978 timeframe, emissions from Turkey Points Units 1 and 2 were always much higher and averaged 16,558 tons per year. Therefore, the biggest sources (Units 1 and 2) likely to interact with the new project (that will emit 193 tons per year) have expanded increment rather than consumed increment. The summary table of emissions from Turkey Point is shown below.

Emissions of SO₂ from Turkey Point Fossil Plant (1974-78, and 2002)

<u>Year</u>	<u>Tons per year</u>
1974	18,043
1975	18,058
1976	18,028
1977	13,519
1978	15,140
1974-1978	16,558 (average)
2002	9,135
Reduction	~ 7,000

Table 16 from the Technical Evaluation distributed with the Department's Draft PSD Permit lists the largest stationary SO₂ sources in Miami-Dade County and their *actual* emissions.

Table 16. Major Sources of SO₂ in Miami-Dade County (2002)

<u>Owner</u>	<u>Site Name</u>	<u>Tons per year</u>
Florida Power & Light	Turkey Pt. Plant (existing boilers)	9,135 (EPA)
Titan Industries	Tarmac Pennsucco Cement	~ 1,000 (est.)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	231
<i>Florida Power & Light</i>	<i>Turkey Pt. Plant (proposed project)</i>	<i>193</i>
Waste Management	Medley Landfill and Recycling	129
Miami-Dade County WASD	MDWASD/Central District WWTP	88

The magnitude of actual large SO₂ emission sources drops off very rapidly after the existing Turkey Point Fossil Plant. Titan/Tarmac Pennsucco Cement will emit closer to 50 TPY (rather than ~1000 TPY) in future years, having modernized their process in 2004. Rinker Cement previously emitted over 1000 TPY of SO₂ and now emits approximately 50 TPY since a modernization project in 2000. General Portland Cement was another significant emitter of SO₂ that closed around 1985.

The 7,000 TPY actual reduction from the collocated Turkey Point Units 1 and 2 and the reductions from reductions in regional cement manufacturing SO₂ emissions would overwhelm any possible effects from the 193 TPY Turkey Point Unit 5.

During the application review phase, FP&L submitted estimates that 2008-2012 SO₂ emissions from Turkey Point Units 1 and 2 will be approximately 5,733 tons per year. The Department does not necessarily agree with or reject these estimates given uncertain fuel prices.

The Department also included in the Technical Evaluation an inventory of the different categories of emissions in Miami-Dade County. The small magnitude of the proposed Turkey Pt. Unit 5 project is obvious.

Table 21. Pollutant Emissions in Miami-Dade County by Source Category (2002)

Source Category	SO ₂	NO _x	CO	PM ₁₀	VOC	NH ₃
Stationary Sources	10,262	12,929	3,891	2,516	1,757	0 (?)
Area Sources	13,266	4,580	78,670	35,438	53,167	2,925
On-Road Mobile	1,989	46,158	492,121	1,230	49,007	1,940
Non-Road Mobile	1,976	19,062	197,091	24,946	15,646	11
Total	27,492	82,729	771,773	64,131	119,578	4,876
<i>Turkey Pt. Unit 5</i>	193	320	450	229	68	~200

Transportation SO₂ emissions are likely lower in recent years than in the baseline years of the late 1970's. Most of the decline is due to the use of 0.05% sulfur fuel oil for transportation versus the previous higher sulfur specifications in gasoline and diesel (e.g. 0.5% sulfur for diesel). Ultralow sulfur fuel oil (0.0015% sulfur) for transportation sources has been mandated so the trend will continue. Any area source/minor source increases would have been very small compared with the reductions at Turkey Point.

The Department issued a permit in 1998 that lead to the actual SO₂ emissions reductions greater than 20,000 TPY from the FP&L Fort Myers Power Plant located 97 km north of the westernmost part of ENP. This expanded increment over the ENP from a generally northwesterly direction. The 1992 natural gas repowering of the FP&L Lauderdale Plant in Dania expanded increment at ENP from a generally northeasterly direction.

Similarly, the FP&L Port Everglades Plant in Broward County and the FP&L Rivera Plant in Palm Beach County use cleaner fuel oil than required and use substantial amounts of natural gas. This probably adds further to any actual to actual analysis of increment expansion.

In conclusion all indications are that SO₂ emissions have been reduced locally and regionally. A modeling effort would likely show improvements rather than degradation related to SO₂ at the ENP since the late 1970's. The Department believes this analysis is sufficient to support issuance of this permit without further detailed analysis.

13. In a letter received July 2, 2004 from FP&L (Barbara Linkiewicz), FPL requested revision of Section III, specific condition 8, b. as follows:

Authorized fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. ~~Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months.~~ The four gas turbines shall fire no more than a cumulative total of 28,028,168 gallons of fuel oil during any calendar year.

Following discussions with the Department and considering EPA's concern regarding the fuel versus hourly limitation for duct burning, FP&L withdrew the request. In this case, the theoretical, but unlikely use of fuel oil for 2000 hours in a single unit and 0 hours in the others might have changed the final BACT.

By electronic communication dated August 15, 2004, FP&L replaced their request in Item 13 with the following:

Authorized Fuels: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months calendar year.

The revised request has no practical effect on emissions or the BACT basis for SO₂. The Department will revise the Authorized Fuels condition per the revised request.

14. In the July 2, 2004 letter, FP&L requests the following change to Section III, Specific Condition 9.f.:

Each SCR system shall be designed and operated for ammonia slip limit of less no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs.

The Department will revise this emission standard adding the proposed language.

15. In the July 2, 2004 letter, FPL states:

"In Section III, pages 14-15, we request the clarifications below. Recognizing that quarterly reports contain all NSPS and State requirements, this clarification combines the quarterly and semi annual reports. The proposed language below also makes Condition 27 consistent with Condition 25a regarding the monitoring period".

Condition 27. ~~Semiannual NSPS Excess Emissions Report.~~ Quarterly Excess Emission Report: ~~In accordance with 40 CFR 60.7 (d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards w~~ Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the permit standards following the NSPS format provided in Appendix XS of this permit. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any ~~daily~~ monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown. ~~An example of the report is provided on Appendix XS.~~ Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

~~Condition 28. Quarterly Permit Excess Emissions Report Semiannual NSPS Excess Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the permit standards. Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62.4.130, 62.204.800, 62.210.700(6), F.A.C.; and 40 CFR 60.7]. The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.~~

The Department will adopt these changes with some additional clarification. The reports will include excess emissions related to the BACT determination and any other SIP-based emission limits in addition to the NSPS excess emission reporting requirements.

The other change reflects the recent revision of 40 CFR 60 Subpart GG that defines excess emissions based on CEMS in lieu of water-to-fuel ratio.

16. On August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. The relevant provision of the rule that stays the effectiveness for units such as proposed at Turkey Point follows:

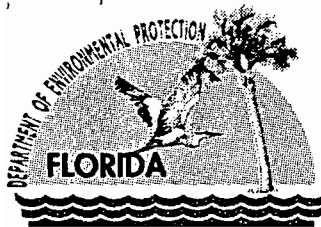
40 CFR 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

The Department has updated relevant parts of the permit and summarized in Appendix YYYYY of the permit, the applicable requirements of Subparts A and YYYYY in 40 CFR 63.

CONCLUSION

The final action of the Department is to issue the permit with the changes noted above.



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

PERMITTEE:

Florida Power & Light
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:

Scott Stone, Plant General Manager

FP&L Turkey Point Fossil Plant
DEP File No. 0250003-006-AC
Permit No. PSD-FL-338
SIC No. 4911
Expires: December 31, 2008

PROJECT AND LOCATION

This permit authorizes the construction of Unit 5 at the existing FP&L Turkey Point Fossil Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will include four 170 MW gas turbine-electrical generator sets, four heat recovery steam generators, a single 470 MW steam turbine-electrical generator, and a mechanical draft cooling tower. The existing FP&L Turkey Point Fossil Plant is located east of Homestead and Florida City and next to Biscayne Bay in Miami-Dade County, Florida. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

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- Section I. General Information
- Section II. Administrative Requirements
- Section III. Emissions Units Specific Conditions
- Section IV. Appendices

Michael G. Cooke for 2/8/05

Michael G. Cooke, Director (Date)
Division of Air Resources Management

SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The existing Turkey Point Fossil Plant currently consists of two fossil fuel-fired steam electrical generating units and five “Black Start” diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The proposed “4 on 1” combined cycle Unit 5, which will consist of four gas turbines (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. New combined cycle Unit 5 will have a total generating capacity of approximately 1150 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
005	Unit 5A gas turbine (170 MW) with supplementary-fired heat recovery steam generator
006	Unit 5B gas turbine (170 MW) with supplementary-fired heat recovery steam generator
007	Unit 5C gas turbine (170 MW) with supplementary-fired heat recovery steam generator
008	Unit 5D gas turbine (170 MW) with supplementary-fired heat recovery steam generator
009	One distillate fuel oil storage tank for Unit 5 gas turbines
010	Mechanical draft cooling tower for Unit 5

Note: FPL Turkey Point Fossil Plant Unit 5 consists of four gas combustion turbine-electrical generator sets (Units 5A-5D), four supplementary gas-fired heat recovery steam generators (HRSGs), and a single steam turbine-electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is subject to 40 CFR 63, Subpart YYYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYYY of this permit).

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as “attainment,” “maintenance,” or “unclassifiable” for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a “fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input”, which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

SECTION I. GENERAL INFORMATION

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Miami-Dade County Department of Environmental Resources Management (DERM), Air Quality Management, 33 Southwest 2nd Avenue, Suite 900, Miami, Florida 33130-1540.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix CF. Citation Format and Definitions

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

Appendix YYYY. NESHAP Requirements for Gas Turbines from 40 CFR 63, Subpart YYYY

Appendix XS. Semiannual NSPS Excess Emissions Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on November 14, 2003;
- Department PSD Application Sufficiency comments dated January 2, 2004;
- Environmental Protection Agency Region 4 letter dated January 15, 2004;
- Department of Interior/NPS letter dated February 27, 2004;
- Sufficiency Responses received March 1, 2004;
- Letter dated April 19, 2004 from Golder in response to NPS letter dated February 27, 2004;
- Draft permit package issued on May 28, 2004;
- Letter dated July 1, 2004 from FP&L regarding draft permit;
- Letter dated July 2, 2004 from National Park Service regarding draft permit;
- Letter dated July 8, 2004 from EPA regarding draft permit;
- Final Certification by the Power Plant Siting Board on February 1, 2005; and
- Final Determination on PSD Permit distributed concurrently with Final PSD Permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]
4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]
6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]
7. Title V Permit Revision: The permittee shall submit an application for a revised Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

This section of the permit addresses the following emissions units.

Emissions Units 005, 006, 007, 008

Description: Emissions units 005, 006, 007, and 008 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate supplementary-fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a generating capacity of 470 MW. The total generating capacity of the "4 on 1" combined cycle unit is approximately 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, PM/PM₁₀, SAM, SO₂ and VOC. Dry Low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system further reduces NO_x emissions.

Stack Parameters: Each HRSG has a stack at least 130 feet tall with a nominal diameter of 19 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics:

<u>Fuel</u>	<u>Heat Input Rate (LHV)</u>	<u>Compressor Inlet Temp.</u>	<u>Exhaust Temp., °F</u>	<u>Flow Rate ACFM</u>
Gas	1,608 MMBtu/hour	59° F	202° F	1,023,872
Oil	1,830 MMBtu/hour	59° F	295° F	1,224,407

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. **BACT Determinations:** Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfuric acid mist (SAM), sulfur dioxide (SO₂) and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
2. **NSPS Requirements:** The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]
- 2.a. **NESHAP Requirements:** The combustion turbines are subject to 40 CFR 63, Subpart YYYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYYY until EPA takes final action to require compliance and publishes a document in the Federal Register.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the SpeedtronicTM automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to 290 °F before combustion to increase overall unit efficiency. This will be accomplished by feedwater heat exchangers. [Application; Design]
4. Gas Turbine NO_x Controls
 - a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_x emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_x values to meet the NO_x limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH₃) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_x and NH₃ emissions.
 - d. *Ammonia Storage*: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Design; Rule 62-212.400(BACT), F.A.C.]
5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (5A-5D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_x/MMBtu. {Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.} [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,608 MMBtu per hour when firing natural gas and 1,830 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]
8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
 - a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
 - b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any calendar year.
 - c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
 - d. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."
 - e. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.
 - f. *High Power Modes (Peaking and Power Augmentation)*: When firing natural gas and only while practicing duct firing, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. When firing natural gas and only while practicing duct firing, steam may be injected into each gas turbine expansion section to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation," the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total hours of power augmentation plus the total hours of peaking shall not exceed 400 hours per gas turbine during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
	CT & DB & PA	NA	NA	14.0, 24-hr	
	Oil/Gas	All Modes	NA	NA	6, 12-month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- a. Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
- b. Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

- c. The sulfur fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard and Section 24.41.1 of the Miami-Dade County Code shall be demonstrated by conducting tests in accordance with EPA Method 9.
- d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section. Compliance with the SO₂ BACT also insures compliance with Section 24.41.3 of the Miami-Dade County Code.
- e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- f. Each SCR system shall be designed and operated for ammonia slip limit of no more than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "PK" means peaking, "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

[Rule 62-212.400(BACT), F.A.C.]

- 10. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. This is not considered a separate mode of operation with respect to emission limits. When operating in this manner, each unit shall comply with the respective standards given in Condition 9 for each mode of operation indicated therein. [Application]
- 11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. *{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da}* [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

- 12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]
14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]
15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A “documented malfunction” means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.
 - a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold “startup of the steam turbine system” is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*
 - b. For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.
 - c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. “Cold startup of a gas turbine/HRSG system” is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.
 - d. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]
16. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer’s specifications. A “major tuning session” would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

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A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

EMISSIONS PERFORMANCE TESTING

17. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "<http://www.epa.gov/ttn/emc/ctm.html>". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

18. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_x, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Stack test data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_x mass rate emissions standards. CO and NO_x emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]
19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_x limits for each method of operation given in Condition 9 above. [Rule 62-212.400 (BACT), F.A.C.]
20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

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{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

21. **CEM Systems:** The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_x from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_x standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
- CO Monitors.** The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - NO_x Monitors.** Each NO_x monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NO_x monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
 - Diluent Monitors.** The oxygen (O₂) or carbon dioxide (CO₂) content of the flue gas shall be monitored at the location where CO and NO_x are monitored to correct the measured emissions rates to 15% oxygen. If a CO₂ monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
 - 1-Hour Block Averages.** Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0%

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_x as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

- e. *24-hour Block Averages:* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_x emissions depending on the use of alternate methods of operation}.* [Rule 62-212.400(BACT), F.A.C.]
- f. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- g. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

- 22. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_x emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_x monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

RECORDS AND REPORTS

23. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
24. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
25. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.
- Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.
 - Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

26. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

27. Quarterly Excess Emission Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_x emissions in excess of the permit standards (BACT, SIP, NSPS) following the NSPS format provided in Appendix XS of this permit.

For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NO_x concentration exceeds the NSPS NO_x emission standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_x or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO₂ emissions in excess of the NSPS standards except during startup or shutdown.

Such information shall be summarized for all exceedances including startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7, and 60.334(j)(1)]

28. Semiannual NSPS Excess Emissions Report: The submittal of the Quarterly Excess Emission Reports shall constitute compliance with the requirements of 40 CFR 60.7(d) for the submittal of Semiannual Excess Emissions Report.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
009	One distillate fuel oil storage tank for Unit 5 gas turbines (approximately 4.2 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.; and Section 24.41.6, Miami-Dade County Code.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 4.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 5 gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

C. COOLING TOWER (EU 010)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
010	22-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 22-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM₁₀ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM₁₀ per year. Actual emissions are expected be lower than these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

SECTION IV. APPENDICES

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SECTION IV. APPENDIX A
NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

- § 60.1 Applicability.
- § 60.2 Definitions.
- § 60.3 Units and abbreviations.
- § 60.4 Address.
- § 60.5 Determination of construction or modification.
- § 60.6 Review of plans.
- § 60.7 Notification and Record Keeping.
- § 60.8 Performance Tests.
- § 60.9 Availability of information.
- § 60.10 State Authority.
- § 60.11 Compliance with Standards and Maintenance Requirements.
- § 60.12 Circumvention.
- § 60.13 Monitoring Requirements.
- § 60.14 Modification.
- § 60.15 Reconstruction.
- § 60.16 Priority List.
- § 60.17 Incorporations by Reference.
- § 60.18 General Control Device Requirements.
- § 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

SECTION IV. APPENDIX BD

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	- Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O ₂	lb/hr ^g	ppmvd @ 15% O ₂
CO ^a	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
	Oil/Gas	All Modes	NA	NA	6, 12 month
NO _x ^b	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM ₁₀ ^c	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂ ^d	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC ^e	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia ^f	Oil/Gas	CT, All Modes	5	NA	NA

- Continuous compliance with the continuous 24-hour and 12 month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.
- Continuous compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂.
- The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
- The fuel sulfur specifications effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
- Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.
- The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

SECTION IV. APPENDIX BD
FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

A A Linero 2/1/05

Recommended By:

Approved By:

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

2/8/05

Date

Michael G. Cooke

Michael G. Cooke, Director
Division of Air Resources Management

2/8/05

Date

SECTION IV. APPENDIX CF
CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001" identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

- (119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.
- (179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
- (258) Shutdown - The cessation of the operation of an emissions unit for any purpose.
- (275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

SECTION IV. APPENDIX Da

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 5 gas turbine/HRSG systems, which are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

“Duct burner” means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

“Electric utility combined cycle gas turbine” means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Electric utility steam generating unit” means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

“Fossil fuel” means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

“Gross output” means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

“Potential electrical output capacity” is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

“Steam generating unit” means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM₁₀ emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil ($\leq 0.05\%$ sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO₂ emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO₂) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NO_x) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})] / (O_{sg} \times h) \quad (\text{Equation 1})$$

Where:

- E = Emission rate of NO_x from the duct burner, ng/J (lb/Mwh) gross output
- C_{sg} = Average hourly concentration of NO_x exiting the steam generating unit, ng/dscm (lb/dscf)
- C_{te} = Average hourly concentration of NO_x in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
- Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
- Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
- O_{sg} = Average hourly gross energy output from steam generating unit, J (Mwh)
- h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_x concentrations (C_{sg} and C_{te}). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Q_{sg} and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1- hour runs) for the initial performance tests. Thereafter, compliance with the NO_x limits established in the PSD permit shall demonstrate compliance with NO_x limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

SECTION IV. APPENDIX Da
NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

Determine compliance with the applicable NO_x emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_x standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_x emission rate when demonstrating compliance with the NO_x standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
 - a. Have access to and copy and records that must be kept under the conditions of the permit;
 - b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
 - c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
 - a. A description of and cause of non-compliance; and
 - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
 - a. Determination of Best Available Control Technology (X);
 - b. Determination of Prevention of Significant Deterioration (X);
 - c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
 - d. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
 - a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - c. Records of monitoring information shall include:
 - 1) The date, exact place, and time of sampling or measurements;
 - 2) The person responsible for performing the sampling or measurements;
 - 3) The dates analyses were performed;
 - 4) The person responsible for performing the analyses;
 - 5) The analytical techniques or methods used; and
 - 6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SECTION IV. APPENDIX GG
NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The Unit 5 gas turbines are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.330 Applicability and Designation of Affected Facility.

Each Unit 5 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

- (a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.
- (b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.
- (d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.
- (g) ISO standard day conditions mean 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.
- (h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.
- (i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.
- (j) Base load means the load level at which a gas turbine is normally operated.
- (q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_x) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

$$\text{STD} = 0.0075 \frac{(14.4)}{Y} + F$$

Where:

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NO_x contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NO_x emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NO_x standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil ($\leq 0.05\%$ sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_x standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NO_x emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_x) for each run using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) (\text{Pr}/\text{Po})^{0.5} e^{19(\text{Ho}-0.00633)} (288^\circ\text{K}/\text{Ta})^{1.53}$$

Where:

- NO_x = Emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, volume percent
- NO_{x0} = Observed NO_x concentration, ppm by volume
- Pr = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
- Po = Observed combustor inlet absolute pressure at test, mm Hg
- Ho = Observed humidity of ambient air, g H_2O /g air
- e = Transcendental constant, 2.718
- Ta = Ambient temperature, $^\circ\text{K}$

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_x monitor shall be used to demonstrate compliance with the specified NO_x limits. The permittee is allowed to make the initial compliance demonstration for NO_x emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_x monitor. The permittee is not required to have the NO_x monitor continuously correct NO_x emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]
12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
 - a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
 - b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
 - c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.[Rule 62-297.310(4), F.A.C.]
14. Determination of Process Variables
 - a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
 - b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.[Rule 62-297.310(5), F.A.C.]
15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.
16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]
17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]
18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

- 1) The type, location, and designation of the emissions unit tested.
- 2) The facility at which the emissions unit is located.
- 3) The owner or operator of the emissions unit.
- 4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
- 5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
- 6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
- 7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
- 8) The date, starting time and duration of each sampling run.
- 9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
- 10) The number of points sampled and configuration and location of the sampling plane.
- 11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
- 12) The type, manufacturer and configuration of the sampling equipment used.
- 13) Data related to the required calibration of the test equipment.
- 14) Data on the identification, processing and weights of all filters used.
- 15) Data on the types and amounts of any chemical solutions used.
- 16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
- 17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
- 18) All measured and calculated data required to be determined by each applicable test procedure for each run.
- 19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
- 20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
- 21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION IV. APPENDIX XS
SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant (*Circle One*): SO₂ NO_x TRS H₂S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ¹: _____

Emission data summary ¹	CMS performance summary ¹
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. Total duration of excess emissions x (100) / [Total source operating time] % ²	1. CMS downtime in reporting period due to: a. Monitor equipment malfunctions b. Non-Monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CMS Downtime 3. [Total CMS Downtime] x (100) / [Total source operating time] % ²

¹ For opacity, record all times in minutes. For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ Date: _____

Title: _____

SECTION IV. APPENDIX YYYY
NESHAP REQUIREMENTS FOR GAS TURBINES

Applicability of NESHAP Subpart YYYY

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O₂). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

According to General Electric, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposed to meet the limit proposed in YYYY of 91 ppbvd based on the performance of the GE 7FA unit. The very low CO and VOC emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_x combustion technology employed by these units ensure that formaldehyde emissions will be at the lowest end of the spectrum.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the Turkey Point Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

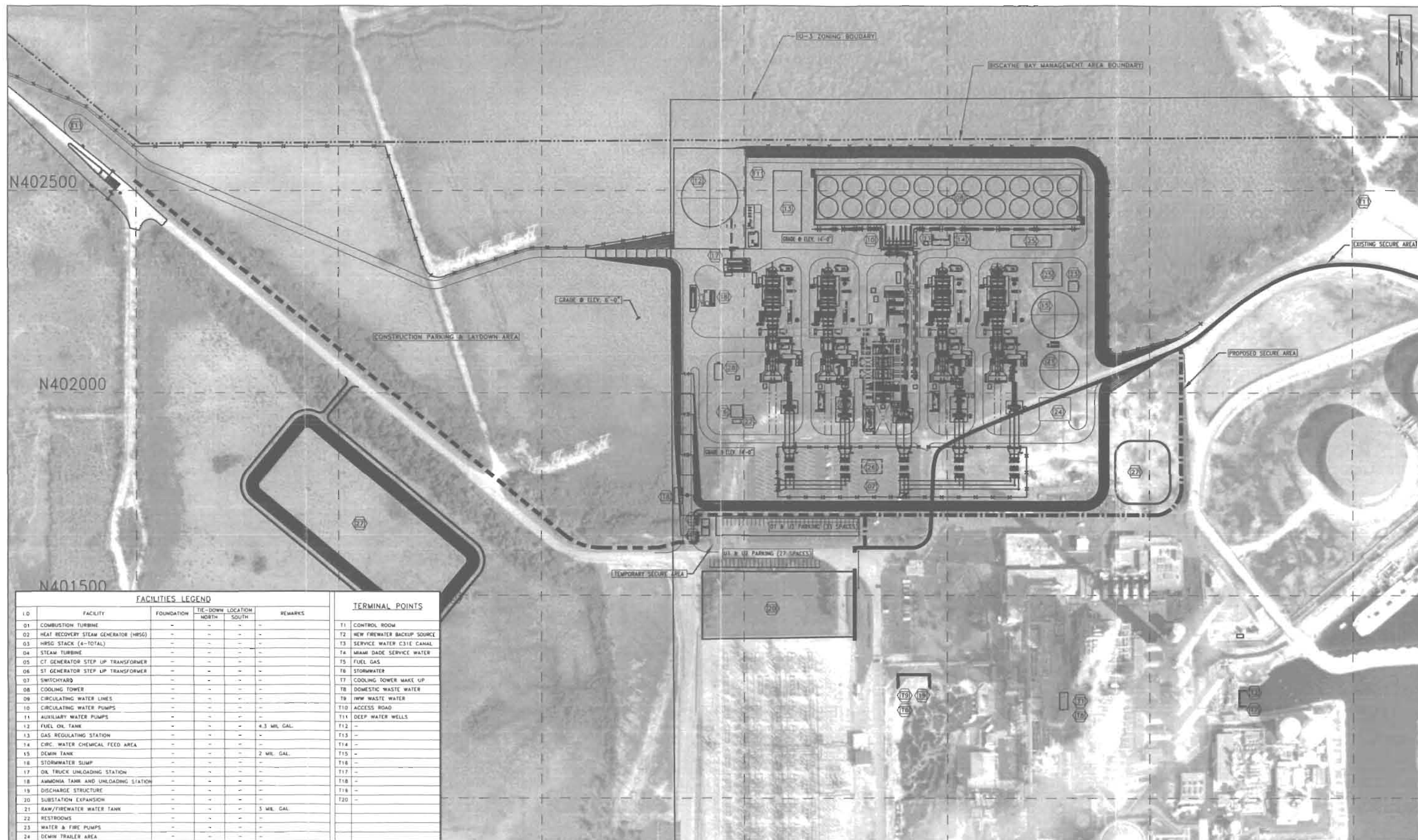
Requirements

The applicable requirements in Subpart YYYY at the time this permit was issued (February 2005) were:

§ 63.6145 What notifications must I submit and when?

- (a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.
- (b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.
- (c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.
- (d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).
- (e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).
- (f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]



FACILITIES LEGEND				
I.D.	FACILITY	FOUNDATION	TIE-DOWN LOCATION NORTH SOUTH	REMARKS
01	COMBUSTION TURBINE	-	-	-
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	-	-	-
03	HRSG STACK (4-TOTAL)	-	-	-
04	STEAM TURBINE	-	-	-
05	CT GENERATOR STEP UP TRANSFORMER	-	-	-
06	ST GENERATOR STEP UP TRANSFORMER	-	-	-
07	SWITCHYARD	-	-	-
08	COOLING TOWER	-	-	-
09	CIRCULATING WATER LINES	-	-	-
10	CIRCULATING WATER PUMPS	-	-	-
11	AUXILIARY WATER PUMPS	-	-	-
12	FUEL OIL TANK	-	-	4.3 MIL. GAL.
13	GAS REGULATING STATION	-	-	-
14	CIRC. WATER CHEMICAL FEED AREA	-	-	-
15	DEMIN. TANK	-	-	2 MIL. GAL.
16	STORMWATER SUMP	-	-	-
17	OIL TRUCK UNLOADING STATION	-	-	-
18	AMMONIA TANK AND UNLOADING STATION	-	-	-
19	DISCHARGE STRUCTURE	-	-	-
20	SUBSTATION EXPANSION	-	-	-
21	RAW/TREATED WATER TANK	-	-	5 MIL. GAL.
22	RESTROOMS	-	-	-
23	WATER & FIRE PUMPS	-	-	-
24	DEMIN. TRAILER AREA	-	-	-
25	WATER TREATMENT AREA	-	-	-
26	RELAY VAULT	-	-	-
27	STORMWATER POND	-	-	POTENTIAL
28	H2 BULK STORAGE	-	-	-

TERMINAL POINTS

T1	CONTROL ROOM
T2	NEW FIREWATER BACKUP SOURCE
T3	SERVICE WATER CS1E CANAL
T4	MIAMI DADE SERVICE WATER
T5	FUEL GAS
T6	STORMWATER
T7	COOLING TOWER MAKE UP
T8	DOMESTIC WASTE WATER
T9	WWP WASTE WATER
T10	ACCESS ROAD
T11	DEEP WATER WELLS
T12	-
T13	-
T14	-
T15	-
T16	-
T17	-
T18	-
T19	-
T20	-

ASPHALT PAVING

AGGREGATE SURFACING

CONCRETE SURFACING

EXISTING FENCING

NEW FENCING

0
REV

10/31/03
DATE

ISSUED FOR SCA USE

REVISION DESCRIPTION

OMG
BY CH COR APR ORG



SYSTEM
N/A
SCALE
1"=100'
DRAWING SIZE
D(24"x36")
DRAWING NUMBER
0337600/4.2/4.2.1/Appendix 10.1.5/Figure 2-2.dwg

DISCIPLINE
CS
CWD FILE NAME
Figure 2-2.dwg
PL ARCHIVE NAME
N/A

FILE
TITLE
TURKEY POINT
FIGURE 2-2
EXPANSION PROJECT
AERIAL DERIVED PLOT PLAN

SHEET
1 OF 1

REV
0

BNR CODE

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR; WI		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NO _x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.046 lb/mmbtu	SCR/WI		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu)	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
Tenaska Alabama IV Partners	AL	Oct-01	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOX - \$6,145/ton NO _x ; CatOx-\$1,506/ton CO
Duke Energy Autauga, LLC	AL	Oct-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOX - \$18760/ton NOX; CatOx-\$5,006/ton CO
Duke Energy Dale, LLC	AL	Dec-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmbtu)	SCR		SCONOX - \$18,403/ton NOX; CatOx-\$2,634/ton CO+VOC
Barton Shoals Energy, LLC	AL	Jul-02	1,200	4	4	GE 7FA (170 MW)	NG	CC	8,760	2.5 ppm (0.0092 lb/mmbtu)	SCR		EPA did not received application until 5/24/02
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	Netting out of PSD for NO _x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD review for NO _x

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	SCONox - \$16,712/ton NO _x ; CatOx - \$2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		SCONox - no cost eval.; CatOx - \$4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		Repowering project: netting out of NO _x , CO, PM ₁₀ and SO ₂ review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		base/duct burner/power aug./60-70% load; SCONox - \$9,982/ton NO _x ; CatOx - \$1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	Mar-02	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		
Broward Energy Center	FL	May-02	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	Aug-02	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	Jan-02	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Repowering Project: Netting out of PSD for NO _x , SO ₂ , VOC, lead and SAM (subject for PM ₁₀ and CO)
CPV Cana Power Generation Facility	FL	01/17/2002	245	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR		PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FPL Martin	FL	04/16/2003	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	2.5 ppm NG; 10 ppm FO/9-15 ppm NG; 42 ppm FO	SCR/DLN; WI		PA = Power Augmentation
FPL Manatee	FL	04/15/2003	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	2.5 ppm CC/9-15 ppm SC	SCR/DLN		PA = Power Augmentation
FPC - Hines Energy Complex	FL	draft permit	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG/ 10 ppm FO	SCR		SCONox - \$8,597/ton NO _x ;
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Buffalo Creek, LLC	GA	Oct-00	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		SCONox - \$19,948/ton NO _x ; CatOx - \$2,469/ton CO
Augusta Energy LLC	GA	Oct-00	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONox - \$17,490/ton NO _x ; CatOx - \$4,133/ton CO

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
GenPower Rincon	GA	Dec-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Effingham Power Co.	GA	Dec-00	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	Feb-01	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	3.5/9 ppm	SCR/DLN;		
CPV Terrapin, LLC	GA	Jun-01	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 5.4 ppm (NG w/DB); 8.0 ppm FO	SCR		
Savannah Electric and Power - Plant McIntosh	GA	04/17/2003	1,260	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.5 ppm NG; 6 ppm FO	SCR		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
Live Oak Co., LLC	GA	applic. under review	600	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Pecan Grove Generating	GA	applic. under review	550	2	2	SW 501FD (175 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm NG; 12. ppm FO	SCR		
Big River Power, LLC	GA	applic. under review	855	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	3.0 ppm NG; 8.0 ppm FO	SCR/DLN; WI		SCR - \$5,075/ton NO _x ; CatOx - \$4,712/ton CO
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
Duke Energy Trimble	KY	applic. under review	1,240	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm	SCR		
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Cogentrix Energy, Southaven Power Project	MS	Apr-00	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/DB)	DLN/SCR		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		revised application to add SCR
GenPower - McAdams LLC	MS	Aug-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
Lone Oak Energy Center	MS	Nov-01	800	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
Lee Power Partners	MS	Mar-01	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
LSP-Pike Energy LLC	MS	Nov-00	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
Magnolia Energy	MS	May-01	900	3	3	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	3.5 ppm	DLN, SCR		
Reliant Energy - Choctaw Co., LLC	MS	Jun-01	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	SCONOX - \$48,663/ton NO _x ; CatOx - \$3,550/ton CO
Crossroads Energy Center	MS	Jun-02	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOX - \$23,400/ton NO _x ; CatOx - \$11,039/ton CO
Choctaw Gas Generation, LLC	MS	Dec-01	700	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	
Granite Power Partners II (Batesville)	MS	Nov-01	300	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR		
Panada Black Prairie LP	MS	applic. under review	1,040	4	4	F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR		GE7FA or SW501F
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	Nov-99	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
GenPower Earleys, LLC	NC	Jan-02	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOX - \$21,942/ton NO _x ; CatOx - \$3,246ton CO

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Mirant Gastonia	NC	05/28/2002	1,200	4	4	"F" Class (175 MW)	NG	CC	8,760	2.5/3.5 ppm	SCR		CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
Carolina Plant	NC	applic. under review	1,300	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	2.5/3.5 ppm; 13/18 ppm	SCR		CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
Mountain Creek - Granville Energy Center	NC	applic. under review	911	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONox - \$22,600/ton NOx; CatOx - \$3,560ton CO
Dominion Person, Inc.	NC	applic. under review	1,100	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm; 15 ppm FO	SCR		
Forsyth Energy Project	NC	applic. under review	812	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	2.5/3.5 ppm NG; 13/18 ppm FO	SCR		CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		Netted out of NO _x , SO ₂ and PM ₁₀ PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		SCONox - no analysis; CatOx - \$1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	3.5 ppm	DLN/SCR		
Greenville Power Project	SC	applic. under review	810	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 20 ppm FO	SCR		SCONox - \$18,300/ton NOx; CatOx - \$5,800/ton CO; DB < 5,120 hr/yr
Jasper County Generating Facility	SC	05/28/2002	1,260	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	2.5 ppm NG; 7.5 ppm FO	SCR		SCONox - \$19,870/ton NOx; CatOx - \$3,320/ton CO
Cherokee Falls Combined-Cycle Facility	SC	applic. under review	1,260	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONox - \$22,434/ton NOx; CatOx - \$2,500/ton CO
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR		
Palmetto Energy Center	SC	applic. under review	970	3	3	GE 7FB (180 MW)	NG	CC	8,760	3.5 ppm	SCR		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		
Memphis Generation LLC	TN	Apr-01	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	Feb-02	900	3	3	SW, GE 7FA or GE	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TVA - Franklin	TN	draft permit	610	2	2	GE 7FA (195 MW)		CC	8,760	3.5 ppm	SCR		
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	3.5/9 ppm NG; 12/42 ppm FO	SCR/DLN; SCR/WI		

Abbreviations:

GE = General Electric
SW = Seimens Westinghouse

NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner

SC = Simple Cycle
CC = Combined Cycle

DLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic Reduction

CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NO _x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.089 lb/mmBtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmBtu (base/PA/FO) - Mit	GCP		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
Tenaska Alabama IV Partners	AL	Oct-01	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONOX - \$6,145/ton NO _x ; CatOx- \$1,506/ton CO
Duke Energy Autauga, LLC	AL	Oct-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONOX - \$18760/ton NO _x ; CatOx- \$5,006/ton CO
Duke Energy Dale, LLC	AL	Dec-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	0.033 lb/mmBtu	GCP		SCONOX - \$18,403/ton NO _x ; CatOx- \$2,634/ton CO+VOC
Barton Shoals Energy, LLC	AL	Jul-02	1,200	4	4	GE 7FA (170 MW)	NG	CC	8,760	10 ppm (0.022 lb/mmBtu); 0.041 lb/mmBtu w/DB	GCP		EPA did not received application until 5/24/02
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NO _x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NO _x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOX - \$16,712/ton NO _x ; CatOx - \$2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONOX - no cost eval.; CatOx - \$4,350/ton CO

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NO _x , CO, PM ₁₀ and SO ₂ review (subject to VOC review)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - \$9,982/ton NO _x ; CatOx - \$1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	Mar-02	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	12.21/14.17 ppm	GCP		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
Broward Energy Center	FL	May-02	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (7.8 ppm)	GCP	24-hr (3-hr test)	Repowering Project: Netting out of PSD for NO _x , SO ₂ , VOC, lead and SAM (subject for PM ₁₀ and CO)
CPV Cana Power Generation Facility	FL	01/17/2002	245	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17/19/26 ppm FO	GCP	24-hr	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FPL Martin	FL	04/16/2003	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	10 ppm NG/8 ppm NG (12 ppm w/PA); 15 ppm FO	GCP	24-hr	PA = Power Augmentation
FPL Manatee	FL	04/15/2003	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	10 ppm NG/8 ppm NG (12 ppm w/PA)	GCP	24-hr	PA = Power Augmentation
FPC - Hines Energy Complex	FL	draft permit	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	10 ppm NG/20 ppm FO	GCP	24-hr	SCONOx - \$8,597/ton NO _x ;
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	21.8 ppm	GCP		
Duke Energy Buffalo Creek, LLC	GA	Oct-00	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	21.9 ppm	GCP		SCONOx - \$19,948/ton NO _x ; CatOx - \$2,469/ton CO
Augusta Energy LLC	GA	Sep-01	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	17.4 ppm NG; 20 ppm FO	GCP		SCONOx - \$17,490/ton NO _x ; CatOx - \$4,133/ton CO
GenPower Rincon	GA	Dec-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm/14 (w/DB) ppm	GCP		
Effingham Power Co.	GA	Dec-00	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Peace Valley Generation Co., LLC	GA	draft permit	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	10.6 ppm (25 ppm w/DB)	GCP		
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 13.6 ppm (NG w/DB); 24 ppm FO	GCP	24-hr rolling	
Savannah Electric and Power - Plant McIntosh	GA	04/17/2003	1,260	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.0 ppm	CatOx		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
Live Oak Co., LLC	GA	applic. under review	600	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP		
Pecan Grove Generating	GA	applic. under review	550	2	2	SW 501FD (175 MW)	NG; FO	CC	8,760; 500 FO	15;22.9;25;50 ppm (NG; NG w/DB;NG @70%; FO)	GCP		
Big River Power, LLC	GA	applic. under review	855	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	19.2 ppm (w/DB)/9.0 ppm (w/o DB) NG; 20.0 ppm FO	GCP		SCR - \$5,075/ton NO _x ; CatOx - \$4,712/ton CO
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	GCP	3-hr	
Duke Energy Trimble	KY	applic. under review	1,240	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	9/13.9/20 ppm	GCP		
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Cogentrix Energy, Southaven Power Project	MS	Apr-00	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 18 ppm w/ DB	GCP		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		revised application to add SCR
GenPower - McAdams LLC	MS	Aug-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
Lone Oak Energy Center	MS	Nov-01	800	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
Lee Power Partners	MS	Mar-01	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
LSP-Pike Energy LLC	MS	Nov-00	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP		
Magnolia Energy	MS	May-01	900	3	3	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	20 ppm	GCP		
Reliant Energy - Choctaw Co., LLC	MS	Jun-01	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.36 ppm	GCP		SCONO _x - \$48,663/ton NO _x ; CatOx - \$3,550/ton CO
Crossroads Energy Center	MS	Jun-02	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		SCONO _x - \$23,400/ton NO _x ; CatOx - \$11,039/ton CO
Choctaw Gas Generation, LLC	MS	Dec-01	700	2	2	SW 501G (250 MW)	NG	CC	8,760	23 ppm	GCP		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	20.4 ppm	GCP	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	25 ppm	GCP		
Panada Black Prairie LP	MS	applic. under review	1,040	4	4	F" Class (175 MW)	NG	CC	8,760	7.6 ppm or 80 ppm	GCP		GE7FA or SW501F
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 41 ppm FO	GCP		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (14 ppm w/DB)	GCP		SCONO _x - \$21,942/ton NO _x ; CatOx - \$3,246/ton CO
Mirant Gastonia	NC	05/28/2002	1,200	4	4	"F" Class (175 MW)	NG	CC	8,760	15 or 30 ppm	GCP	24-hr block	CO Limit depends on CT model; NO _x limit depends on operating history and 3.3 ppm trigger level

Table B-7. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2003

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Carolina Plant	NC	applic. under review	1,300	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	47 or 50 ppm	GCP	24-hr block	CO Limit depends on CT model; NO _x limit depends on operating history and 3.3 ppm trigger level
Mountain Creek - Granville Energy Center	NC	applic. under review	911	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (24.3 ppm w/DB)	GCP		SCONox - \$22,600/ton NO _x ; CatOx - \$3,560/ton CO
Dominion Person, Inc.	NC	applic. under review	1,100	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	9 ppm NG (20 ppm w/DB) 20 ppm FO	GCP		
Forsyth Energy Project	NC	applic. under review	812	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	25.9 ppm NG (w/DB); 25.1 ppm FO (w/DB)	GCP	24-hr block	CO Limit depends on CT model; NO _x limit depends on operating history and 3.3/17 ppm trigger levels
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	12 ppm NG; 20 ppm FO	GCP		Netted out of NO _x , SO ₂ and PM ₁₀ PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	17.4 ppm NG; 37 ppm FO	GCP		SCONox - no analysis; CatOx - \$1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	11.7 ppm	GCP		
Greenville Power Project	SC	applic. under review	810	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	12.3 ppm NG; 16.5 ppm FO	GCP		SCONox - \$18,300/ton NO _x ; CatOx - \$5,800/ton CO; DB < 5,120 hr/yr
Jasper County Generating Facility	SC	05/28/2002	1,260	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)	GCP		SCONox - \$19,870/ton NO _x ; CatOx - \$3,320/ton CO
Cherokee Falls Combined-Cycle Facility	SC	applic. under review	1,260	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	0.063 lb/mmBtu NG; 0.069 lb/mmBtu FO	GCP		SCONox - \$22,434/ton NO _x ; CatOx - \$2,500/ton CO
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	14 ppm (GE7FA/16 ppm (SW501F)	GCP	24-hr	
Palmetto Energy Center	SC	applic. under review	970	3	3	GE 7FB (180 MW)	NG	CC	8,760	15 ppm (31 ppm w/DB)	GCP		SCONox - \$18,789/ton NO _x ; CatOx - \$2,111/ton CO
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	GCP		
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	25 ppm	GCP		
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	0.035 lb/mmBtu NG; 0.069 lb/mmBtu FO	GCP		

Abbreviations:

GE = General Electric
SW = Seimens WestinghouseNG = Nat. Gas
FO = Fuel Oil
DB = Duct BurnerSC = Simple Cycle
CC = Combined CycleDLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic ReductionCatOx = Catalytic Oxidation
GCP = Good Combustion PracticesSource: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
0250348	Miami-Dade County RRF										
		Units 1&2	DCRRF12	76.2	3.66	405.4	15.86	26.41	12.32	CON	Yes
		Units 3&4	DCRRF34	76.2	3.66	405.4	15.86	26.41	12.32	CON	Yes
0250020	Tarmac										
		Kiln 1 PSD Baseline	TARMK1B	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	Yes
		Kiln 2 PSD Baseline	TARMK2B	61.0	2.44	465.0	12.84	-5.71	-5.71	EXP	Yes
		Kiln 3 PSD Baseline	TARMK3B	61.0	4.57	472.0	10.78	-2.76	-2.76	EXP	Yes
		Kiln 2 PSD	TABMK2	61.0	2.44	422.0	9.10	24.57	24.57	CON	Yes
		Kiln 3 PSD	TARMK3	61.0	4.57	450.0	11.04	51.43	51.43	CON	Yes
0112119	South Broward RRF PSD										
			SBCRRF	59.4	3.96	381.0	18.01	37.91	37.91	CON	Yes
0110037	FPL - Lauderdale										
		CTs 1-4 PSD	LAUDU45	45.7	5.49	438.7	14.60	271.15	271.15	CON	Yes
		4&5 PSD Baseline	FTLAU45B	46.0	4.27	422.0	14.63	-457.00	-457.00	EXP	Yes
0110120	North Broward RRF PSD										
			NBCRRF	58.5	3.96	381.0	18.01	35.40	35.40	CON	Yes
0112545	El Paso Broward										
		Combined Cycle CT CC-1	EPBRCT1	41.1	5.79	359.3	61.13	0.46	0.46	CON	Yes
		Simple Cycle SC-1	EPBRSC1	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-2	EPBRSC2	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-3	EPBRSC3	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
0710019	Lee County RRF PSD										
			LEECORRF	83.8	1.88	388.5	19.81	14.00	14.00	CON	Yes
0990005	Okeelanta ^a										
		Boiler 4 PSD Baseline	OKBLR4B	22.9	2.29	333.0	7.36	-10.95	-10.95	EXP	Yes
		Boiler 5 PSD Baseline	OKBLR5B	22.9	2.29	333.0	12.07	-15.64	-15.64	EXP	Yes
		Boiler 6 PSD Baseline	OKBLR6B	22.9	2.29	334.0	8.74	-15.64	-15.64	EXP	Yes
		Boiler 10 PSD Baseline	OKBLR10B	22.9	2.29	334.0	10.35	-17.15	-17.15	EXP	Yes
		Boiler 11 PSD Baseline	OKBLR11B	22.9	2.29	342.0	9.89	-16.79	-16.79	EXP	Yes

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
0990332	New Hope Power Partnership (Okeelanta)	Boiler 16 PSD	OKBLR16	22.9	1.52	483.0	22.86	1.47	1.47	CON	Yes
		Okeelanta Power Blrs 1,2,3 ^b	OKCOGENF	60.7	3.05	450.9	19.39	57.5	57.5	CON	Yes
0710000	FPL Fort Myers	Unit 1 PSD	FMU1	91.8	2.90	422.0	29.90	-585.50	-585.50	EXP	Yes
		Unit 2 PSD	FMU2	121.2	5.52	408.0	19.20	-1334	-1334.0	EXP	Yes
		HRSBs 1 - 6	FMYHR1_6	38.1	5.79	377.6	14.2	3.86	3.9	CON	Yes
0990016	Atlantic Sugar ^a	Unit 1	ASA1	27.4	1.83	346.0	17.97	16.28	16.28	CON	Yes
		Unit 2	ASA2	27.4	1.83	350.0	23.36	16.28	16.28	CON	Yes
		Unit 3	ASA3	27.4	1.83	350.0	21.56	16.02	16.02	CON	Yes
		Unit 4	ASA4	27.4	1.83	344.0	25.16	16.21	16.21	CON	Yes
		Unit 5 PSD ^b	ASA5	27.4	1.68	339.0	19.24	8.41	8.04	CON	Yes
		Unit 1 PSD Baseline	ASA1B	18.9	1.92	506.0	12.70	-17.24	-17.24	EXP	Yes
		Unit 2 PSD Baseline	ASA2B	18.9	1.92	511.0	10.90	-22.50	-22.50	EXP	Yes
		Unit 3 PSD Baseline	ASA3B	21.9	1.83	522.0	17.50	-16.88	-16.88	EXP	Yes
		Unit 4 PSD Baseline	ASA4B	18.3	1.83	344.0	15.00	-10.76	-10.76	EXP	Yes
0510015	Southern Gardens Citrus - PSD	Peel Dryer	SGARDDRY	38.1	1.73	316.0	7.45	5.29	5.29	CON	Yes
		Boilers 1-3	SGARDBLR	16.8	1.22	478.0	14.22	6.88	6.88	CON	Yes
0990568	Lake Worth Utilities	Unit 5, S-5	LAKWTHU5	22.9	3.05	481.0	27.80	14.37	14.37	CON	Yes
0990026	Sugar Cane Growers ^a	Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	41.20	41.20	CON	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	16.20	16.20	CON	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	38.20	38.20	CON	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	27.90	27.90	CON	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	23.50	23.50	CON	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-24.20	-24.20	EXP	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-4.40	-4.40	EXP	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-24.20	-24.20	EXP	Yes
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-16.20	-16.20	EXP	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-51.00	-51.00	EXP	Yes

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
0990594	El Paso Belle Glade	Combined Cycle CT CC-1	EPBGLCT	41.1	5.79	359.3	61.13	0.46	0.46	CON	Yes
		Simple Cycle SC-1	EPBGSC1	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-2	EPBGSC2	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
		Simple Cycle SC-3	EPBGSC3	41.1	5.79	862.0	146.96	0.46	0.46	CON	Yes
0510003	US Sugar - Clewiston ^c	Unit 8	USSBLR8	60.7	3.96	439.00	15.3	22.1	22.10	CON	Yes
		<u>PSD Baseline (On-crop season only)</u>									
		Unit 1 PSD Baseline	USSBRL1B	23.1	1.86	344.0	30.20	-79.86	-58.21	EXP	Yes
		Unit 2 PSD Baseline	USSBLR2B	23.1	1.86	343.0	35.70	-79.86	-58.21	EXP	Yes
		Unit 3 PSD Baseline	USSBLR3B	27.4	2.29	342.0	14.70	-48.30	-33.20	EXP	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-10.30	-10.30	EXP	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-10.30	-10.30	EXP	Yes
		<u>On-crop season future</u>									
		Unit 1	USSBRL1N	65.0	2.44	347.0	19.20	79.54	74.98	CON	Yes
		Unit 2	USSBLR2N	65.0	2.44	338.7	17.32	79.17	74.12	CON	Yes
		Unit 4	USSBLR4N	45.7	2.51	344.3	24.05	22.49	4.54	CON	Yes
		Unit 7	USSBLR7N	68.6	2.59	405.4	23.60	17.39	15.81	CON	Yes
		<u>Off-crop season future</u>									
		Unit 1	USSBRL1F	65.0	2.44	347.0	17.70	51.64	41.23	CON	Yes
		Unit 2	USSBLR2F	65.0	2.44	338.7	16.19	51.27	37.22	CON	Yes
		Unit 4	USSBLR4F	45.7	2.51	344.3	0.00	0.00	0.00	CON	Yes
		Unit 7	USSBLR7F	68.6	2.59	405.4	23.60	15.86	15.81	CON	Yes
0990234	Palm Beach Co. Resource Recovery 1&2 PSD		PBCRRF	76.2	2.04	505.2	24.90	85.05	85.05	CON	Yes
0990019	Osceola Farms PSD Baseline ^a	Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-5.07	-5.07	EXP	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-16.32	-16.32	EXP	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-7.26	-7.26	EXP	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-13.61	-13.61	EXP	Yes
		Unit 2	OSBLR2	27.4	1.52	341.0	15.82	17.12	5.87	CON	Yes
		Unit 3	OSBLR3	27.4	1.91	342.0	16.86	30.74	6.39	CON	Yes
		Unit 4	OSBLR4	27.4	1.83	340.7	22.80	12.70	11.90	CON	Yes
		Unit 5a	OSBLR5A	27.4	1.52	340.7	18.60	6.33	5.96	CON	Yes

Table D-1. Detailed Summary of Stack, Operating, and Emissions of Facilities with SO₂ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	3-Hour	24-Hour		
0990061	US Sugar-Bryant ^a	Unit 5b	OSBLR5B	27.4	1.52	340.7	18.60	6.33	5.96	CON	Yes
		Unit 6	OSBLR6	27.4	1.88	341.0	18.19	33.39	2.08	CON	Yes
		Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	62.40	62.40	CON	Yes
		Unit 1,2&3 PSD	USBRY123	19.8	1.64	342.0	36.40	160.68	160.68	CON	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-36.50	-36.50	EXP	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-73.00	-73.00	EXP	Yes
990021	Pratt & Whitney (United Technologies)	Heater	PRATARCH	15.2	0.91	810.9	143.73	13.99	13.99	CON	Yes
		Boiler BO-12, -1, -2, -14, -3	PRATBO12	4.6	0.76	533.2	6.92	0.012	0.012	CON	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	75.64	75.64	CON	Yes
0850001	FPL Martin	Aux Blr PSD	MARTAUX	18.3	1.10	535.4	15.24	12.90	12.90	CON	Yes
		Diesel Gens PSD	MARTGEN	7.6	0.30	785.9	39.62	0.51	0.51	CON	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	470.40	470.40	CON	Yes
		Unit 8	MART8OIL	36.6	5.79	420.0	22.40	51.96	51.96	CON	Yes

Note: EXP = PSD expanding source
CON = PSD consuming source

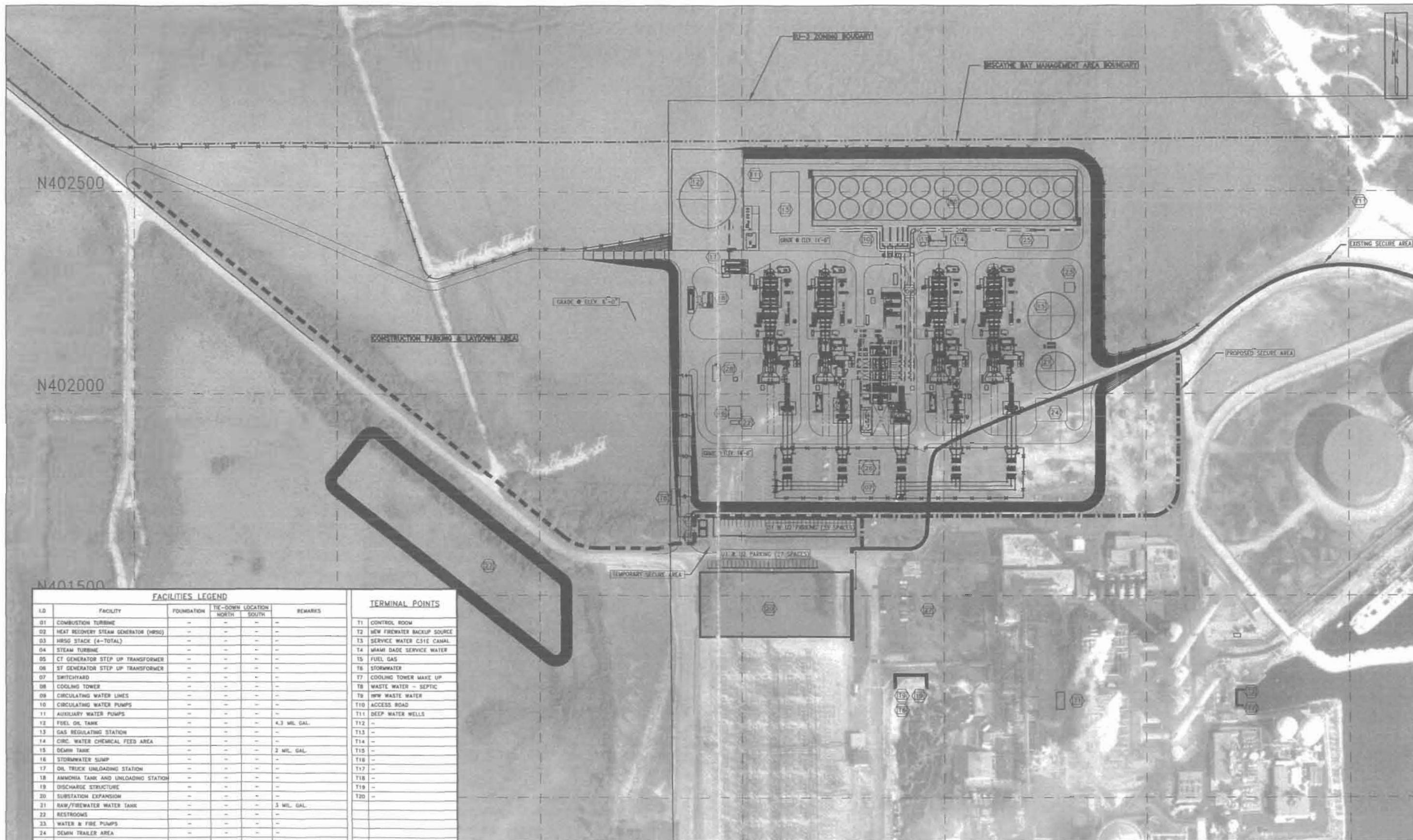
^a Facilities or sources within facilities that operate only during the October 1 through April 30 crop season.

^b Sugar mill sources that operate all year.

^c Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	(lb/hr)	(g/s)		
0250348	Miami-Dade County RRF										
		Units 1&2	DCRRF12	76.2	3.66	405.4	15.86	13.24	1.67	CON	Yes
		Units 3&4	DCRRF34	76.2	3.66	405.4	15.86	13.24	1.67	CON	Yes
0130020	Tarmac										
		Kiln No. 1 Baseline	TARMK1B	61.0	2.44	465.0	12.84	-4.80	-0.60	EXP	Yes
		Kiln No. 2 Baseline	TARMK2B	61.0	2.44	465.0	12.84	-4.80	-0.60	EXP	Yes
		Kiln No. 3 Baseline	TARMK3B	61.0	4.57	472.0	10.78	0.00	0.00	EXP	Yes
		Kiln No. 2	TARMK2	61.0	2.44	422.0	9.10	14.40	1.81	CON	Yes
		Cooler No. 2	TARMC2	26.2	1.82	394.0	8.71	26.40	3.33	CON	Yes
		Kiln No. 3	TARMK3	61.0	4.57	450.0	11.04	42.50	5.36	CON	Yes
		Cooler No. 3	TARMC3	30.5	2.74	394.0	2.88	14.20	1.79	CON	Yes
		Clinker Handling System	TARMCH	48.7	0.30	298.0	32.36	1.76	0.22	CON	Yes
		Finish Mill Nos. 1, 2, 3, and 4	TARMF13	64.0	0.61	372.0	48.54	93.70	11.81	CON	Yes
0112119	South Broward RRF PSD										
			SBCRRF	59.4	3.96	381.0	18.01	24.20	3.05	CON	Yes
0110037	FPL - Lauderdale										
		CTs 1-4 PSD	LAUDU45	45.7	5.49	438.7	14.60	14.70	1.85	CON	Yes
0110120	North Broward RRF PSD	4&5 PSD Baseline	FTLAU45B	46.0	4.27	422.0	14.63	-32.17	-4.05	EXP	Yes
			NBCRRF	58.5	3.96	381.0	18.01	22.83	2.88	CON	Yes
0112545	El Paso Broward										
		Combined Cycle CT CC-1	EPBRCT1	41.1	5.79	359.3	61.13	20.00	2.52	CON	Yes
		Simple Cycle SC-1	EPBRSC1	41.1	5.79	862.0	146.96	20.00	2.52	CON	Yes
		Simple Cycle SC-2	EPBRSC2	41.1	5.79	862.0	146.96	20.00	2.52	CON	Yes
0710019	Lee County RRF PSD	Simple Cycle SC-3	EPBRSC3	41.1	5.79	862.0	146.96	20.00	2.52	CON	Yes
			LEECORRF	83.8	1.88	388.5	19.81	5.08	0.64	CON	Yes
0990005	Okeelanta ^a										
		Boiler 4 PSD Baseline	OKBLR4B	22.9	2.29	333.0	7.36	-54.60	-6.88	EXP	Yes
		Boiler 5 PSD Baseline	OKBLR5B	22.9	2.29	333.0	12.07	-54.60	-6.88	EXP	Yes



FACILITIES LEGEND					TERMINAL POINTS	
I.D.	FACILITY	FOUNDATION	TIE-DOWN LOCATION		REMARKS	
			NORTH	SOUTH		
01	COMBUSTION TURBINE	-	-	-	-	T1
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	-	-	-	-	T2
03	HRSG STACK (4-TOTAL)	-	-	-	-	T3
04	STEAM TURBINE	-	-	-	-	T4
05	CT GENERATOR STEP UP TRANSFORMER	-	-	-	-	T5
06	ST GENERATOR STEP UP TRANSFORMER	-	-	-	-	T6
07	SWITCHYARD	-	-	-	-	T7
08	COOLING TOWER	-	-	-	-	T8
09	CIRCULATING WATER LINES	-	-	-	-	T9
10	CIRCULATING WATER PUMPS	-	-	-	-	T10
11	AUXILIARY WATER PUMPS	-	-	-	-	T11
12	FUEL OIL TANK	-	-	-	4.3 MIL. GAL.	T12
13	GAS REGULATING STATION	-	-	-	-	T13
14	CIRC. WATER CHEMICAL FEED AREA	-	-	-	-	T14
15	DEMIN. TANK	-	-	-	2 MIL. GAL.	T15
16	STORMWATER SUMP	-	-	-	-	T16
17	OIL TRUCK UNLOADING STATION	-	-	-	-	T17
18	AMMONIA TANK AND UNLOADING STATION	-	-	-	-	T18
19	DISCHARGE STRUCTURE	-	-	-	-	T19
20	SUBSTATION EXPANSION	-	-	-	-	T20
21	RAW/FIREWATER WATER TANK	-	-	-	5 MIL. GAL.	
22	RESTROOMS	-	-	-	-	
23	WATER & FIRE PUMPS	-	-	-	-	
24	DEMIN. TRAILER AREA	-	-	-	-	
25	WATER TREATMENT AREA	-	-	-	-	
26	RELAY VAULT	-	-	-	-	
27	STORMWATER POND	-	-	-	POTENTIAL	
28	H2 BULK STORAGE	-	-	-	-	

ASPHALT PAVING	AGGREGATE SURFACING	CONCRETE SURFACING
EXISTING FENCING	NEW FENCING	

D 10/24/03 Revised Figure Box/Added Title Code
 REV DATE REVISION DESCRIPTION

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DISCIPLINE	N/A	CS	PLANT/UNIT	TURKEY POINT
SCALE	1"=100'	CD FILE NAME	A-DEP.dwg	FILE
DRAWING SIZE	D(24"x36")	FPL ACQUISITION NAME	N/A	
DRAWING NUMBER	0337800/4/4.2/4.2.2/10.1.5 CCOnly/Figure 2-2.dwg	SHEET	1 OF 1	REV D

Table F-1. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature													Averaging Time	Maximum Predicted Concentrations (ug/m ³) by Operating Load and Air Inlet Temperature ^a												
	Power Aug.	Higher Power Mode			Baseload ^b			75% Load			50% Load				Power Aug.	Higher Power Mode			Baseload			75% Load			50% Load		
	80°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F		80°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F
Natural Gas																											
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.221	0.154	0.166	0.181	0.184	0.197	0.218	0.267	0.269	0.288	0.390	0.391	0.394
														24-Hour	3.531	2.747	2.883	3.092	3.060	3.230	3.496	4.121	4.187	4.480	5.588	5.647	5.781
														8-Hour	8.601	6.727	7.053	7.551	7.482	7.885	8.518	10.048	10.215	10.945	13.644	13.782	14.095
														3-Hour	12.227	8.891	9.428	10.412	10.009	10.732	12.100	14.822	15.130	16.439	20.945	21.169	21.675
														1-Hour	21.103	16.714	17.539	18.794	18.331	19.339	20.937	24.017	24.329	25.690	30.363	30.551	30.959
SO ₂	12.5	10.6	10.3	9.6	13.3	12.8	11.9	8.3	7.9	7.3	6.6	6.4	5.9	Annual	0.0349	0.0205	0.0216	0.0219	0.0309	0.0319	0.0327	0.0277	0.0270	0.0265	0.0324	0.0315	0.0292
														24-Hour	0.558	0.366	0.374	0.374	0.512	0.522	0.524	0.428	0.419	0.411	0.464	0.454	0.428
														3-Hour	1.93	1.19	1.22	1.26	1.67	1.73	1.81	1.54	1.52	1.51	1.74	1.70	1.61
PM ₁₀	14.3	11.1	11.1	10.9	14.4	14.3	14.2	10.7	10.6	10.5	10.3	10.3	10.2	Annual	0.0398	0.0216	0.0232	0.0249	0.0335	0.0356	0.0389	0.0359	0.0360	0.0381	0.0508	0.0507	0.0506
														24-Hour	0.635	0.386	0.402	0.426	0.557	0.584	0.624	0.554	0.560	0.591	0.728	0.732	0.742
NO _x / NO ₂	22.1	17.5	16.9	15.9	24.2	23.6	22.3	13.6	13.1	12.0	10.8	10.4	9.6	Annual	0.0615	0.0339	0.0354	0.0362	0.0563	0.0587	0.0614	0.0457	0.0444	0.0435	0.0528	0.0513	0.0476
CO	68.2	50.5	48.0	44.7	52.3	50.8	48.2	24.4	23.5	21.7	20.1	19.5	18.3	8-Hour	7.394	4.28	4.27	4.25	4.93	5.04	5.17	3.09	3.02	2.99	3.46	3.39	3.25
														1-Hour	18.14	10.64	10.62	10.59	12.08	12.37	12.71	7.38	7.20	7.02	7.71	7.52	7.14
Fuel Oil																											
Generic (10 g/s)	NA	NA	NA	NA	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	NA	NA	NA	NA	0.073	0.080	0.091	0.126	0.129	0.135	0.186	0.186	0.185
														24-Hour	NA	NA	NA	NA	1.545	1.646	1.849	2.443	2.506	2.641	3.443	3.470	3.512
														8-Hour	NA	NA	NA	NA	3.802	4.065	4.557	5.985	6.136	6.466	8.442	8.510	8.622
														3-Hour	NA	NA	NA	NA	5.157	5.426	5.914	8.117	8.431	9.051	12.373	12.502	12.709
														1-Hour	NA	NA	NA	NA	10.741	11.459	12.761	15.818	16.152	16.793	20.775	20.905	21.099
SO ₂	NA	NA	NA	NA	3.1	3.0	2.7	2.5	2.4	2.2	1.9	1.9	1.7	Annual	NA	NA	NA	NA	0.00285	0.00297	0.00305	0.00392	0.00385	0.00367	0.00455	0.00440	0.00403
														24-Hour	NA	NA	NA	NA	0.0602	0.0614	0.0623	0.0757	0.0746	0.0720	0.0842	0.0822	0.0767
														3-Hour	NA	NA	NA	NA	0.201	0.202	0.199	0.252	0.251	0.247	0.303	0.296	0.277
PM ₁₀	NA	NA	NA	NA	17.6	17.6	17.5	17.5	17.5	17.4	17.4	17.4	17.4	Annual	NA	NA	NA	NA	0.0162	0.0177	0.0200	0.0279	0.0285	0.0296	0.0407	0.0407	0.0404
														24-Hour	NA	NA	NA	NA	0.343	0.365	0.409	0.539	0.552	0.580	0.755	0.760	0.768
NO _x / NO ₂	NA	NA	NA	NA	79.5	76.0	68.6	62.5	60.1	55.0	49.0	47.4	43.6	Annual	NA	NA	NA	NA	0.0732	0.0763	0.0784	0.0996	0.0980	0.0934	0.1147	0.1109	0.1015
CO	NA	NA	NA	NA	68.1	64.7	58.9	53.5	51.7	48.3	44.3	43.2	41.0	8-Hour	NA	NA	NA	NA	3.26	3.31	3.38	4.03	4.00	3.94	4.71	4.64	4.46
														1-Hour	NA	NA	NA	NA	9.22	9.33	9.46	10.65	10.53	10.22	11.60	11.39	10.91

^a Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service stations at Miami and Palm Beach International Airports, respectively.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

^b Duct firing included for power augmentation and 100 % load operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of

550 mmBtu/hr (HHV).

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	(lb/hr)	(g/s)		
		Boiler 6 PSD Baseline	OKBLR6B	22.9	2.29	334.0	8.74	-78.00	-9.83	EXP	Yes
		Boiler 10 PSD Baseline	OKBLR10B	22.9	2.29	334.0	10.35	-57.00	-7.18	EXP	Yes
		Boiler 11 PSD Baseline	OKBLR11B	22.9	2.29	342.0	9.89	-55.80	-7.03	EXP	Yes
		Boiler 16 PSD	OKBLR16	22.9	1.52	483.0	22.86	6.10	0.77	CON	Yes
0990332	New Hope Power Partnership (Okeelanta)	Okeelanta Power Blrs 1,2,3 ^b	OKCOGENF	60.7	3.05	450.9	19.39	38.6	4.9	CON	Yes
710002	FPL - Fort Myers	Unit 1 PSD	FMU1	91.8	2.90	422.0	29.90	-169.05	-21.30	EXP	Yes
		Unit 2 PSD	FMU2	121.2	5.52	408.0	19.20	-384.92	-48.50	EXP	Yes
		HRSBs 1 - 6	FMYHR1_6	38.1	5.79	377.6	14.2	60.00	7.56	CON	Yes
0990016	Atlantic Sugar Association ^a	Unit 1	ASA1	27.4	1.83	346.0	17.97	83.97	10.58	CON	Yes
		Unit 2	ASA2	27.4	1.83	350.0	23.36	83.97	10.58	CON	Yes
		Unit 3	ASA3	27.4	1.83	350.0	21.56	78.02	9.83	CON	Yes
		Unit 4	ASA4	27.4	1.83	344.0	25.16	79.76	10.05	CON	Yes
		Unit 5 PSD	ASA5	27.4	1.68	339.0	19.24	35.71	4.50	CON	Yes
		Unit 1 PSD Baseline	ASA1B	18.9	1.92	506.0	12.70	-116.98	-14.74	EXP	Yes
		Unit 2 PSD Baseline	ASA2B	18.9	1.92	511.0	10.90	-141.98	-17.89	EXP	Yes
		Unit 3 PSD Baseline	ASA3B	21.9	1.83	522.0	17.50	-73.97	-9.32	EXP	Yes
		Unit 4 PSD Baseline	ASA4B	18.3	1.83	344.0	15.00	-73.41	-9.25	EXP	Yes
0510015	Southern Gardens Citrus - PSD	Peel Dryer	SGARDDRY	38.1	1.73	316.0	7.45	5.60	0.71	CON	Yes
		Boilers 1-3	SGARDBLR	16.8	1.22	478.0	14.22	1.44	0.18	CON	Yes
0990568	Lake Worth Utilities	Unit 5, S-5	LAKWTHU5	22.9	3.05	481.0	27.80	41.90	5.28	CON	Yes
990026	Sugar Cane Growers ^a	Unit 1&2	SUGCN12	45.7	1.87	339.0	21.75	51.51	6.49	CON	Yes
		Unit 3	SUGCN3	27.4	1.52	339.0	22.25	102.78	12.95	CON	Yes
		Unit 4 PSD	SUGCN4	54.9	2.44	339.0	21.73	98.81	12.45	CON	Yes
		Unit 5	SUGCN5	45.7	2.30	339.0	15.94	98.81	12.45	CON	Yes
		Unit 8 PSD	SUGCN8	47.2	2.90	339.0	13.62	68.02	8.57	CON	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	24.4	1.40	344.0	11.40	-150.32	-18.94	EXP	Yes
		Unit 3 PSD Baseline	SUGCN3B	24.4	1.60	344.0	15.60	-45.24	-5.70	EXP	Yes
		Unit 4 PSD Baseline	SUGCN4B	25.9	1.63	344.0	11.20	-86.51	-10.90	EXP	Yes

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission Rate(g/s)		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	(lb/hr)	(g/s)		
		Unit 5 PSD Baseline	SUGCN5B	24.4	1.40	344.0	15.20	-72.22	-9.10	EXP	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	12.2	1.52	606.0	11.20	-19.84	-2.50	EXP	Yes
0990594	El Paso Belle Glade										
		Combined Cycle CT CC-1	EPBGLCT	41.1	5.79	359.3	61.13	20.00	2.52	CON	Yes
		Simple Cycle SC-1	EPBGSC1	41.1	5.79	862.0	146.96	18.30	2.31	CON	Yes
		Simple Cycle SC-2	EPBGSC2	41.1	5.79	862.0	146.96	18.30	2.31	CON	Yes
		Simple Cycle SC-3	EPBGSC3	41.1	5.79	862.0	146.96	18.30	2.31	CON	Yes
510003	US Sugar - Clewiston ^b										
		Unit 8	USSBLR8	60.7	3.96	439.0	15.30	24.30	3.06	CON	Yes
		<u>PSD Baseline (On-crop season only)</u>									
		Unit 1 PSD Baseline	USSBRL1B	23.1	1.86	344.0	30.20	-59.37	-7.48	EXP	Yes
		Unit 2 PSD Baseline	USSBLR2B	23.1	1.86	343.0	35.70	-55.87	-7.04	EXP	Yes
		Unit 3 PSD Baseline	USSBLR3B	27.4	2.29	342.0	14.70	-36.27	-4.57	EXP	Yes
		East Pellet Plant PSD Baseline	EPELLET	12.2	1.52	347.0	8.54	-13.41	-1.69	EXP	Yes
		West Pellet Plant PSD Baseline	WPELLET	15.7	1.52	347.0	8.54	-6.51	-0.82	EXP	Yes
		Units 5&6 PSD Baseline	USBLR56B	23.1	1.86	494.0	44.30	-420.00	-52.92	EXP	Yes
		<u>On-crop season future</u>									
		Unit 1	USSBLR1N	65.0	2.44	347.0	19.20	115.24	14.52	CON	Yes
		Unit 2	USSBLR2N	65.0	2.44	338.7	17.32	115.24	14.52	CON	Yes
		Unit 4	USSBLR4N	45.7	2.51	344.3	24.03	83.73	10.55	CON	Yes
		Unit 7	USSBLR7N	68.6	2.59	405.4	23.60	22.14	2.79	CON	Yes
		<u>Off-crop season future</u>									
		Unit 1	USSBLR1F	65.0	2.44	347.0	17.70	106.20	13.38	CON	Yes
		Unit 2	USSBLR2F	65.0	2.44	338.7	16.19	97.20	12.25	CON	Yes
		Unit 4	USSBLR4F	45.7	2.51	344.3	0.00	0.00	0.00	CON	Yes
		Unit 7	USSBLR7F	68.6	2.59	405.4	23.60	22.14	2.79	CON	Yes
0990234	Palm Beach Co. Resource Recovery 1&2 PSD		PBCRRF	76.2	2.04	505.2	24.90	23.38	2.95	CON	Yes
0990019	Osceola Farms PSD ^a										
		Unit 1 PSD Baseline	OSBLR1B	22.0	1.52	342.0	8.18	-116.98	-14.74	EXP	Yes
		Unit 2 PSD Baseline	OSBLR2B	22.0	1.52	341.0	18.10	-141.98	-17.89	EXP	Yes
		Unit 3 PSD Baseline	OSBLR3B	22.0	1.93	341.0	14.50	-73.97	-9.32	EXP	Yes
		Unit 4 PSD Baseline	OSBLR4B	22.0	1.83	341.0	18.80	-73.41	-9.25	EXP	Yes
		Unit 2 PSD	OSBLR2	27.4	1.52	341.0	15.82	56.03	7.06	CON	Yes

Table D-2. Detailed summary of Stack, Operating, and Emissions of Facilities with PM₁₀ Emissions Included in the PSD Class I Increment Analysis at the Everglades National Park

AIRS Number	Facility	Units	Modeling ID Name	Stack and Operating Parameters				Emission		PSD Source? (EXP/CON)	Modeled in Class I
				Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Rate(g/s) (lb/hr)	(g/s)		
		Unit 3 PSD	OSBLR3	27.4	1.91	342.0	16.86	58.41	7.36	CON	Yes
		Unit 4 PSD	OSBLR4	27.4	1.83	340.7	22.80	44.40	5.59	CON	Yes
		Unit 5a	OSBLR5A	27.4	1.52	340.7	18.60	22.20	2.80	CON	Yes
		Unit 5b	OSBLR5B	27.4	1.52	340.7	18.60	23.20	2.92	CON	Yes
		Unit 6 PSD	OSBLR6	27.4	1.88	341.0	18.19	56.90	7.17	CON	Yes
990061	US Sugar-Bryant ^a	Unit 5 PSD	USSBRY5	42.7	2.90	345.0	11.49	99.92	12.59	CON	Yes
		Unit 1,2&3	USBRY123	19.8	1.64	342.0	36.40	346.51	43.66	CON	Yes
		Unit 1 PSD Baseline	USSBRY1B	19.8	1.68	494.0	44.30	-653.97	-82.40	EXP	Yes
		Unit 2&3 PSD Baseline	USBRY23B	19.8	1.68	344.0	37.90	-95.56	-12.04	EXP	Yes
990021	Pratt & Whitney (United Technologies)	Boiler BO-12, -1, -2, -14, -3	PRATBO12	4.6	0.76	533.2	6.92	0.29	0.04	CON	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	150.9	4.88	333.2	30.50	47.42	5.97	CON	Yes
850001	FPL -Martin										
		Aux Blr PSD	MART AUX	18.3	1.10	535.4	15.24	0.10	0.01	CON	Yes
		Diesel Gens PSD	MART GEN	7.6	0.30	785.9	39.62	1.72	0.22	CON	Yes
		Units 3&4 PSD	MART34	64.9	6.10	410.9	18.90	242.40	30.54	CON	Yes
		Unit 8	MART8OIL	36.6	5.79	420.0	22.40	151.20	19.05	CON	Yes

Note: EXP = PSD expanding source
 CON = PSD consuming source

^a Facilities or sources within facilities that operate only during the October 1 through April 30 crop season.
^b Sugar mill sources that operate all year.
^c Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.

Table F-2. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation
PSD Class I Area of the Everglades National Park

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature												Averaging Time	Maximum Predicted Concentrations (ug/m ³) by Operating Load and Air Inlet Temperature *													
	Power Aug.				Higher Power Mode				Baseload ^b					75% Load				50% Load									
	80°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F	95°F	35°F	59°F		95°F	35°F	59°F	95°F	35°F	59°F	95°F							
Natural Gas Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual 24-Hour 8-Hour 3-Hour 1-Hour	0.059 0.595 1.247 2.783 5.268	0.053 0.550 1.094 2.346 4.513	0.054 0.558 1.109 2.390 4.622	0.055 0.568 1.131 2.456 4.788	0.056 0.574 1.149 2.521 4.910	0.057 0.582 1.184 2.615 5.040	0.059 0.593 1.236 2.753 5.225	0.062 0.618 1.442 3.082 5.665	0.062 0.619 1.449 3.099 5.683	0.063 0.628 1.494 3.223 5.838	0.069 0.722 1.747 3.968 6.613	0.069 0.723 1.749 3.973 6.614	0.069 0.723 1.750 3.974 6.601
SO ₂	12.5	10.6	10.3	9.6	13.3	12.8	11.9	8.3	7.9	7.3	6.6	6.4	5.9	Annual 24-Hour 8-Hour 3-Hour 1-Hour	0.00929 0.0940 0.1970 0.440 0.832	0.00708 0.0734 0.1458 0.313 0.602	0.00701 0.0723 0.1438 0.310 0.599	0.00668 0.0688 0.1370 0.297 0.580	0.00932 0.0960 0.1922 0.422 0.821	0.00922 0.0940 0.1915 0.423 0.815	0.00878 0.0888 0.1852 0.413 0.783	0.00640 0.0642 0.1500 0.320 0.589	0.00618 0.0620 0.1451 0.310 0.569	0.00579 0.0576 0.1372 0.296 0.536	0.00572 0.0600 0.1452 0.330 0.549	0.00554 0.0581 0.1407 0.320 0.532	0.00511 0.0535 0.1296 0.294 0.489
PM ₁₀	14.3	11.1	11.1	10.9	14.4	14.3	14.2	10.7	10.6	10.5	10.3	10.3	10.2	Annual 24-Hour 8-Hour 3-Hour 1-Hour	0.0106 0.107 0.224 0.501 0.948	0.0075 0.077 0.154 0.329 0.633	0.0076 0.078 0.155 0.334 0.645	0.0076 0.078 0.156 0.339 0.660	0.0101 0.104 0.209 0.458 0.893	0.0103 0.105 0.214 0.473 0.911	0.0104 0.106 0.220 0.491 0.932	0.0083 0.083 0.194 0.414 0.761	0.0082 0.083 0.197 0.414 0.760	0.0083 0.083 0.197 0.425 0.770	0.0090 0.094 0.227 0.517 0.861	0.0089 0.094 0.227 0.515 0.858	0.0088 0.093 0.225 0.510 0.847
NO _x /NO ₂	22.1	17.5	16.9	15.9	24.2	23.6	22.3	13.6	13.1	12.0	10.8	10.4	9.6	Annual 24-Hour 8-Hour 3-Hour 1-Hour	0.0163 0.1654 0.3467 0.7735 1.4646	0.0117 0.1214 0.2414 0.5178 0.9960	0.0115 0.1186 0.2358 0.5083 0.9331	0.0111 0.1139 0.2268 0.4925 0.9599	0.0170 0.1750 0.3504 0.7690 1.4977	0.0170 0.1731 0.3524 0.7782 1.5000	0.0165 0.1667 0.3476 0.7741 1.4692	0.0105 0.1057 0.2468 0.5273 0.9693	0.0102 0.1021 0.2388 0.5108 0.9367	0.0095 0.0948 0.2256 0.4867 0.8815	0.0093 0.0978 0.2367 0.5376 0.8957	0.0090 0.0947 0.2293 0.5210 0.8672	0.0083 0.0872 0.2112 0.4797 0.7969
CO	68.2	50.5	48.0	44.7	52.3	50.8	48.2	24.4	23.5	21.7	20.1	19.5	18.3	Annual 24-Hour 8-Hour 3-Hour 1-Hour	0.051 0.512 1.072 2.392 4.53	0.034 0.350 0.696 1.493 2.87	0.033 0.338 0.671 1.447 2.80	0.031 0.320 0.637 1.383 2.70	0.037 0.378 0.757 1.661 3.24	0.037 0.372 0.751 1.673 3.22	0.036 0.360 0.751 1.672 3.17	0.019 0.190 0.443 0.946 1.74	0.018 0.183 0.429 0.918 1.68	0.017 0.172 0.408 0.881 1.60	0.017 0.183 0.443 1.007 1.68	0.017 0.178 0.431 0.979 1.63	0.016 0.167 0.404 0.917 1.52
Fuel Oil Generic (10 g/s)	NA	NA	NA	NA	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual 24-Hour 8-Hour 3-Hour 1-Hour	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	0.040 0.435 0.836 1.658 2.913	0.041 0.446 0.865 1.714 3.036	0.043 0.465 0.908 1.811 3.254	0.049 0.513 1.007 2.075 3.862	0.049 0.516 1.014 2.094 3.908	0.050 0.522 1.026 2.127 3.987	0.055 0.566 1.188 2.406 4.667	0.055 0.566 1.188 2.405 4.664	0.055 0.565 1.184 2.396 4.642
SO ₂	NA	NA	NA	NA	3.1	3.0	2.7	2.5	2.4	2.2	1.9	1.9	1.7	Annual 24-Hour 8-Hour 3-Hour 1-Hour	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	0.00154 0.0170 0.0326 0.0646 0.1136	0.00152 0.0166 0.0322 0.0639 0.1132	0.00145 0.0157 0.0306 0.0610 0.1096	0.00151 0.0159 0.0312 0.0643 0.1197	0.00146 0.0154 0.0302 0.0624 0.1164	0.00136 0.0142 0.0280 0.0580 0.1087	0.00134 0.0138 0.0291 0.0589 0.1142	0.00130 0.0134 0.0281 0.0569 0.1104	0.00119 0.0123 0.0258 0.0523 0.1013
PM ₁₀	NA	NA	NA	NA	17.6	17.6	17.5	17.5	17.5	17.4	17.4	17.4	17.4	Annual 24-Hour 8-Hour 3-Hour 1-Hour	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	0.0088 0.097 0.186 0.368 0.647	0.0090 0.099 0.192 0.380 0.673	0.0095 0.103 0.201 0.400 0.719	0.0107 0.113 0.222 0.457 0.851	0.0108 0.114 0.223 0.461 0.861	0.0109 0.115 0.226 0.467 0.876	0.0120 0.124 0.260 0.527 1.023	0.0120 0.124 0.260 0.527 1.021	0.0120 0.123 0.259 0.524 1.015
NO _x /NO ₂	NA	NA	NA	NA	79.5	76.0	68.6	62.5	60.1	55.0	49.0	47.4	43.6	Annual 24-Hour 8-Hour 3-Hour 1-Hour	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	0.0396 0.4359 0.8368 1.6602 2.9177	0.0391 0.4271 0.8279 1.6410 2.9077	0.0372 0.4023 0.7848 1.5659 2.8135	0.0383 0.4039 0.7930 1.6345 3.0427	0.0371 0.3910 0.7683 1.5869 2.9616	0.0345 0.3619 0.7119 1.4754 2.7655	0.0338 0.3488 0.7330 1.4840 2.8785	0.0327 0.3375 0.7090 1.4349 2.7828	0.0300 0.3103 0.6506 1.3164 2.5506
CO	NA	NA	NA	NA	68.1	64.7	58.9	53.5	51.7	48.3	44.3	43.2	41.0	Annual 24-Hour 8-Hour 3-Hour 1-Hour	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	0.034 0.373 0.717 1.422 2.50	0.033 0.363 0.704 1.396 2.47	0.032 0.345 0.673 1.343 2.41	0.033 0.345 0.678 1.397 2.60	0.032 0.336 0.661 1.365 2.55	0.030 0.318 0.625 1.295 2.43	0.031 0.316 0.663 1.343 2.61	0.030 0.308 0.647 1.310 2.54	0.028 0.292 0.612 1.239 2.40

* Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991
of surface and upper air data from the National Weather Service stations at Miami and Palm Beach International Airports, respectively.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s).
Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant
emission rate to the modeled emission rate of 10 g/s.

^b Duct firing included for power augmentation and 100 % load operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of

550 mmBtu/hr (HHV).

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- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
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1. Article Addressed to:

Mr. H. O. Nunez
Plant General Manager
FPL Turkey Point Fossil Plant
9700 Southwest 344 Street
Homestead, FL 33035

2. Article Number (Copy from service label)

7099 3220 0003 6189 5273

PS Form 3811, July 1999

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102595-99-M-1789

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appeared:

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who on oath says that he/she is

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of The Miami Herald, a daily newspaper published at
Miami in Miami-Dade County, Florida; that the
attached copy of advertisement was published in said
newspaper in the issues of:

June 10, 2004

Affiant further says that the said The Miami Herald
is a newspaper published at Miami, in the said
Miami-Dade County, Florida and that the said
newspaper has heretofore been continuously published
in said Miami-Dade County, Florida each day and has
been entered as second class mail matter at the post
office in Miami, in said Miami-Dade County, Florida,
for a period of one year next preceding the first
publication of the attached copy of advertisement;
and affiant further says that he has neither paid nor
promised any person, firm or corporation any discount,
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securing this advertisement for publication in the said
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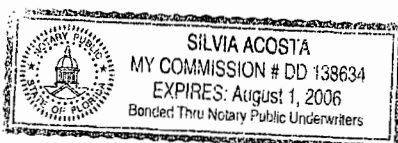
Sworn to and subscribed before me this
_15th day of _June 2004

My Commission

Expires: August 1, 2006

Silvia Acosta

Notary



PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0250003-006-AC (PSD-FL-338)

FPL Turkey Point Fossil Plant, New Combined Cycle Unit 5
Miami-Dade County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power & Light Company. The permit is one of several authorizations needed to construct a nominal 1,150 MW combined cycle natural gas-fired unit at the existing Turkey Point Fossil Plant east of Homestead and Florida City, and adjacent to Biscayne Bay in Miami-Dade County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM₁₀), sulfur dioxide (SO₂), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's corporate address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

The applicant proposes to construct a new electrical power generating unit (Unit 5). The primary components are: four combustion turbine-electrical generators; four supplementary-fired heat recovery steam generators (HRSGs); a single steam-electrical generator; a 22-cell mechanical draft cooling tower; four exhaust stacks; a 4.3 million gallon diesel fuel storage tank; and other associated support equipment.

Unit 5 will be permitted to operate continuously while firing inherently clean natural gas. Ultra low sulfur (0.0015 percent sulfur) distillate fuel oil will be available in Southeast Florida by the time the project starts up. Its use will be allowed as backup fuel for 500 hours per year per combustion turbine. Steam injection into the combustion turbines (power augmentation) and firing of natural gas in the duct burners located within the HRSGs (supplemental firing) will be allowed for limited periods of time to meet peak power demand.

A selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with Dry Low-NOx combustion (gas firing) and wet injection (oil firing) to control NOx emissions. The proposed NOx emission limit of 2.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmv @15% O₂) of NOx while firing natural gas represents the most protective standard for any project authorized to date in the Southeastern United States. Sufficient catalyst will be used to minimize emissions of ammonia reagent. The proposed NOx limit while firing ultra low sulfur fuel oil is 8 ppmv @15% O₂. The proposed CO emission limits of 4.1 and 8.0 ppmv @15% O₂ while burning gas and oil respectively represent the lowest values guaranteed to-date without requiring oxidation catalyst. Typical CO emissions will actually be 2 ppmv or less under most operational modes.

Emissions of CO, PM₁₀, SAM, SO₂, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean fuels. Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. The complete set of proposed emission limits is available at the Department offices, the local Miami-Dade County DERM office and website addresses indicated below.

The applicant's estimate of maximum potential annual emissions from Unit 5 are summarized in the following table.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	464	100	Yes
Pb	0.026	0.6	No
NOx	312	40	Yes
PM ₁₀	420/229	25/15	Yes
SO ₂	193	40	Yes
SAM	19	7	Yes
VOC	68	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards Class II increments. The predicted impacts in the Class I Everglades National Park (ENP) are less than the applicable significant impact levels except for the 3-hour and 24-hour SO₂ and 24-hour PM₁₀ impacts. Therefore multi-source increment modeling was required for the 3-hour and 24-hour SO₂ and 24-hour PM₁₀ impacts upon the ENP. The following table summarizes the maximum predicted 3-hour and 24-hour SO₂ and 24-hour PM₁₀ increment consumption by the new project and by all project in the general area since 1977.

Averaging Time	PM ₁₀ Increment Consumed in ug/m ³ and % at ENP		SO ₂ Increment Consumed in ug/m ³ and % at ENP	
	By Project	All Sources	By Project	All Sources
24-hour	0.5 (10% of Allowable)	2.1 (42% of Allowable)	0.4 (8% of Allowable)	4.1 (82% of Allowable)
3-hour	No Analysis Required	No Analysis Required	2 (8% of Allowable)	18 (72% of Allowable)

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. A small impact on air quality related values (visibility) was projected to occur approximately 2 days in three years if ultra low sulfur fuel oil is continuously fired, instead of natural gas, and the ambient temperature is 35 degrees F. Because fuel oil will be used less than 10 percent of the time and such low temperatures are atypical for the South Florida coastline, the coincidence of the factors that promote visibility impact is minimal. The probability of such an occurrence is less than one every three years.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's intent to issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

Miami-Dade Department of
Environmental Resource Management
33 SW 2nd Avenue, Suite 900
Miami, Florida 33130-1540
Telephone: 305/372-6925
Fax: 305/372-6954

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact A. A. Linero or Debbie Nelson of the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. Address e-mail comments to alvaro.linero@dep.state.fl.us. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/air/permitting/construction/turkeypoint.htm.

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. H.O. Nunez, Plant General Manager
Florida Power and Light Company,
Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

2. Article Number

(Transfer from service label)

7000 1670 0013 3110 2325

PS Form 3811, August 2001

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A. Signature

[Signature] ☒ Agent
☐ Addressee

B. Received by (Printed Name)

SECURITY

C. Date of Delivery

2/12/5

D. Is delivery address different from item 1? ☒ YesIf YES, enter delivery address below: ☐ No

3. Service Type

- ☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Randall R. LaBauve
Vice President
Environmental Services
Flower Power & Light
700 Universe Blvd.
Juno Beach, Florida 33408

2. Article Number

(Transfer from service label)

PS Form 3811, August 2001

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A. Signature

X *[Signature]* ☒ Agent
☐ Addressee

B. Received by (Printed Name)

G. ADAMS

C. Date of Delivery

2-11-5

D. Is delivery address different from item 1? ☐ YesIf YES, enter delivery address below: ☐ No

3. Service Type

- ☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ YesU.S. Postal Service
CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

Postage \$

Certified Fee

Return Receipt Fee
(Endorsement Required)Restricted Delivery Fee
(Endorsement Required)

Total P

Postmark
Here

Sent To

Mr. H.O. Nunez, Plant General Manager
Florida Power and Light Company,
Turkey Point Fossil Plant
9700 Southwest 344th Street
Homestead, Florida 33035

PS Form 3800, May 2000

Instructions

U.S. Postal Service
CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

Postage \$

Certified Fee

Return Receipt Fee
(Endorsement Required)Restricted Delivery Fee
(Endorsement Required)Postmark
Here

Mr. Randall R. LaBauve

Vice President

Environmental Services

Flower Power & Light

700 Universe Blvd.

Juno Beach, Florida 33408

Instructions

Florida Lakes Power Partners

9700 SW 344th Street
PO Box 344160
Homestead, FL 33035

TRANSMITTAL

No. 00417

PROJECT: 7261 Turkey Point

DATE: 01/03/2007

TO: Florida Department of Environmental
Fl Dept of Environmental Protection
Division of Air Resource Management
Tallahassee, FL 32399-2400

REF: Letter # TP00043

RECEIVED

JAN 04 2007

ATTN: Trina Vielhauer

BUREAU OF AIR REGULATION

WE ARE SENDING:	SUBMITTED FOR:	ACTION TAKEN:
☐ Shop Drawings	☐ Approval	☐ Approved as Submitted
☐ Letter	☒ Your Use	☐ Approved as Noted
☐ Prints	☐ As Requested	☐ Returned After Loan
☐ Change Order	☐ Review and Comment	☐ Resubmit
☐ Plans		☐ Submit
☐ Samples	SENT VIA:	☐ Returned
☐ Specifications	☒ Attached	☐ Returned for Corrections
☐ Other:	☐ Separate Cover Via:	☐ Due Date:

ITEM	PACKAGE	SUBMITTAL	DRAWING	REV.	ITEM NO.	COPIES	DATE	DESCRIPTION	STATUS
LTR					01	1	01/02/2006	Initial Startup of Turkey Point Combustion Turbine #TPCT5B	

Remarks:

Please sign & return by fax to:

Barbara @ 786-243-7776

Signature: 

returned by fax on 1/9 @ 2:50 pm - VS

CC:

Signed:

John Tidwell

FLORIDA LAKES POWER PARTNERS, LLC

11401 Lamar Avenue
Overland Park, Kansas 66211
Tel: (913) 458-2000
Fax: (913) 458-4018 or 2934

527 Logwood
San Antonio, TX 78221
Ph: 210-475-8264
Fax: 210-475-8572

Florida Power & Light Company
Turkey Point Expansion Project – Unit 5

FLPP Project 138729
FLPP File 32.0585
FLPP-2006-TP-_00043
January 2, 2007
E-mail, Overnight Mail

Attention: Trina Vielhauer
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Bureau Chief
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Initial Startup of Turkey Point Combustion Turbine # TPCT5B

Dear Ms. Vielhauer,

On behalf of Florida Power & Light Company (FPL) and its Designated Representative, R. Bryan Fennell, the Florida Lakes Power Partners, LLC (FLPP), general contractor for construction of the new combined cycle generating unit at the FPL Turkey Point Unit 5 project, is sending you this notification in accordance with the regulations cited below.

This correspondence is to serve as notification to the Department, in accordance with 40 CFR 60.7(a)(3), FPL first fired Combustion Turbine # TPCT5B on December 27, 2006.

If you have any questions regarding this notification, please do not hesitate to contact me at (305) 247-4802.

Very truly yours,

FLORIDA LAKES POWER PARTNERS, LLC


John Tidwell
Project Manager

TRANSMISSION VERIFICATION REPORT

TIME : 01/09/2007 14:51
NAME : DIVISION OF AIR
FAX : 8509219533
TEL : 8504380114
SER.# : BROG2J567933

DATE, TIME
FAX NO./NAME
DURATION
PAGE(S)
RESULT
MODE

01/09 14:50
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00:00:21
01
OK
STANDARD
ECM

FLORIDA LAKES POWER PARTNERS, LLC

11401 Lamar Avenue
Overland Park, Kansas 66211
Tel: (913) 458-2000
Fax: (913) 458-4018 or 2934

527 Logwood
San Antonio, TX 78221
Ph: 210-475-8264
Fax: 210-475-8572

RECEIVED

JAN 03 2007

Florida Power & Light Company
Turkey Point Expansion Project – Unit 5

FLPP Project 138729
FLPP File 32.0585
FLPP-2006-TP-_00043
January 2, 2007
E-mail, Overnight Mail

BUREAU OF AIR REGULATION

Attention: Trina Vielhauer
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Bureau Chief
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Initial Startup of Turkey Point Combustion Turbine # TPCT5B

Dear Ms. Vielhauer,

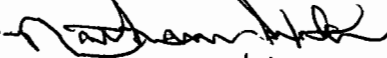
On behalf of Florida Power & Light Company (FPL) and its Designated Representative, R. Bryan Fennell, the Florida Lakes Power Partners, LLC (FLPP), general contractor for construction of the new combined cycle generating unit at the FPL Turkey Point Unit 5 project, is sending you this notification in accordance with the regulations cited below.

This correspondence is to serve as notification to the Department, in accordance with 40 CFR 60.7(a)(3), FPL first fired Combustion Turbine # TPCT5B on December 27, 2006.

If you have any questions regarding this notification, please do not hesitate to contact me at (305) 247-4802.

Very truly yours,

FLORIDA LAKES POWER PARTNERS, LLC


for John Tidwell

John Tidwell
Project Manager

cc: Hamilton Oven, FDEP Siting Office
Errin Pichard, FDEP Air Resource Management
Tim Gray, FDEP Southeast District
Darrel Graziani, FDEP Southeast District Program Administrator
David McNeal, USEPA Region 4
Kevin Tran, USEPA Clean Air Markets Division
Lee Hefty, DERM
Luis Otero, DERM
R. Bryan Fennell, FPL Designated Representative
Tom Young, FPL Construction Project General Manager
Ed Nuñez, FPL Plant General Manager
Gary Andersen, FPL Environmental Manager
Marister Ruiz, FPL Environmental Specialist
Mike Szybinski, FPL PGD
Loretta Cranmer, FPL PGD
Mike Perkins, FLPP-KC
John Tidwell, FLPP-TP Office
Dale Woltman/File, FLPP-KC
Terry Apple, FLPP-KC
PTF_Combined_Cycle_Project@fpl.com

FLORIDA LAKES POWER PARTNERS, LLC

11401 Lamar Avenue
Overland Park, Kansas 66211
Tel: (913) 458-2000
Fax: (913) 458-4018 or 2934

527 Logwood
San Antonio, TX 78221
Ph: 210-475-8264
Fax: 210-475-8572

Florida Power & Light Company
Turkey Point Expansion Project – Unit 5

FLPP Project 138729
FLPP File 32.0585
FLPP-2006-TP-_00041
December 20, 2006
E-mail, Overnight Mail

Attention: Trina Vielhauer
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Bureau Chief
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Initial Startup of Turkey Point Combustion Turbine # TPCT5A

Dear Ms. Vielhauer,

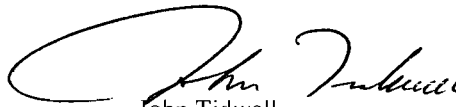
On behalf of Florida Power & Light Company (FPL) and its Designated Representative, R. Bryan Fennell, the Florida Lakes Power Partners, LLC (FLPP), general contractor for construction of the new combined cycle generating unit at the FPL Turkey Point Unit 5 project, is sending you this notification in accordance with the regulations cited below.

This correspondence is to serve as notification to the Department, in accordance with 40 CFR 60.7(a)(3), FPL first fired Combustion Turbine # TPCT5A on December 19, 2006.

If you have any questions regarding this notification, please do not hesitate to contact me at (305) 247-4802.

Very truly yours,

FLORIDA LAKES POWER PARTNERS, LLC



John Tidwell
Project Manager

cc: Hamilton Oven, FDEP Siting Office
Errin Pichard, FDEP Air Resource Management
Tim Gray, FDEP Southeast District
Darrel Graziani, FDEP Southeast District Program Administrator
David McNeal, USEPA Region 4
Lee Hefty, DERM
Luis Otero, DERM
R. Bryan Fennell, FPL Designated Representative
Tom Young, FPL Construction Project General Manager
Ed Nuñez, FPL Plant General Manager
Gary Andersen, FPL Environmental Manager
Marister Ruiz, FPL Environmental Specialist
Mike Szybinski, FPL PGD
Loretta Cranmer, FPL PGD
Mike Perkins, FLPP-KC
John Tidwell, FLPP-TP Office
Dale Woltman/File, FLPP-KC
Terry Apple, FLPP-KC
PTF_Combined_Cycle_Project@fpl.com

Florida Lakes Power Partners

9700 SW 344th Street
PO Box 344160
Homestead, FL 33035

TRANSMITTAL

No. 00415

PROJECT: 7261 Turkey Point

DATE: 12/20/2006

TO: Florida Department of Environmental
Fl Dept of Environmental Protection
Division of Air Resource Management
Tallahassee, FL 32399-2400

REF: Ltr. #TP00041

RECEIVED

DEC 21 2006

ATTN: Trina Vielhauer

BUREAU OF AIR REGULATION

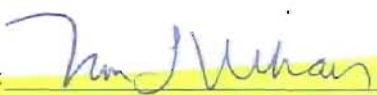
WE ARE SENDING:	SUBMITTED FOR:	ACTION TAKEN:
☐ Shop Drawings	☐ Approval	☐ Approved as Submitted
☐ Letter	☒ Your Use	☐ Approved as Noted
☐ Prints	☐ As Requested	☐ Returned After Loan
☐ Change Order	☐ Review and Comment	☐ Resubmit
☐ Plans		☐ Submit
☐ Samples	SENT VIA:	☐ Returned
☐ Specifications	☒ Attached	☐ Returned for Corrections
☐ Other:	☐ Separate Cover Via:	☐ Due Date:

ITEM	PACKAGE	SUBMITTAL	DRAWING	REV.	ITEM NO.	COPIES	DATE	DESCRIPTION	STATUS
LTR				01		1	12/20/2006	Initial Startup of Turkey Point Combustion Turbine #TPCT5A	

Remarks:

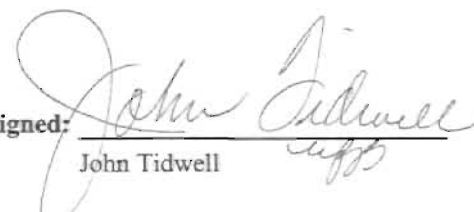
Please sign & return by fax to:

Barbara @ 786-243-7776

Signature: 

fax returned on 12/28/06 @ 2:47pm - VS

CC:

Signed: 

John Tidwell

TRANSMISSION VERIFICATION REPORT

TIME : 12/28/2006 14:48
NAME : DIVISION OF AIR
FAX : 8509219533
TEL : 8504880114
SER.# : BROG2J567933

DATE, TIME	12/28 14:47
FAX NO./NAME	617862437776
DURATION	00:00:21
PAGE(S)	01
RESULT	OK
MODE	STANDARD ECM

TRANSMISSION VERIFICATION REPORT

TIME : 12/26/2006 14:41
NAME : DIVISION OF AIR
FAX : 8509219533
TEL : 8504880114
SER.# : BROG2J567933

DATE, TIME	12/26 14:41
FAX NO./NAME	617862437776
DURATION	00:00:00
PAGE(S)	00
RESULT	BUSY
MODE	STANDARD

BUSY: BUSY/NO RESPONSE

FLORIDA LAKES POWER PARTNERS, LLC

11401 Lamar Avenue
Overland Park, Kansas 66211
Tel: (913) 458-2000
Fax: (913) 458-4018 or 2934

527 Logwood
San Antonio, TX 78221
Ph: 210-475-8264
Fax: 210-475-8572

Florida Power & Light Company
Turkey Point Expansion Project – Unit 5

FLPP Project 138729
FLPP File 32.0585
FLPP-2005-TP-_00039
December 12, 2006
E-mail, Overnight Mail, Fax

Attention: Trina Vielhauer
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Bureau Chief
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Initial Startup of Turkey Point Combustion Turbine # TPCT5C

Dear Ms. Vielhauer,

On behalf of Florida Power & Light Company (FPL) and its Designated Representative, R. Bryan Fennell, the Florida Lakes Power Partners, LLC (FLPP), general contractor for construction of the new combined cycle generating unit at the FPL Turkey Point Unit 5 project, is sending you this notification in accordance with the regulations cited below.

This correspondence is to serve as notification to the Department, in accordance with 40 CFR 60.7(a)(3), FPL first fired Combustion Turbine # TPCT5C on December 12, 2006.

If you have any questions regarding this notification, please do not hesitate to contact me at (305) 247-4802.

Very truly yours,

FLORIDA LAKES POWER PARTNERS, LLC



John Tidwell
Project Manager

cc: Hamilton Oven, FDEP Siting Office
Errin Pichard, FDEP Air Resource Management
Tim Gray, FDEP Southeast District
Darrel Graziani, FDEP Southeast District Program Administrator
David McNeal, USEPA Region 4
Lee Hefty, DERM
Luis Otero, DERM
R. Bryan Fennell, FPL Designated Representative
Tom Young, FPL Construction Project General Manager
Ed Nuñez, FPL Plant General Manager
Gary Andersen, FPL Environmental Manager
Marister Ruiz, FPL Environmental Specialist
Mike Szybinski, FPL PGD
Loretta Cranmer, FPL PGD
Mike Perkins, FLPP-KC
John Tidwell, FLPP-TP Office
Dale Woltman/File, FLPP-KC
Terry Apple, FLPP-KC
PTF_Combined_Cycle_Project@fpl.com

Florida Lakes Power Partners

9700 SW 344th Street
PO Box 344160
Homestead, FL 33035

TRANSMITTAL

No. 00411

PROJECT: 7261 Turkey Point

DATE: 12/12/2006

TO: Florida Department of Environmental
FL Dept of Environmental Protection
Division of Air Resource Management
Tallahassee, FL 32399-2400

REF: Ltr #TP00039

RECEIVED

DEC 13 2006

ATTN: Trina Vielhauer

BUREAU OF AIR REGULATION

WE ARE SENDING:	SUBMITTED FOR:	ACTION TAKEN:
☐ Shop Drawings	☐ Approval	☐ Approved as Submitted
☐ Letter	☒ Your Use	☐ Approved as Noted
☐ Prints	☐ As Requested	☐ Returned After Loan
☐ Change Order	☐ Review and Comment	☐ Resubmit
☐ Plans		☐ Submit
☐ Samples	SENT VIA:	☐ Returned
☐ Specifications	☒ Attached	☐ Returned for Corrections
☐ Other:	☐ Separate Cover Via:	☐ Due Date:

ITEM	PACKAGE	SUBMITTAL	DRAWING	REV.	ITEM NO.	COPIES	DATE	DESCRIPTION	STATUS
LTR					01	1	12/12/2006	Initial Startup of Turkey Point Combustion Turbine #TPCT5C	

Remarks:

Please sign and return by fax to:

Barbara @ 786-247-4802

Signature: Trina Vielhauer

CC:

Signed: John Tidwell

John Tidwell



November 8, 2006

RECEIVED

NOV 09 2006

BUREAU OF AIR REGULATION

Trina Vielhauer
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulations, Bureau Chief
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: **FPL Turkey Point Expansion Project**
PA 03-45 Conditions of Certification & PSD-FL-338
Cooling Tower Drift Certification

Dear Ms. Vielhauer,

FPL's Turkey Point Expansion Project Condition of Certification XXVIII.C. 4. and Prevention of Significant Deterioration (PSD) permit PSD-FL-338 Section III. C. 2. read as follows:

"Within 60 days of commencing operation, the licensee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate."

In accordance with these conditions, FPL is hereby submitting the drift certification letter provided by GEA Power and Cooling, Inc.

Please let me know if you have any questions and/or require additional information. You can reach me at (561) 691-7518.

Sincerely,

Barbara P. Linkiewicz

Environmental Licensing Manager
Florida Power & Light Company

cc: Darrel Graziani, DEP Southeast District Office
Errin Pichard, DEP Division of Air Resource Management
Laxamana Tallam, DEP Southeast District Office
Lee Hefty, DERM
Luis Otero, DERM
Steven Palmer, DEP Siting Office



GEA Power Cooling, Inc.

143 Union Blvd., Suite 400
Lakewood, Colorado 80228
Telephone: (303) 987-0123
Facsimile: (303) 987-0101

April 27, 2005

Mr. Dale Woltman
Florida Lakes Power Partners
c/o Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66211

Subject: Turkey Point Expansion Project
Homestead, Florida
Subcontract Number 138729.62.0601
GEA Job Number 05-003

Dear Mr. Woltman:

GEA Power Cooling, Inc. hereby certifies that the cooling tower provided at the Turkey Point Expansion Project has been designed and constructed in accordance with the drift rate guarantee as specified in Subcontract Number 138729.62.0601.

Should you have any questions or require additional information, please do not hesitate to contact me at your convenience.

Very truly yours,

Jason Nesseth
Project Manager

cc: A. Atherton
T. Farber



Lightning protection system (specified in the attached Technical Specification)		Yes
Erection (specified herein and in the attached Technical Specification)		Yes
Tower type	Rectangular, Multi-Cell, Counter Flow, Induced Mechanical Draft	
Structural framework material	Fiberglass	
Circulating water quality	Saltwater from ground - See Attachments 5 and 6	
Cooling tower orientation	Long Axis of Tower is East-West	
Cooling tower arrangement	Back to Back (Maximum area 650'-0" x 100'-0")	
Cooling tower fill media type	Low Clog Vertically Fluted Film Fill - GEA AFE-20	
The selected fill shall have a minimum of 10 years of successful in service operation. The Supplier shall provide a sample of the selected fill to the Purchaser for review.		
Economic evaluation of proposals will be made on the basis of the following costs:		
Fan motor auxiliary power, per kW	\$2034 per kW For Each kW in Excess of 3,350 kW	
Tower pumping head, per ft H ₂ O	\$140,400 per foot For Each Foot of Pumping Head in Excess of 42.0 Feet.	
Design conditions, each tower		
Inlet circulating water flow, gpm	296,800	
Inlet circulating water temperature, °F	105.6	
Outlet circulating water temperature, °F	87.0	
Ambient wet-bulb temperature, °F	79.1	
Inlet wet-bulb temperature, °F	81.1	
Ambient dry-bulb temperature, °F	95.00	
Drift, maximum percent of inlet circulating water flow	0.0005	
Off-design conditions, each tower		
Inlet circulating water flow, gpm (lpm)	296,800	
Inlet circulating water temperature, °F	92.6	
Outlet circulating water temperature, °F	77.0	
Ambient wet-bulb temperature, °F	65.3	
Inlet wet-bulb temperature, °F	67.3	
Maximum expected dry-bulb temperature, °F	101.0	
Minimum expected dry-bulb temperature, °F	30.0	
Maximum expected wet-bulb temperature, °F	84.0	
Minimum expected wet-bulb temperature, °F	30.0	